SPE/IADC-221436-MS

MPD Well Control During Non-Drilling Operations

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This paper was prepared for presentation at the SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition held in Rio de Janeiro, Brazil, USA, 17 – 18 September, 2024.

Abstract

This study aims to advance the understanding of influx management in Managed Pressure Drilling (MPD) operations. Despite industry efforts to improve kick management using Coriolis flow meters in combination with algorithms for influx volume estimation, and well-established processes for kick circulation, such as Influx Management Envelope (IME) and the MPD matrix, there is still a literature gap regarding kick management with the bit off bottom - a common scenario during tripping, reaming, mud displacement, or running liners.

The identification and control of a kick with the bit off bottom introduces additional complexities, including pipe movement, fluctuating pump pressures, the absence of Equivalent Circulating Density (ECD) readings at the well's total depth (as the bottom hole assembly is off bottom), and temperature effects. These factors may lead to misinterpretations during off-bottom operations, potentially resulting in false alarms. Attempting to control a kick with MPD using drilling procedures may lead to elevated surface pressures or unnecessary and costly killing operations with heavier mud.

This work focuses on analyzing the risks and consequences associated with controlling kicks off bottom with the MPD system while exploring potential solutions, considering both false alarms and true kicks into the wellbore. The analysis is supported by hydraulic simulations and insights from real field experience.

The outcomes of this study will serve as a comprehensive guideline to enhance understanding, mitigate risks, and further development of influx management procedures for MPD, expanding coverage beyond drilling operations to include off-bottom scenarios.

Introduction

Gillard et al. (2022) report that about half of the globally recorded influx incidents occur while drilling on-bottom. With the growing use of MPD, which greatly enhances the kick detection capabilities, drillers have developed significant expertise in dynamic well control while drilling. This process regularly divides into three basic steps, first kick identification, second kick arrest by making flow out through MPD equipment equal to flow in, and third kick circulation to surface keeping the Bottom-Hole Pressure (BHP) constant, using the Pressure While Drilling (PWD) ECD or the Stand-Pipe Pressure (SPP) as a reference.

To this end, an Influx Management Envelope (IME) developed during the planning phase, establishes the limits for safe dynamic influx management with MPD (Gabaldon et al., 2019). This considers the bit on-bottom (i.e. an active drilling circumstance) at the section's total depth (TD), and also yields the Dynamic Maximum Allowable Annular Surface Pressure (DMAASP) and Static Maximum Allowable Annular Surface Pressure (SMAASP). These values represent the upper dynamic and static pressure limits for the MPD system, to avoid exceeding the formation strength or equipment limits, under drilling and influx control scenarios. For ease of application, the MPD operational matrix employs these single values (Bacon et al., 2015), intended to address the worst-case scenario at the section's TD, instead of a depth-based range of values. Field practice often involves initiating the kick response close to the MPD matrix maximum pressure, such as 80% to 90% of the DMAASP. This tactic aims to minimize influx size by reducing reaction time and obtaining a higher ECD. It helps to limit gas expansion and the increase in flow-out at the Mud Gas Separator (MGS), thereby ensuring safe circulation.

Influx incidents during off-bottom operations are the second most frequent after on-bottom drilling and account for more than a quarter (27%) of the globally recorded influx incidents (Gillard et al., 2022). These include tripping operations (either pulling out-of-hole or running in hole), wiper trips, back-reaming operations, and more. However, the MPD kick management process, operations matrix and IME are developed for drilling circumstances (i.e. with the bit on-bottom), as detailed before (API, 2023). This raises the question: how do these processes apply under off-bottom circumstances? There are several issues to be considered, such as: the mud in the well may now be heavy tripping mud, the gas kick position relative to the bit may be uncertain and already in expansion phase, which may invalidate the flow out equal to flow in strategy to arrest the kick, since the bit is off-bottom, the DMAASP may change due to a reduction in annular friction losses (AFL), a swabbed kick can normally have no kick intensity (KI), which means that the kick can be circulated with minimal pressure, but the gas expansion might be higher than expected.

Lastly, the commonly accepted procedure for handling off-bottom kicks involves running-in-hole (RIH) to total depth (TD) and circulating the kick out of the well. However, current literature lacks evidence of the practical implementation of this process. Several procedural questions arise, such as: (1) Is the well closed during this operation? (2) Is surface pressure bled off after rising due to fluid compressibility? (3) If managed with MPD, are the chokes maintained at a fixed pressure with constant circulation or by balancing flow-out with flow-in? (4) Given potential gas migration, how are references established to circulate the well and remove the kick if it is no longer positioned at TD? (5) If pressure while RIH to TD exceeds MPD limits, or gets too close to the "pipe-light" limit, is it feasible to circulate the well to remove part of the kick? (as an option to bull-heading the well)

This work is first focused on the analysis of how the main kick indicators (e.g. pit volume, MPD flow-out, MPD virtual trip tank) are affected during off-bottom operations, and the identification of the main influence factors. The goal is to minimize false alarms and reduce unnecessary well control procedures.

Secondly, this study analyzes the impact of bit depth on the DMAASP value during off-bottom operations. Traditionally, this calculation assumes the bit is at TD, reflecting a conservative approach (API, 2023). However, this research expands its scope to consider scenarios where the bit may be positioned at the shoe during short trips, which introduces a different operational context compared to encountering a kick at TD. The study will assess pressure limits with the bit positioned at both TD and the shoe depth, while maintaining constant bottom hole pressure (BHP).

Finally, it examines the impact of employing the flow-out equal to flow-in strategy to control and circulate an off-bottom kick, focusing on pressures at critical depths in the well. The study also evaluates the outcomes of using DMAASP and the minimum required pressure to circulate an off-bottom kick, analyzing the effects on pressures and surface flow rates for gas and liquid once the kick reaches the surface (a traditional surface equipment limit for kick circulation). Lastly, it addresses the challenges of running-in-hole to circulate the kick out of the well, aiming to establish a foundation for future procedural development.

Kick Identification during off-bottom operations

MPD technology has demonstrated effectiveness in early kick identification, mainly due to its closed system and the direct measurement of flow out using a Coriolis flow meter. Furthermore, advanced algorithms have been developed to estimate the cumulative volume change (i.e. virtual trip tank or equivalent volume - EQV) by computing the difference and the measured flow out. In almost every case flow in is not directly measured, it is rather computed from an estimated pump output efficiency and a stroke counter (very few offshore installations have the flow in measurement capability by using a flow meter on the system's inlet side). This is complemented with the real-time computation of the deltaflow, which reflects the difference between flow out and flow in.

Thus, while conventional rig pit volume totalizer (PVT) measurements remain the primary kick indicator, integrating MPD features significantly enhances early-stage confirmation of an influx entering the wellbore. However, several changes during off-bottom operations can affect these measurements. For instance, during back reaming operations, Standpipe Pressure (SPP) readings fluctuate as the bit moves upward, which impacts pump efficiency and thus, EQV measurement. Furthermore, adjustments in pump flow rate may be required to operate a reamer or a set of downhole tools, which affect fluid compressibility and fluid levels. Lastly, the shift in downhole and surface (pit) temperatures also generates volume changes.

This analysis aims to anticipate how different drilling conditions versus off-bottom scenarios would affect the PVT and volume totalizer from the MPD system.

Standpipe pressure change, impacting the MPD volume totalizer

The MPD EQV tracks the total volume change in the well. This measurement relies on the difference between flow in and flow out, as described in equations (3) and (4). Flow out is measured directly (2), while flow in is computed based on pump stroke volume, pump speed, and pump efficiency, which is assumed to remain constant at different pump speeds (1).

$$Flow \quad In = Q_{in} = \quad V_{pump\ stroke}\left[\frac{gal}{stk}\right]\omega_{pump}\left[\frac{stk}{min}\right]\eta \quad (where \quad \eta \quad is \quad pump \quad efficiency) \tag{1}$$

$$Flow \quad Out = Q_{out} = \quad MPD \quad Coriolis \quad Reading\left[\frac{gal}{min}\right] \tag{2}$$

$$Deltaflow = \quad \Delta Q = \quad Q_{out} - \quad Q_{in} \tag{3}$$

$$MPD \quad Volume \quad Totalizer = \quad EQV = \quad \int \Delta Q \quad dt \tag{4}$$

However, pump efficiency and, consequently, pump output (Q_{out}) at a fixed speed are not constant values. Field data in Fig. 1 shows that at higher pump pressures, pump efficiency can decrease, leading to a lower-than-expected pump output. If the system does not adjust for this efficiency drop, it can result in significant discrepancies in flow measurements, potentially causing inaccurate assessments of well conditions. For example, data in Fig. 1 indicates a 1000 psi variation in SPP corresponds to a 0.1 gal/stroke change in pump output. Assuming a pump speed of 215 strokes/minute, this shift represents an error of 21.5 gallons/minute or 0.52 bbl/minute. Since the EQV does not account for this efficiency change, over a 10-minute period, this would result in a 5.2 bbl difference. This discrepancy could be either a gain or loss, depending on the initial reference value for pump stroke volume ($V_{pump\ stroke}$) entered into the MPD control system as the rig pump stroke volume input.

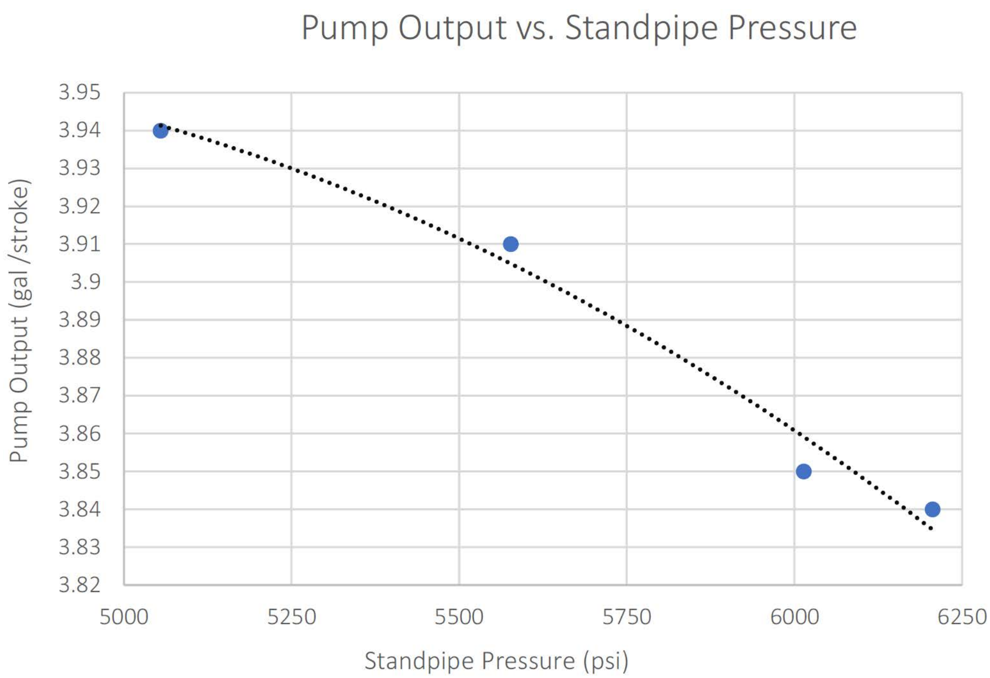

Figure 1—Pump output as a function of Standpipe Pressure (SPP) - The data presented corresponds to a fingerprinting analysis conducted on an actual rig using synthetic based mud (SBM), where the actual pump output was measured at different standpipe pressures.

An additional parameter derived from the EQV is the EQV Rate of Change (EQV RoC), as detailed in Dow et al. (2022). This yields the slope of the EQV curve, which factors out the offset between the real rig pump volume output and the estimated one. However, the error from variable pump efficiency across different pressures and rates remains a known issue. It is vital to thoroughly understand and consider this variability.

Standpipe pressure change, impacting the pit volume totalizer (PVT) measurement

Changes in standpipe pressure (SPP) due to variations in flow rate or bit depth, which influence the pressure profile inside the drillstring, as the MPD system maintains constant pressure in the annulus. These changes in the drillstring pressure profile are reflected in fluid volume changes (i.e. PVT change), due to the fluid system compressibility. This directly impacts a primary kick indicator and requires further consideration to avoid false kick alarms and unnecessary crew reactions.

This study used a transient simulator to analyze the PVT change resulting from adjusting the pump flow rate from 650 gpm to 400 gpm in a 12.25-inch hole section at 20,825 ft, as detailed in Table 1. As shown in Fig. 2, this adjustment reduced the SPP by 2900 psi, causing an average 2655 psi change in the drillstring pressure profile, while maintaining constant BHP with Surface Back Pressure (SBP). As shown in the upper right frame of Fig. 2, the pressure changes after the flowrate changes at 821 min. led to a fluid decompression within the drillstring, resulting in a PVT change reflected after 821 min. The results in Fig. 2 indicate a volume gain of 3.6 bbl for an Oil-Based Mud (OBM) and a volume gain of 3.3 bbl for a Water-Based Mud (WBM) after the pump flow rate is reduced. This effect can also be analytically verified, as shown by equations (5) and (6).

$$Fluid\ \ Bulk\ \ Modulus = \ \ \beta = \frac{1}{compressibility} = \frac{1}{\alpha} = \ \ -V\frac{dp}{dV} \tag{5}$$

$$Volume\ \ Change = dV = -V_{drillstring} dp\ \ \alpha\ \ = \ \ -555.8\ \ bbl\ \left(-2655\ \ psi\right)\ 2.5\ \ \times 10^{-6}\frac{1}{psi} = \ \ 3.7\ \ bbl \tag{6}$$

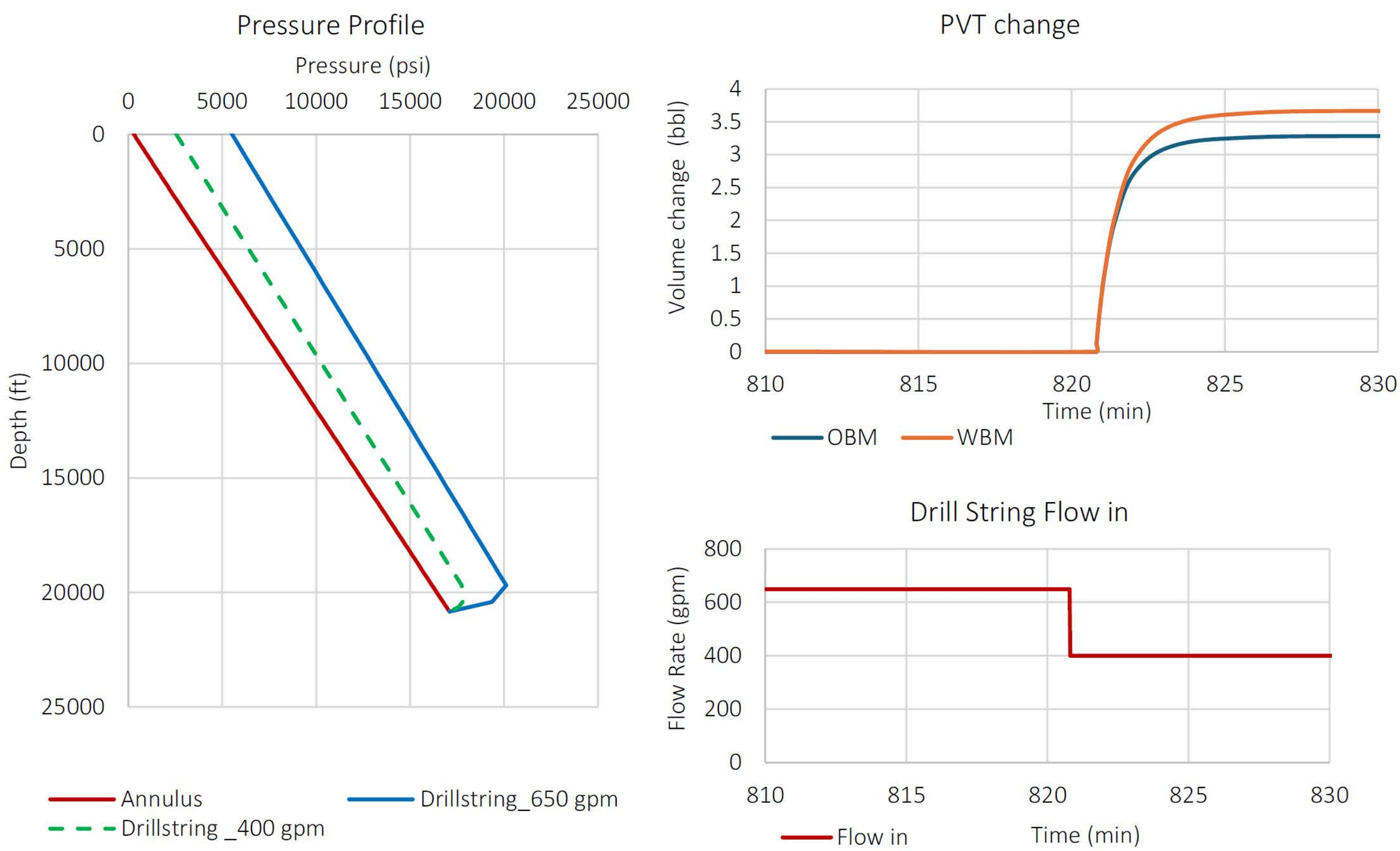

Figure 2—Drillstring and Annulus pressure profile at 650 and 400 gpm, with the bit depth at 20,825 ft (left); pit volume totalizer volume change versus time (upper right); drillstring flow rate versus time.

Table 1—Example deep-water well for transient simulation

Parameter	Values
Water Depth	2,500 ft
Last casing shoe	14″ OD (12.36″ ID) @ 16,000 ft
Hole Size	12.25″ @ 20,825 ft
Drill Pipe	6.625″ OD (5.375″ ID) 40.05#
BHA	Length: 800 ft, OD: 8″
SMW	15.1 ppg
Total Annular Volume	558.8 bbl

Temperature effect in pits tanks

Lastly, it is important to consider the temperature change in the pits and its impact on PVT measurement due to fluid thermal expansion. As shown in Fig. 3, commercial hydraulic software predicted the volume change in a total pit volume of 1450 bbl across different temperatures, at atmospheric pressure (14.7 psi). The results in Fig. 3 indicate a 3.6 bbl increase in volume with a 10°F rise in pit temperature for Water-Based Mud (WBM) and a 4.1 bbl increase for Oil-Based Mud (OBM).

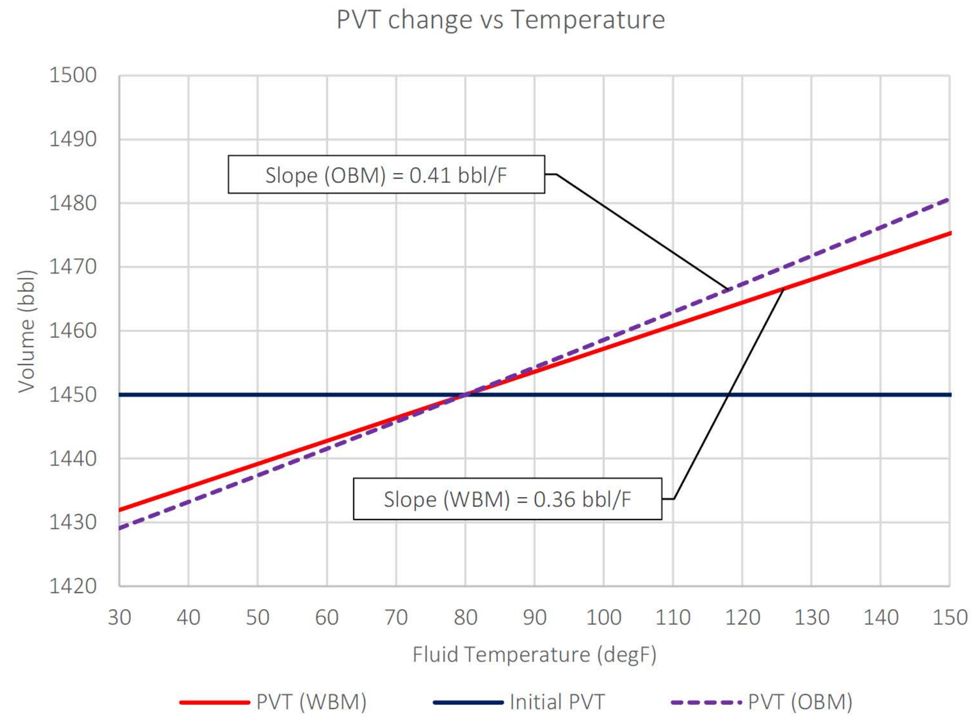

Figure 3—Pit volume thermal expansion for a total pit volume of 1450 bbl at atmospheric pressure (14.7 psi), considering a water-based mud (red line) and an oil-based mud (purple line).

These effects can be significant during circulation after extended periods of static well conditions (due to the fluid temperature increase inside the wellbore), and in regions with significant ambient temperature fluctuations, depending on the geographical location of the rig. And thus, need to be taken in consideration to further avoid any false kick alarms.

Pressure limits change with bit depth

Pressure limits (MAASP and DMAASP) calculation for MPD

First, revisiting key terminology regarding the maximum pressure allowed when designing an MPD job is necessary. As previously mentioned, both the MAASP and DMAASP are determined during the MPD job design and constitute the most critical limits for the MPD matrix. The initial approach is to calculate these values considering no influx in the well (single-phase conditions), or similarly, considering the influx below the shoe (or weak point). These maximum values are then used as a baseline to build the IME and MPD Operations Matrix, verifying that the influx can be safely circulated out while ensuring that the maximum pressure, maximum gas, and maximum liquids remain within safe limits.

The MAASP is used for static conditions (i.e. there is no pump flow rate through the drillstring), and it determines the maximum surface pressure that the well can withstand before reaching the formation pressure limit at the weak point (WP) of the exposed formation - this is regularly considered as the Formation Integrity Test (FIT) or Leak Off Test (LOT) value at the shoe, but it can also consider other reference depths based on the design criteria. This value is determined as equation (7), where *ρ_(ESD @ WP)* is the equivalent static density (ESD) at the weak point, ρ_{CL} is the density equivalent for the cuttings load, $D_{TVD@AP}$ is the true vertical depth (TVD) (in this example AP = TD) at the section's TD, and CF is the conversion factor for the unit system (which also considers the gravitational force).

$$P_{MAASP} = \left(\rho_{FIT} - \rho_{ESD\,@\,WP} - \rho_{CL}\right) D_{TVD@AP} \; CF \tag{7}$$

Cuttings load (CL) is regularly included in this calculation as it results in a lower MAASP, acting as a safety factor when the well is clean. However, in cases where the cutting load is significantly high (e.g. top-hole sections where it can reach 0.3-0.4 ppg), since the SBP for the no cuttings load case might be above the SBP limit for the cuttings load case, it may be necessary to elaborate a matrix with and a matrix without cuttings load. This is particularly important for off-bottom operations, since the well must be cleaned before proceeding with the subsequent steps.

The DMAASP is used for dynamic conditions (i.e. where there is pump flow rate through the drillstring), and it determines the maximum pressure that can withstand before reaching the formation pressure limit at the weak point (WP) of the exposed formation. This value is determined as equation (8), where ECD @ WP is the equivalent circulating density (ECD) at the weak point.

$$P_{DMAASP} = \left(\rho_{FIT} - \rho_{ECD@WP} - \rho_{CL}\right) D_{TVD@AP} \; CF \tag{8}$$

The DMAASP determined with equation (8) ensures the weak point pressure limit is not exceeded in dynamic conditions, but does not ensure that the condition is met if the well needs to be shut-in and the system performs a pressure ramp. To satisfy this condition, the DMAASP with the ability to shut in (DMAASP*) is computed, which represents the maximum pressure that can be applied with the pumps on, while still retaining the ability to perform a connection ramp (e.g. for an assisted shut-in keeping the target ECD at the anchor point) without exceeding the weak point pressure limit. This case is determined as equation (9), where P_{AFL} are the annular friction losses at the anchor point (AP).

$$P_{DMAASP*} = \left(P_{MAASP} - P_{AFL}\right), \quad valid \;\; when \;\; the \;\; AP \;\; is \;\; below \;\; the \;\; WP$$

An important note about equations (8) and (9) is that if the AP is below the weak point, the DMAASP* will be smaller than DMAASP. In case the AP is above the weak zone, the DMAASP* will be higher than DMAASP, and thus this last one needs to be considered as the limit.

MPD connection ramp design and pressure limits

MPD systems maintain constant BHP at the AP for a range of flow rates, including during drill pipe connections where there is no flow rate. To achieve this, the system responds to a ramp that correlates flow rate with SBP. Regardless of the specific system used, all MPD systems adhere to this principle. Some systems calculate annular friction losses (AFL) in real-time based on drilling conditions, others use a pre-loaded ramp (SBP vs. Flow Rate), which is manipulated and updated during execution based on fingerprinting results and actual ECD values.

Based on this concept, the following section demonstrates how pressure limits and the MPD connection ramp shape change with bit depth, considering the off-bottom scenario. This analysis raises questions about how drilling-imposed limits can impact off-bottom operations if not properly updated.

Table 2 below details the 3 cases considered for MPD SBP ramp, MAASP, DMAASP and DMAASP* determination, where the main difference is the hole section (Case A is a 12.25″ hole section, while Case B and C are 14.5″ hole sections) and the pipe in the well (Case A and B are drilling BHAs, while Case C is a liner).

Table 2—Case study wells for MPD ramp, MAASP and DMAASP scenarios

Parameter	Values	Case A	Case B	Case C
Mud Type	WBM	x	x	x
Water Depth	2,500 ft	x	x	x
Last casing shoe	14″ OD (12.36″ ID) @ 16,000 ft	x	x	x
Drill Pipe	6.625″ OD (5.375″ ID) 40.05#	x	x	x

Hole Size	12.25″	x		
Hole Size	14.5″		x	x
Simplified BHA	Length: 800 ft, OD: 8″	x	x	
Liner	Length: 5,320 ft, OD: 9.625″			x
TD	20,825 ft	x	x	x
SMW	15.1 ppg	x	x	x
EMW Target	15.8 ppg	x	x	x
Anchor Point	TD	x	x	x
FIT	16.2 ppg	x	x	x
Weak Point	Shoe Depth	x	x	x

Case A - 12.25" Hole Section (HS), Bit at TD and at the previous shoe. First, the values for Case A are determined with the bit at TD, a 15.8 ppg equivalent mud weight (EMW) set-point (SP) at TD, and a 16.2 ppg weak point limit at the shoe. Figure 4 presents the SBP values for a range of pump flow rates with the bit at TD. The SBP_Bit@TD values include the SBP ramp for a 15.8 ppg EMW SP (dark blue solid line), DMAASP (light blue solid line), and DMAASP* with the ability to shut in (dashed dark blue line), and MAASP (red dashed line). The green shaded area represents the available SBP window, delimited between the SBP necessary to achieve the EMW target and the DMAASP*, resulting in an approximately 250 psi actionable range for the MPD system.

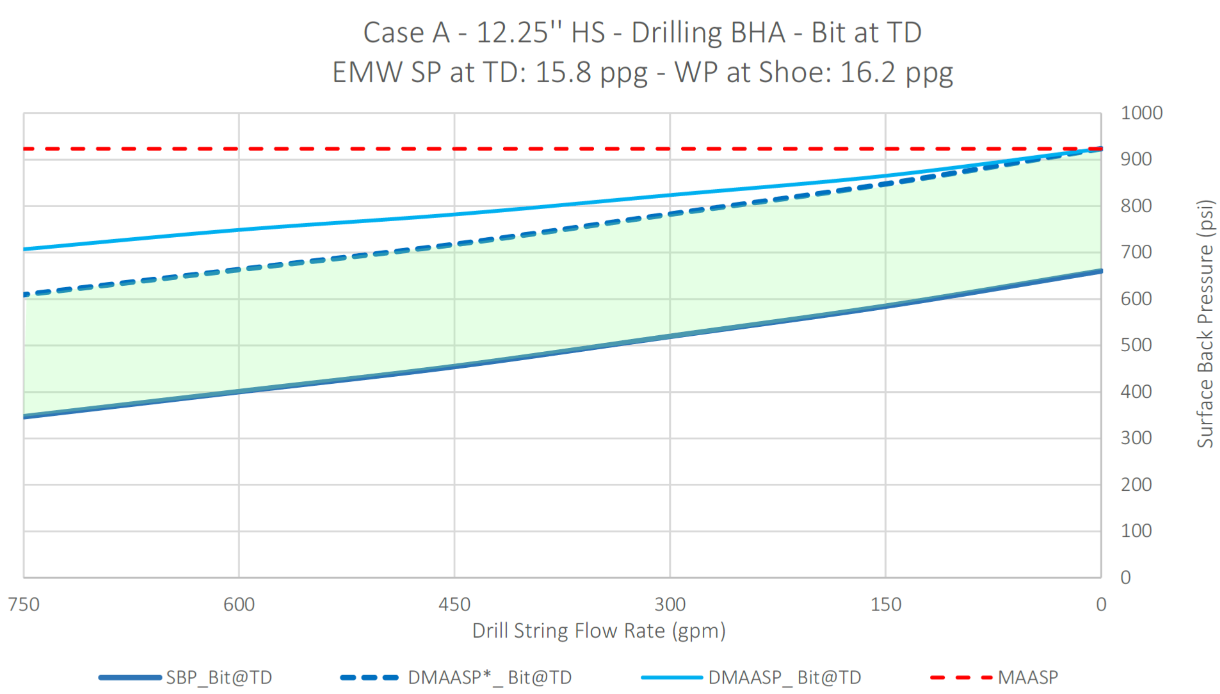

Figure 4—Case A with Bit @ TD, SBP values for a range of pump flow rate. Results for SBP ramp (dark blue solid line) for a 15.8 ppg ECD @ TD, DMAASP (light blue solid line) and DMAASP* with the ability to shut in (dashed dark blue line) and MAASP (red dashed line) for a weak point limit at the shoe of 16.2 ppg. The green shaded area represents the available SBP window for the MPD system at TD.

However, if the bit is moved upwards after reaching TD (e.g., a wiper trip, a short trip to the shoe, reaming, or pumping out of hole), the SBP required to maintain the target ECD at TD will increase. This is due to the reduction in AFL at the bit as drill pipe is removed from the hole. Considering the bit at the shoe, as shown in Fig. 5, an additional 100 psi at 600 gpm is needed to generate the target ECD compared to the bit at TD values. The required SBP curve has now shifted higher (light brown solid line) compared to the SBP at TD (dark blue solid line) due to the lower AFL at the bit.

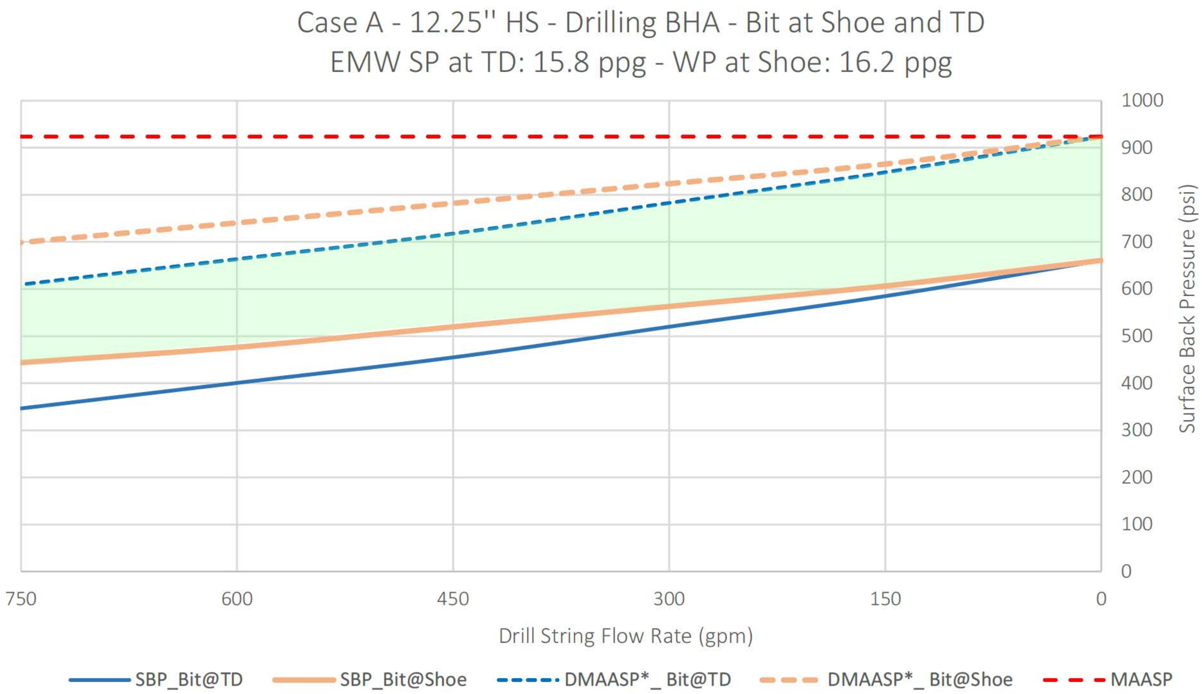

Figure 5—Case A with Bit @ Shoe and TD, SBP values for a range of pump flow rate. Results with bit @ Shoe for SBP ramp (solid light brown) for a 15.8 ppg ECD @ TD, DMAASP* with the ability to shut in with bit @ Shoe (light brown dashed line), DMAASP* with the ability to shut in with bit @ TD (dark blue dashed line) and MAASP (red dashed line) for a weak point limit at the shoe of 16.2 ppg. The green shaded area represents the available SBP window for the MPD system combining the required SBP at the Shoe, with the original DMAASP* (not updated for current conditions).

The green shaded area now shows the updated SBP window, clearly indicating a reduction in the available range since the original DMAASP* at TD has been kept in place. This is the regular practice in the field, where the MAASP, DMAASP, and DMAASP* are maintained throughout the drilling section and only updated if the drilling mud weight (MW) is changed. However, according to equation (10) below, the DMAASP* with the bit at the shoe (light brown dashed line) is higher than with the bit at TD. This is due to the reduction in AFL at the bit when positioned at the shoe. Therefore, if a trip is conducted upwards from TD while maintaining the limits designed for TD, the SBP window is incorrectly limited (as highlighted in Fig. 5).

$$\text{Since} \quad P_{DMAASP*} = P_{MAASP} - P_{AFL}, \quad \text{and} \quad P_{AFL_{Shoe}} < P_{AFL_{TD}}, \quad \text{then} \quad P_{DMAASP*} > P_{DMAASP*\,TD} \tag{10}$$

When the pressure limits are kept at the TD values, as is common practice, a kick with the bit off-bottom (e.g., a swabbed kick during a trip) will result in an incorrectly limited SBP range that is lower than what is actually available. This limitation restricts the actionable range for the MPD system. This principle applies to any bit position between TD and the surface, with all the pressure lines shifting upwards. As the bit approaches the surface, the SBP line moves closer to a horizontal line similar to the connection pressure, and the DMAASP and DMAASP* align more closely with the MAASP due to lower AFL generation. Although this is a theoretical concept since no trip would be planned with an underbalanced mud weight all the way to the surface, it closely approximates tripping out of a hole to the subsea blowout preventer (SSBOP) and then positioning a riser cap, as friction in the riser is negligible.

Case B - 14.5" Under-Reamed Hole Section, Bit at TD and at the previous shoe. Additional analysis was conducted to Case B in Table 2, which is the same as Case A but now the section is under-reamed

(UR) to 14.5″. Fig. 6 presents the SBP values for a range of pump flow rate for Case B, considering both the bit at the shoe and the bit at TD.

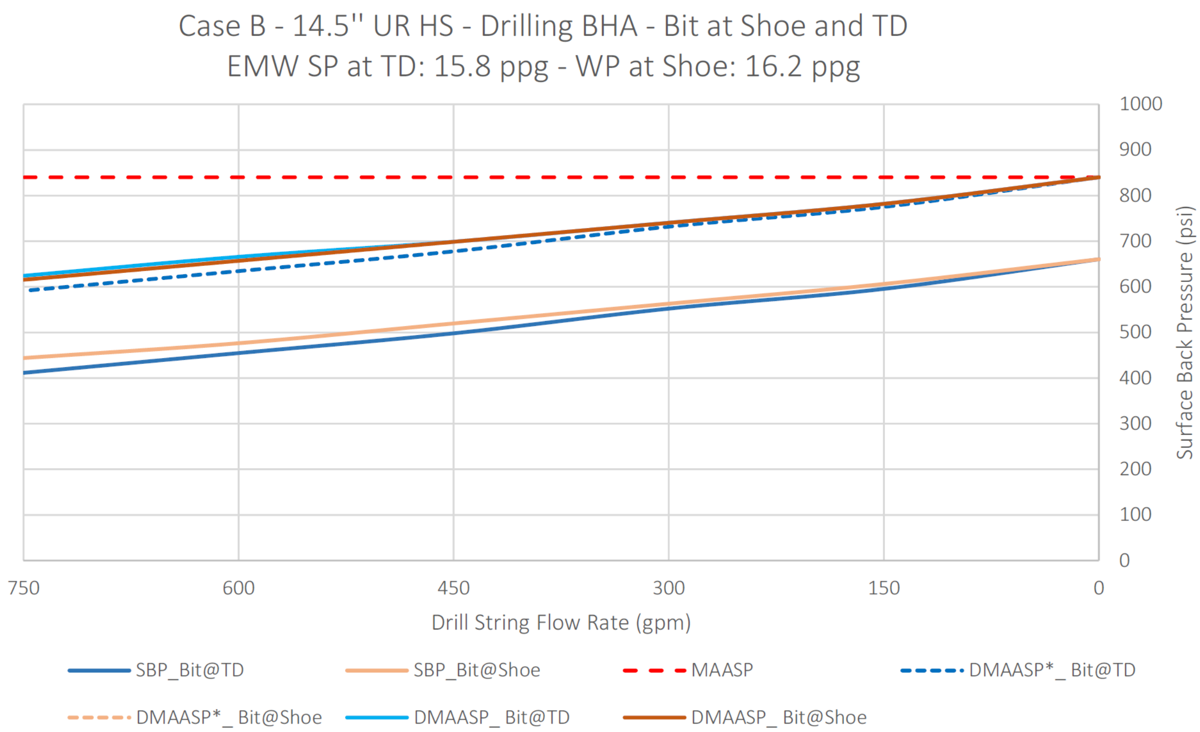

Figure 6—Case B with Bit @ Shoe and TD, SBP values for a range of pump flow rate. Results for SBP ramp (bit at the shoe solid light brown line, bit at TD solid dark blue line) for a 15.8 ppg ECD @ TD, DMAASP* with the ability to shut in (bit at the shoe light brown dashed line, bit at TD dark blue dashed line), DMAASP (bit at the shoe dark brown solid line, bit at TD light blue solid line) and MAASP (red dashed line) for a weak point limit at the shoe of 16.2 ppg.

As anticipated, the AFL are lower since the hole section is now under-reamed to a bigger diameter. This effect results in a lower SBP range between the TD and at the shoe values for SBP for Case B.

Case C - 14.5" Under-Reamed Hole Section, 9.875" Liner run, Bit at TD and at the previous shoe. A final analysis was conducted for Case C, now running a 9.875″ liner in the 14.5″ UR HS, which revealed different AFL behavior compared to the previous Case B with drill pipe. Fig. 7 again presents the SBP values for a range of pump flow rates with the bit at TD and at the shoe for Case C. The green shaded area represents the SBP range with the bit at TD, delimited between the SBP ramp and the DMAASP*, while the light brown shaded area represents the SBP range when the bit is at the shoe.

As illustrated in Fig. 7, the SBP lines for the liner at TD and at the shoe are now inverted compared to previous cases. Since this is a 14.5″ Under-Reamed HS, the AFL is higher when the liner is inside the previous casing (14″ OD, 12.36″ ID) at 16,000 ft than when the liner is fully positioned in the 14.5″ open-hole section. Therefore, a lower SBP is required to achieve the target ECD when the liner is at the shoe compared to when the liner is located at TD. This may seem contradictory but is clearly explained by the variation in annulus clearance depending on the liner's position.

Consequently, in this scenario, using DMAASP* calculated with the liner at TD is not the most conservative approach, as it may exceed the formation pressure limits when the liner is at the shoe or just above TD. In such a case, the pressure window that satisfies both scenarios (liner at shoe and at TD) is the intersection of both areas highlighted in Fig. 7.

Therefore, as illustrated by Cases A, B, and C, maintaining updated pressure limits (MAASP, DMAASP, and DMAASP*) during off-bottom operations is of utmost importance. Keeping the TD-referenced values can result in incorrectly set SBP ranges for the MPD system and may mistakenly be deemed conservative when they might actually surpass the formation pressure limits, as shown in Case C.

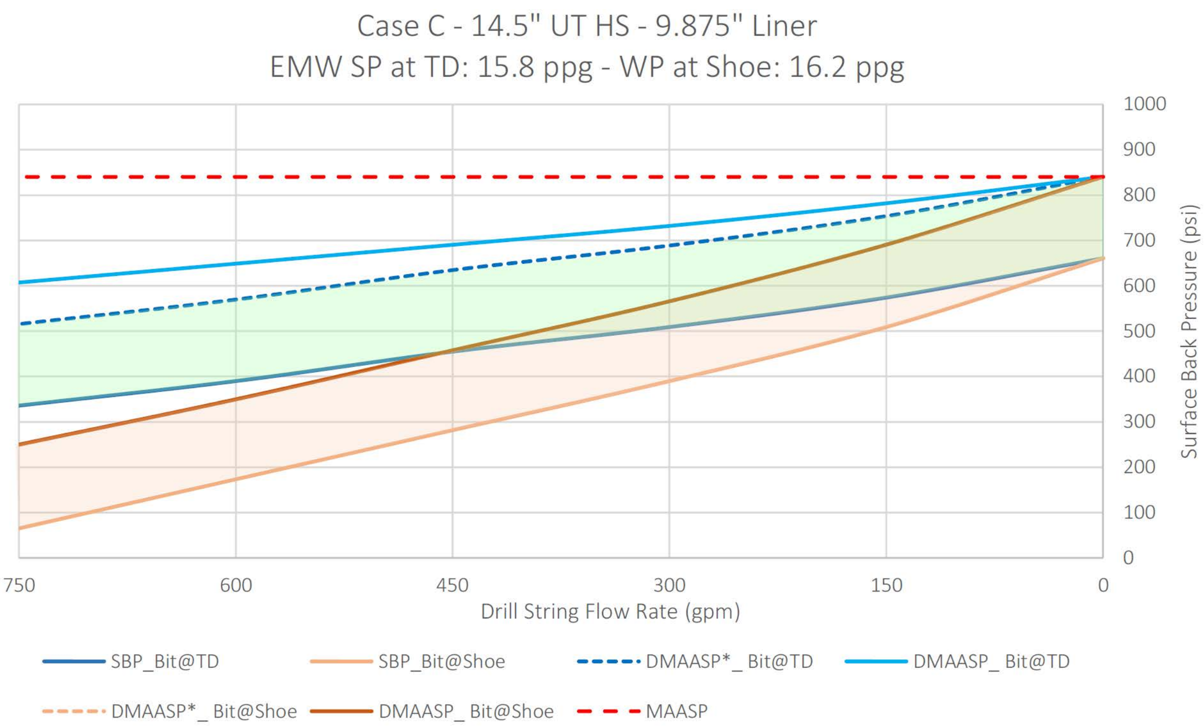

Figure 7—Case C with Bit @ Shoe and TD, SBP values for a range of pump flow rate. Results for SBP ramp (bit at the shoe solid light brown line, bit at TD solid dark blue line) for a 15.8 ppg ECD @ TD, DMAASP* with the ability to shut in (bit at the shoe light brown dashed line, bit at TD dark blue dashed line), DMAASP (bit at the shoe dark brown solid line, bit at TD light blue solid line) and MAASP (red dashed line) for a weak point limit at the shoe of 16.2 ppg. The green shaded area represents the SBP range with the bit at TD, delimited between the SBP ramp and the DMAASP*, the light brown shaded area represents the SBP range when the bit is at the shoe.

Arresting the influx with MPD

The flow out equal to flow in strategy

When detecting a kick while drilling ahead, the first step is to apply SBP to stop the influx, aiming to make the Coriolis flow out equal to flow in. This indicates that the formation influx into the wellbore has ceased. Subsequently, the influx circulation process begins, mimicking the first circulation of the driller's method. During this process, the SBP is adjusted to maintain the ECD or SPP at the reference value observed when the influx was arrested (i.e., when flow in equals flow out).

However, dealing with an off-bottom kick introduces greater complexity. In such instances, influx can occur due to various factors, including the swabbing effect during upward pipe movement, inadvertent SBP reduction causing BHP decrease, or BHP drop from fluid expansion due to temperature changes. These factors complicate the precise identification of downhole conditions. During pumping out or reaming operations, gas may inadvertently circulate up the annulus and only be detected once it has reached a depth where it begins to expand exponentially and break out of solution. In these cases, the conventional flow-out-equals-flow-in strategy may not be as effective as during drilling. This section aims to examine the outcomes of using SBP to control flow-out (i.e., flow-out-equals-flow-in strategy), similar to handling a drilling kick, but now focusing on a tripping scenario where the influx is detected near the surface and already undergoing exponential expansion.

Fig. 8 illustrates the use of a commercial multiphase simulator to model a 10 bbl gas kick intentionally taken and brought to the surface while maintaining a constant BHP at a target ECD of 15.8 ppg, using the

Case A well from Table 2. As the gas front approaches 3,000 ft from the surface, the Coriolis flow-out readings begin to significantly diverge from the flow-in around the 120-minute mark, indicating exponential gas expansion (since it is WBM, the gas always remains out of solution). At this point, SBP is increased in 100 psi increments to try to arrest the flow out. Results in Fig. 8 show that leveling out the Coriolis flow is impossible, regardless of the applied pressure, because the gas is already in the expansion phase of the circulation. The additional SBP raises both bottom hole pressure and shoe pressure, with significant overbalance. The reduction in flow out is only temporary, caused by gas compressibility. After this transient phase, the flow out returns to the previous value and continues to rise as the gas is circulated.

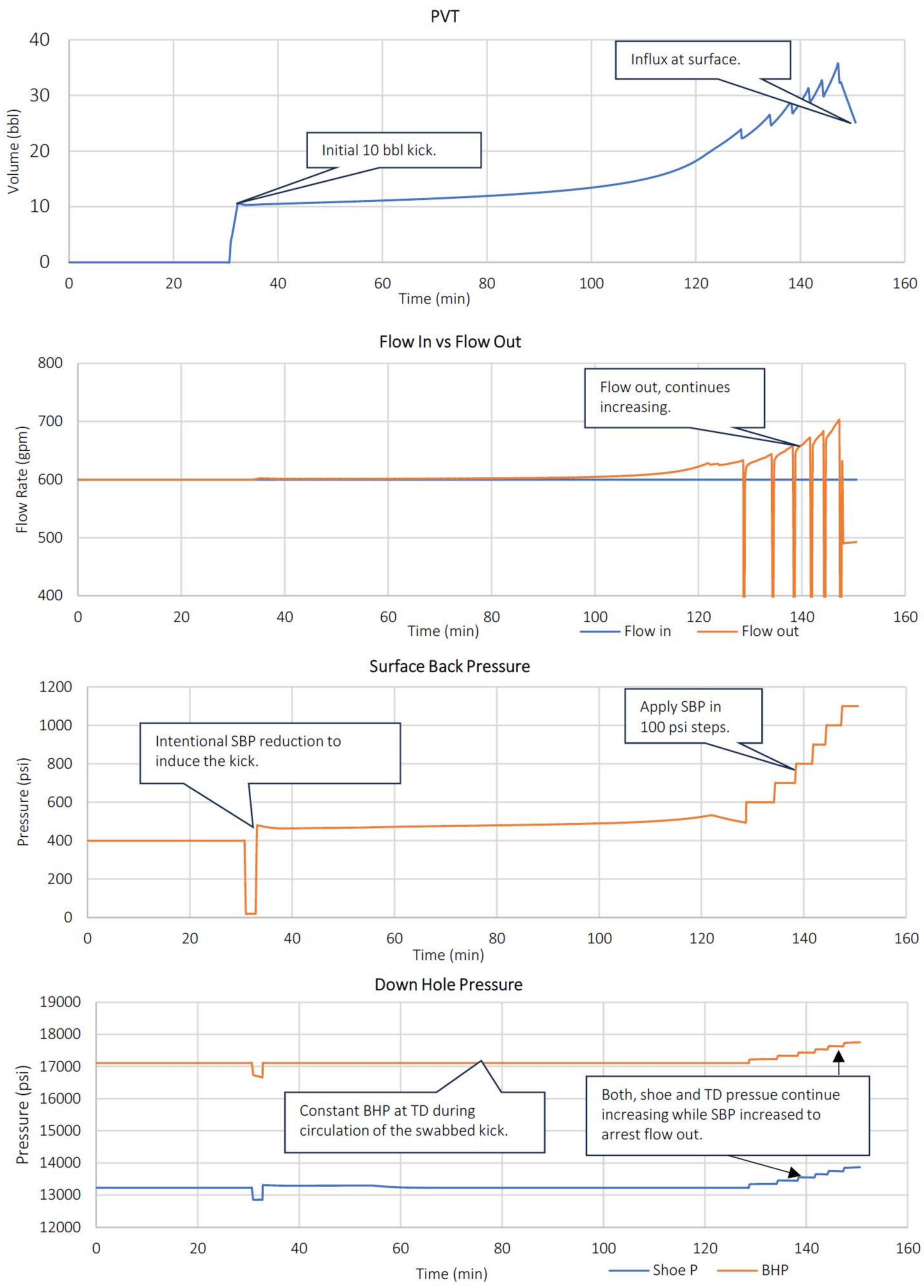

Figure 8—Swabbed kick circulation in Case A well, using the flow-out-equals-flow-in strategy until the kick reaches the surface. Once the kick is over 3,000 ft and getting closer to the surface (around the 120-minute mark), it starts breaking out of solution and exponentially expanding, which increases the flow out. Increasing the SBP will no longer be able to control the flow out, and it will result in a substantial increase in BHP, both at TD and at the shoe.

The previous case illustrates the need for additional references when controlling an off-bottom kick. In such scenarios, since leveling the flow out is not feasible, it becomes necessary to establish a reference downhole pressure and maintain it, similar to the circulation phase of the driller's method.

Kick circulation, how much SBP is enough?

As previously mentioned, when a kick is detected while drilling, the common practice is to raise the SBP to 80 to 90% of the DMAASP*. This strategy ensures a fast reaction time and smaller influx size, quickly compensating for the kick intensity (KI) caused by the difference between the new pore pressure and the current EMW. However, during off-bottom operations, no additional formation or reservoir is being drilled to justify an increase in pore pressure. Therefore, kicks in these circumstances are mainly due to the accidental lowering of BHP (e.g., swabbed kicks) and have a lower pore pressure than the current EMW. Hence, the KI is zero in most cases, and the main purpose of the SBP is to counteract the loss of hydrostatic pressure due to the formation influx. Consequently, we must consider whether the 90% of the DMAASP* strategy remains effective in these cases or if it is overly conservative.

The previous hypothesis is evaluated using simulated gas kicks in a commercial multiphase simulator. Two reference cases are defined based on Case A from Table 2, with different kick control and circulation strategies:

- Case D: the kick is arrested with the minimum SBP required to achieve the EMW value before the influx (the predefined ECD or BHP, used while drilling).
- Case E: the kick is arrested with the maximum pressure allowed in the MPD operations matrix, 100% of the DMAASP* for this case.

In both cases, the kicks are circulated maintaining constant BHP with the same target ECD of 15.8 ppg, following the first circulation of the driller's method. The analysis will focus on kick circulation limiting factors, such as the maximum SBP achieved during circulation and the maximum liquid flow-out rate, both of which are limiting factors included in the IME design.

Maximum kick circulation SBP

Fig. 9 shows the simulation results for surface back pressure for various influx volumes (similar to an IME results), comparing the initial and maximum SBP during kick circulation for Case D (using the minimum required SBP) and Case E (using the DMAASP* for kick arrest). In all cases, the kick intensity (KI) was set to zero, and the kicks were induced by intentionally reducing the SBP over a defined period, momentarily lowering the EMW. The solid lines indicate the SBP required for kick arrest (initial SBP), and the dashed lines show the maximum SBP achieved during kick circulation to the surface. Both cases consider the kick already above the bit.

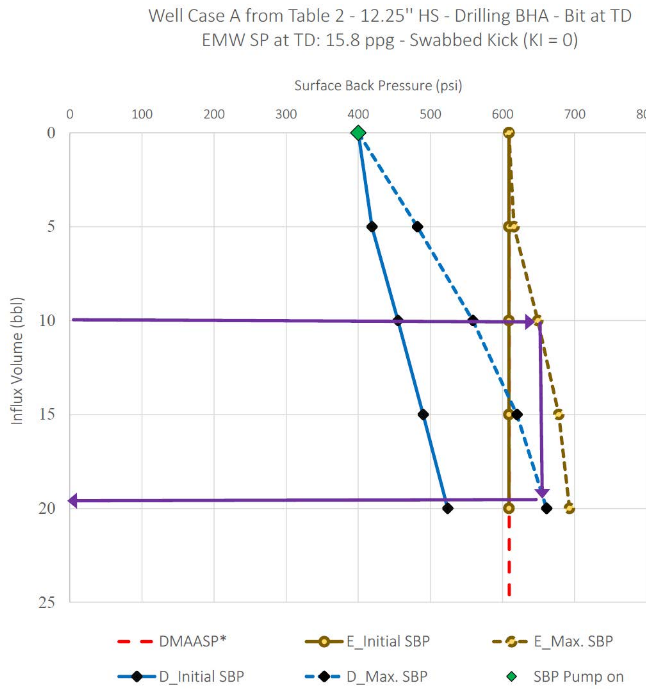

Figure 9—Surface back pressure for various influx volumes is illustrated in this plot, comparing the initial and maximum SBP during kick circulation for Case D (using the minimum required SBP) and Case E (using the DMAASP* for kick arrest). The solid lines indicate the SBP required for kick arrest (initial SBP), and the dashed lines show the maximum SBP achieved during kick circulation to the surface. The arrows indicate that the maximum SBP achieved for a 10 bbl influx in Case E is equivalent to the SBP reached when circulating a 20 bbl kick in Case D. This demonstrates that employing the DMAASP* strategy imposes a limitation on kick size, even though there is actually more capacity for kick circulation.

The arrows depicted in the plot illustrate that the maximum SBP achieved for a 10 bbl influx in Case E equals the SBP attained when circulating a 20 bbl kick in Case D. This highlights that adopting the DMAASP* strategy not only leads to higher SBP but also imposes a restriction on kick size, despite there being ample capacity for kick circulation (twice the capacity in this instance).

An important observation is that the Case D curves can shift along the SBP axis (either to the right or left), contingent upon the initial SBP value (green diamond). However, the relationship between initial SBP and SBP increment with kick size remains consistent, as the required SBP primarily compensates for kick hydrostatic loss. Therefore, this curve can be adjusted along the SBP axis based on the initial SBP, even in static scenarios.

Another important observation is that during circulation, the DMAASP* will eventually be exceeded due to gas expansion once the kick is above the shoe. However, the BHP and shoe (or weak point) pressure are maintained constant and below the limit pressure throughout the entire circulation process. This concern must be adequately discussed with the drilling team when establishing MPD pressure limits.

Maximum liquid flow-out during kick circulation

Fig. 10 shows the liquid and gas flow rate handling tolerance, comparing between Case D (using the minimum required SBP) and Case E (employing the DMAASP* for kick arrest). In all cases, the kick intensity (KI) was set to zero, and the kicks were induced by intentionally reducing the SBP over a defined period, momentarily lowering the EMW. Solid lines represent maximum gas flow rates, while dashed lines depict maximum liquid flow rates during kick circulation to the surface.

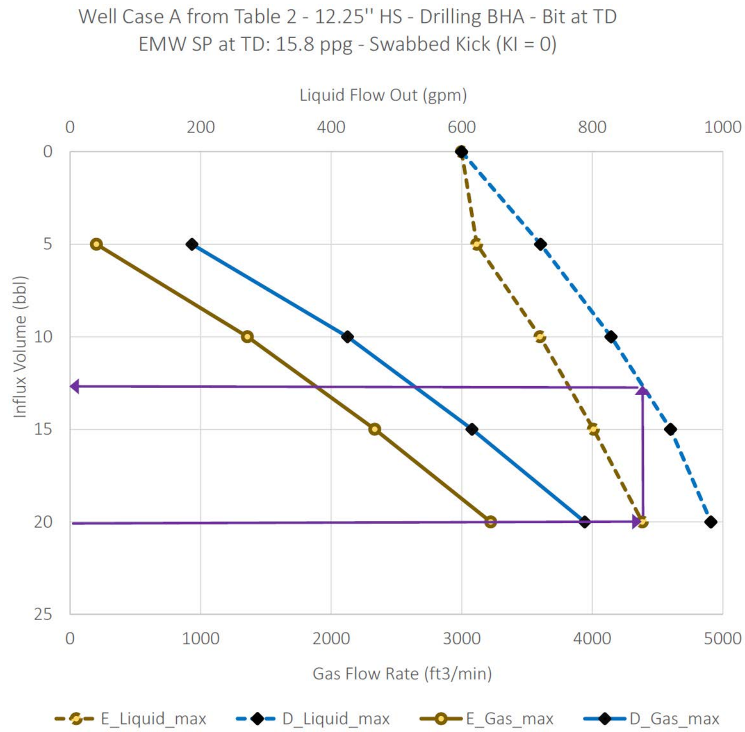

Figure 10—Maximum liquid and gas flow rates for various influx volumes, comparing values between Case D (using the minimum required SBP) and Case E (employing the DMAASP* for kick arrest). Solid lines represent maximum gas flow rates, while dashed lines depict maximum liquid flow rates during kick circulation to the surface. Arrows highlight that the maximum liquid flow rate achieved with a 20 bbl influx in Case E equals the liquid flow rate attained when circulating a 13 bbl kick in Case D. This underscores the advantage of employing the DMAASP* strategy in managing surface flow rates, constrained by the rig's mud gas separator capacity.

Arrows emphasize that the maximum liquid flow rate achieved with a 20 bbl influx in Case E matches the liquid flow rate achieved when circulating a 13 bbl kick in Case D. This underscores the advantage of employing the DMAASP* strategy in managing surface flow rates, constrained by the rig's mud gas separator capacity. This effect applies to both gas and liquid flow rates, with the minimum SBP strategy resulting in higher flow rates, thereby limiting the manageable kick size. This limitation may become more pronounced in larger hole sizes where higher circulation flow rates are used.

This phenomenon can also be explained using the single-bubble equations (15) and (16) derived below. Assigning point 1 as bottom-hole and point 2 as surface, the liquid flow out as the gas bubble circulates to the surface is detailed in equation (11).

$$Q_2 = Q_{pump} + \Delta Q_{gas} \tag{11}$$

Then, the flow rate change due to gas expansion ΔQ_{gas} is as described in equation (12). Using the Ideal Gas Equation of State (13) , the gas volume at surface V_2 is determined as equation (13), where subscript 1 are bottom-hole values, and subscript 2 are surface values. Then the change in gas volume ΔV_{gas} as the bubble migrates from bottom-hole to surface can be determined from equation (14). This illustrates that a lower SBP at the surface P_2, given the same initial BHP P_1, results in a higher change in gas volume ΔV_{gas}.

$$\Delta Q_{gas} = \frac{\Delta V_{gas}}{\Delta t} \quad , \quad where \quad \Delta t = \frac{V_{anular}}{Q_{pump}} \quad then \quad \Delta Q_{gas} = \frac{\Delta V_{gas}}{V_{annular} / Q_{pump}} = \frac{\Delta V_{gas}}{V_{annular}} Q_{pump} \tag{12}$$

$$Ideal \quad Gas \quad Equation \quad of \quad State \qquad P_1 V_1 = P_2 V_2 \quad , \quad then \quad V_2 = \frac{P_1}{P_2} V_1 \tag{13}$$

$$\Delta V_{gas} = V_2 - V_1 = \frac{P_1}{P_2} V_1 - V_1 = \left(\frac{P_1}{P_2} - 1 \right) V_1 \tag{14}$$

Then, by substituting V_{gas} from equation (14) into equation (12), we derive equation (15) for the change in liquid flow rate due to gas expansion. Finally, substituting equation (15) into equation (12), we obtain equation (16) for the surface flow rate during gas circulation.

$$\Delta Q_{gas} = \left(\frac{P_1}{P_2} - 1\right)\frac{V_1}{V_{annular}} Q_{pump} \tag{15}$$

$$Q_2 = Q_{pump} + \left(\frac{P_1}{P_2} - 1\right)\frac{V_1}{V_{annular}} Q_{pump} = \left[\left(\frac{P_1}{P_2} - 1\right)\frac{V_1}{V_{annular}} + 1\right] Q_{pump} \tag{16}$$

Both equation (15) and (16) show that a lower SBP at the surface P_2, for the same initial BHP P_1, result in higher liquid flow rate change and higher overall liquid flow rate out.

For demonstration purposes, we consider pump flow rate Q_{pump}, wellbore annular volume $V_{annular}$, downhole gas volume V_1, and bottom-hole pressure P_1 as fixed inputs (detailed in Table 3), taken from Case A from Table 2.

Table 3—Wellbore Data for Gas Expansion Case

Parameter	Value	Unit
Wellbore annular volume $V_{annular}$	3889	Bbl
Downhole gas volume V_1	10	Bbl
Bottom-hole pressure P_1	17110	Psi
Pump flow rate Q_{pump}	800	gpm
Bottom-Hole Temperature T_1	237	°F
Surface Temperature T_2	80	°F

Then, as illustrated in Fig. 11, reducing the SBP P_2 in equation (15) results in a greater increase in flow rate due to gas expansion Q_{gas}, thereby increasing the flow out Q_2 as the gas is circulated, as shown in equation (16).

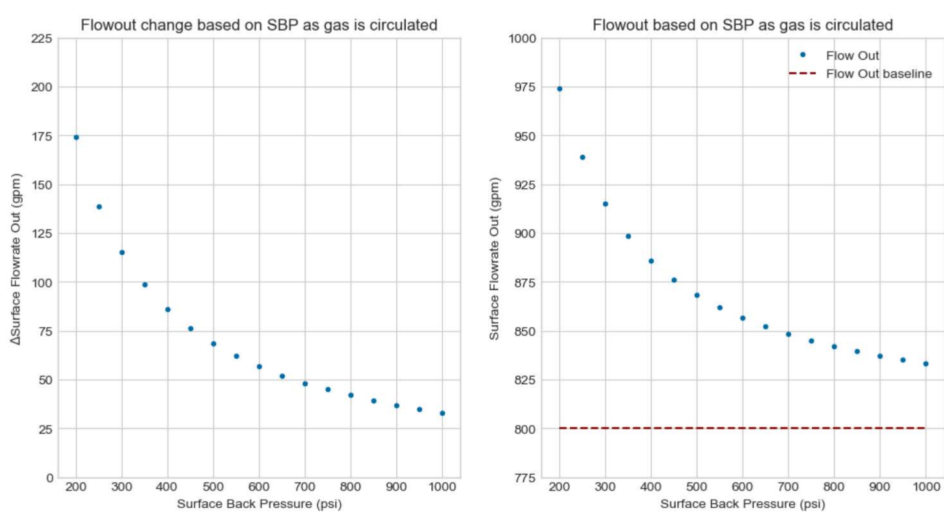

Figure 11—Change in Surface Flow Rate Out due to gas expansion at different SBP. As surface pressure is reduced, the increase in flow out will be higher, as shown by the lower SBP values.

Appendix B shows the updated equations and results obtained from the Real-Gas Equation of State.

Tripping back to bottom after detecting the kick

Upon detecting a kick, the standard procedure involves tripping back to total depth (TD) and initiating circulation to ensure the well is thoroughly cleaned and free of gas. However, several factors influence the ultimate success of this operation and require careful consideration. These factors are outlined below.

Strip in hole with a closed well (no flow out)

At first glance, stripping back to TD with a closed well may seem the safest option, since it ensures no additional influx is taken. However, this approach requires careful consideration of the pressure increase due to fluid compressibility and gas migration, especially when the required gas expansion is restricted. This combination affects the annular pressure profile as the drillstring is lowered to TD, pushing pressures close to the established limits. An alternative option is to lower the pressure once a predefined SBP threshold is reached.

For illustration, we consider Case A from Table 2, with the bit positioned at the shoe at 16,000 ft. We calculate the surface pressure increase after stripping in hole a single 90 ft triple stand, considering a 10 bbl dry gas kick at the bottom of the well. The drillpipe is a 6.625″ OD (5.375″ ID) 40.05# close-ended pipe (with a non-return valve), with a displacement of 0.042 bbl/ft. Table 4 shows the data used for the calculation and the expected surface pressure increase.

To compute the pressure increase, the effective bulk modulus for the system, and its inverse the compressibility α_C were used. Following Aarsnes et al. (2016), the effective bulk modulus for two different phases under the same pressure, considering an ideal isothermal gas, is defined by equations (17) to (19). The gas fraction is denoted asα_G, and the bulk modulus for an isothermal ideal gas equals the pressure p (as defined in Appendix A). The effective modulus for the well fluids is defined by equation (20), and the surface pressure change is defined by equation (21).

$$Bulk\ Modulus = \beta = -V\frac{dp}{dV} \tag{17}$$

$$\beta = -\left(V_1 + V_2\right)\frac{dp}{dV_1 + dV_2} = \frac{\left(V_1 + V_2\right)}{\frac{V_1}{\beta_1} + \frac{V_2}{\beta_2}} \tag{18}$$

$$\beta = \frac{\beta_L p\left(x_j\right)}{p\left(x_j\right)\left(1-\alpha_G\left(x_j\right)\right) + \beta_L \alpha_G\left(x_j\right)} \tag{19}$$

$$\beta = \frac{1}{\alpha_C} = \frac{L}{\int\left[\frac{\alpha_G}{p} + \frac{1-\alpha_G}{\beta_L}\right]dx} \tag{20}$$

$$Surface\ \ Pressure\ \ Change\ = dp = -\beta\frac{dV}{V} \tag{21}$$

Table 4—Case A well, surface pressure increases after stripping in hole a 90 ft triple stand

Parameter	Value
Drill pipe	6.625″ OD (5.375″ ID) 40.05# close ended (with an NRV)
DP displacement	0.0426 bbl/ft
90 ft stand displacement	3.84 bbl
Mud Type	WBM
Mud Density	15.1
Mud Compressibility	$1.88\times10^{-6}\frac{1}{psi}$
Kick Volume	10 bbl

Parameter	Value
Gas Specific Gravity	0.55
Reservoir Pressure	17110 psi
Reservoir Temperature	237 °F
Gas Density	2.45 ppg
Kick Height	48.96 ft
Annular Volume	3190 bbl
Volume Change	-3.84 bbl
Effective Bulk Modulus	$4.97 \times 10^5\ psi$
Effective Compressibility	$2.01 \times 10^{-6} \frac{1}{psi}$
Surface Pressure Change	**+598 psi**

The results indicate that stripping a 90 ft stand into the well results in an approximate 600 psi pressure increase, excluding the pressure rise due to unexpanded gas migration. Additionally, as per equations (17) and (21), shorter wells with lower annular volumes V, will experience even higher-pressure increases.

Strip in hole ensuring flow in equals flow out, keeping continuous circulation with the booster or back pressure pump pump.

During the RIH operation, keeping the booster or back pressure pump running and the MPD chokes online allows the MPD system to monitor and ensure flow in equals flow out during static periods, such as every connection. This practice prevents fluid compression as additional drill pipe is lowered into the well and ensures no additional influx is taken during the trip.

However, maintaining flow in equals flow out also prevents gas expansion as it migrates to the surface, resulting in increased surface back pressure during the trip and a subsequent rise in bottom-hole pressure, similar to the scenario described in sub index 3.1.

Strip in hole maintaining the MAASP at the choke, keeping continuous circulation with the booster or back pressure pump.

Using the same configuration as option 5.2 but maintaining the SBP fixed at the MAASP initially ensures no fluid losses and prevents further influx, leaving little room for surge pressures. Therefore, the RIH operation must be done slowly, or the SBP needs to be reduced while running the pipe. However, as gas migrates to the surface, it expands and displaces mud from the well, resulting in an increased flow out. Consequently, this expansion reduces the hydrostatic pressure and, thus, the bottom-hole pressure.

Since the SBP is already set at the MAASP, there is no additional range to adjust the SBP to control the flow out. Hence, this requires stopping the operation to reduce the surface pressure, such as by bullheading the well or circulating to clean out any gas above the bit.

Stop RIH, keep the bit stationary, and circulate the well to lower the SBP while cleaning the well above the bit

Circulating the well before reaching TD may be a prudent step before bullheading, especially if the SBP is already excessively high before reaching TD and further gas expansion is anticipated during the trip. This approach helps in reducing surface pressures by removing any gas from above the bit. It ensures a safe return to bottom and lower pressures for circulating the well once the bit reaches TD.

However, there are a number of concerns that arise in this case:

The gas position relative to the bit remains uncertain, specifically how much gas remains below the bit and may not be circulated. This uncertainty can be addressed by establishing the expected ECD reading at that depth (e.g., using the PWD tool) for a given SBP and flow rate. Calculating the difference between the planned ECD and the actual ECD helps estimate the volume of gas above the bit. This estimation aids in assessing the amount of gas below the bit and determining the necessary SBP to maintain the ECD at TD above the drilling ECD, thereby preventing further influx into the well. This concept is further detailed in section 5.4.1.

Given that the bit is not yet at the bottom, AFLs are lower than those at TD, requiring a higher SBP to uphold the ECD at TD. Additionally, as gas circulates, additional SBP is needed to control gas expansion and maintain a stable ECD at TD. It's imperative to verify that the SBP needed during circulation remains within the limits of the maximum surface pressure or the FIT/LOT pressure.

ECD at bit depth and SBP for a certain ECD target at TD. During drilling operations, a PWD tool positioned near the bit in the BHA accurately monitors ECD at the well's TD. However, there are scenarios that require tripping out of the hole with the PWD tool online, such as wiper trips during pumping operations or positioning the bit at a specific depth before fluid displacement. In these cases, the PWD's ECD reading may not accurately represent the actual ECD at TD. To maintain the required ECD at TD reliably, it is essential to establish an ECD roadmap using a validated hydraulic simulation calibrated during drilling. This method ensures that while tripping out, the driller has predefined PWD readings corresponding to specific bit depths to uphold the ECD within the desired target range.

Below, Fig. 12 depicts the simulation outcomes for Case A detailed in Table 2, maintaining the target ECD of 15.8 ppg at TD. The left plot illustrates the necessary SBP at various bit depths for different flow rates to maintain the target ECD at TD. On the right, the plot displays the ECD readings at the bit for several depths to achieve the desired ECD at TD.

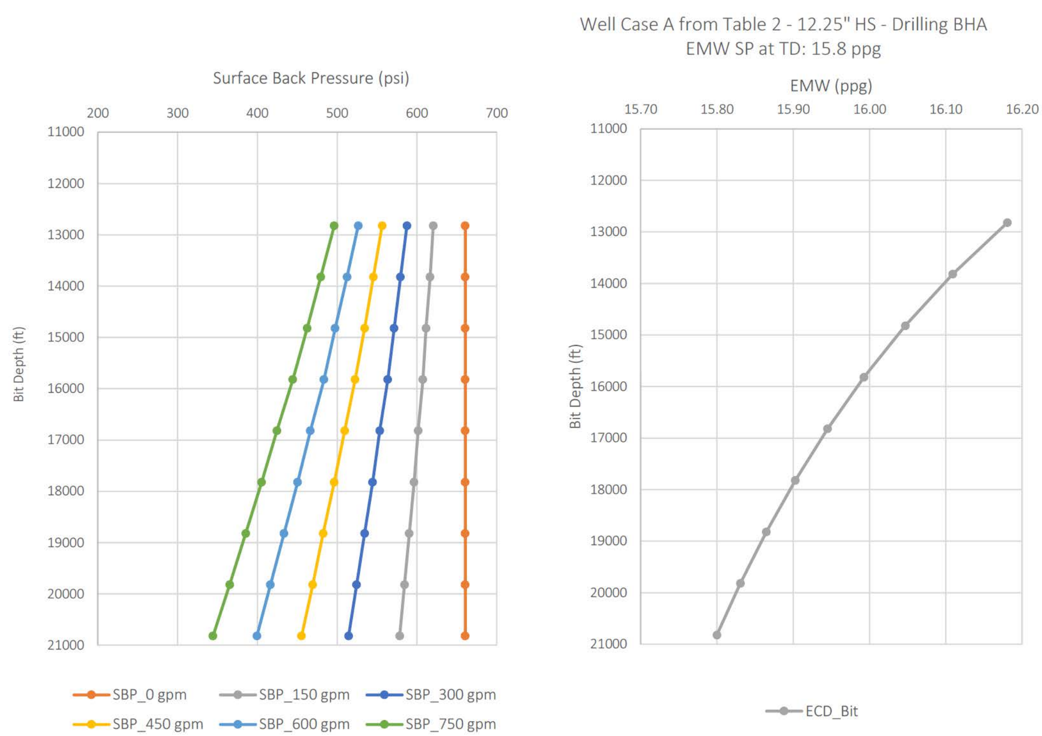

Figure 12—Required SBP along the bit depth to maintain 15.8 ppg at TD, for several pump flow rates for Case A well (left); ECD at Bit Depth (PWD reading) required to maintain target ECD of 15.8 ppg at TD for Case A well (right). When the bit is at TD, the ECD is 15.8 ppg as anticipated. However, as the bit moves upward, the ECD at the bit must increase to maintain the target ECD at TD.

Having this information in advance during a non-drilling influx event allows for several insights. Firstly, it enables determination of the position of the influx relative to the bit. For instance, confirming a surface gain and achieving the expected ECD reading at the PWD with the anticipated SBP indicates the influx is situated below the bit depth. Conversely, if the influx is entirely or partly above the bit, a higher SBP is needed to maintain the ECD at the bit to compensate for hydrostatic pressure loss.

The difference between the required SBP and the pre-calculated (or actual pre-influx) SBP from the roadmap to achieve the ECD at the bit indicates the amount of influx above the bit. This information, combined with knowledge of the total influx volume, allows estimation of the volume below the bit requiring additional back pressure to counteract hydrostatic pressure loss. Utilizing this data, along with the pressure analysis from Fig. 9 (calculated with the bit at TD), determines whether the influx can be safely circulated out within established limits. An example is developed below to understand the use of this charts.

Example: During a trip in the Case A well from Table 2, with the bit at 17,000 feet, the PVT system detects a 15 bbl gain after a connection. The required SBP to maintain the previous ECD at the bit is 50 psi higher than the previous SBP (initial SBP shown as a green diamond in Fig. 13). This increase indicates that part of the influx is above the bit. Fig. 13 shows that a 15 bbl swabbed kick above the bit corresponds to a 90 psi SBP to maintain the same ECD. The observed 50 psi SBP corresponds to 9 bbl, meaning the remaining 6 bbl are below the bit in the open hole, resulting in a lower height and causing less hydrostatic pressure loss.

Compensating the well with 90 psi SBP for the 15 bbl influx will provide an additional safety margin for the BHP at TD. It is essential to understand that the additional 40 psi will generate a higher ECD at the bit, establishing a new reference for circulating the kick out and maintaining a constant ECD during the process.

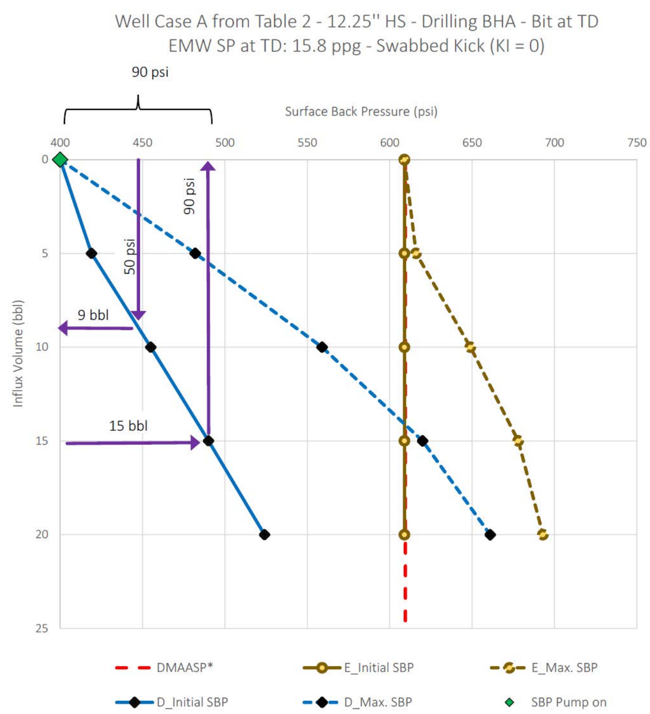

Figure 13—Extension of Fig. 9, surface back pressure for various influx volumes is illustrated in this plot, comparing the initial and maximum SBP during kick circulation for Case D (using the minimum required SBP) and Case E (using the DMAASP* for kick arrest).

Conclusions

Kick Identification

When the bit is on bottom and drilling ahead, the entire drilling system approaches a steady-state condition. Parameters such as SPP, ECD, PVT, and Flow Out, along with derived calculations like EQV, remain stable. This stability facilitates identifying a kick when the ECD falls below the pore pressure. However, during off-bottom operations such as pumping out of hole (POOH) or reaming, the system is under permanent change and becomes unstable, where various factors come into play.

When removing pipe from the wellbore, the SPP reference for the flow rate changes due to the shorter drillstring. The same occurs when changing the flow rate during the POOH operation. As mentioned in 1.1 and shown in Fig. 1, this affects pump efficiency, increasing the pump output and impacting the EQV trend as SPP changes. It is essential to fingerprint these changes to understand their impact on EQV measurements while drilling and tripping, to avoid false kick alarms. Further development is needed to establish a relationship between rig pump efficiency (resulting in the actual volume output) and SPP, along with other variables such as strokes-per-minute (SPM). This will enhance MPD EQV measurements when flow in is a derived variable.

Lastly, we recommend fingerprinting PVT changes resulting from flow rate adjustments, as detailed in section 1.2 and Fig. 2. By analytically deriving the reference volume change from the fluid system's compressibility (as detailed by equations (5) and (6)), we can determine if the PVT change originates from the drillstring fluid volume change. Additionally, variations due to the fluid's thermal expansion under surface temperature changes cannot be neglected. As demonstrated in section 1.3, these variations can account for up to 4 bbl for every 10°F change in a regular PVT system (~1500 bbl total volume).

Kick Arresting

When an influx is detected while drilling, it is essential to increase the ECD above the pore pressure as quickly as possible. The strategy of matching flow out with flow in has proven effective for this task. However, as detailed in section 3.1, during off-bottom operations, there is a high chance the kick is detected when it is already in the gas expansion phase as it travels to the surface and comes out of solution. Therefore, aiming to equalize flow out and flow in might be overly conservative, leading to high SBP, which could require a handover to the conventional well control system and result in increased BHP at both TD and the shoe.

Based on our analysis, we recommend first establishing the last stable ECD at TD, using Fig. 9 as a reference for the required SBP based on the kick size. The initial SBP reference may change depending on the bit depth and circulation status (e.g., pump on or off), which shifts the curve origin on the SBP axis. Once adjusted, the plot provides the reference SBP to compensate for the hydrostatic loss induced by the kick (Case D results).

Next, perform a dynamic flow check (e.g., keeping circulation with the booster or back pressure pump while the MPD chokes are active). If flow out continues to increase, shut in the well. If pressure rises, apply the riser gas handling procedure, as gas is likely in the riser. If pressure remains within MPD limits, run in the hole with the well closed against the MPD choke, stripping on the RCD, and bleed the buildup pressure due to pipe volume displacement. If the flow check is static, RIH with the same SBP and monitor flow out. If circulation is required due to high SBP, follow recommendations from section 5.4.1 to assess the ECD at TD and influx position.

MPD Pressure Limits (MAASP & DMAASP)

Based on the results from section 2, using the pressure limits calculated at TD conditions while tripping out of the hole leads to a conservative approach, limiting the MPD operating range below the actual available capacity. Special consideration is required when running a liner, as limits can change significantly and counterintuitively. For instance, the SBP limit with the liner positioned at the shoe was lower than when the liner was positioned at TD, and using the TD values could lead to exceeding the established weak point pressure limits.

Therefore, it is essential to keep the updated values readily available to ensure the full capacity of the MPD system is utilized while respecting the pressure limits.

Kick Circulation

The pressure required to circulate a swabbed kick with KI = 0 is significantly lower than those obtained during the IME development. This is because IME calculations account for the hydrostatic pressure loss due to the influx volume plus a kick intensity (difference between the Pore Pressure and ECD).

For the study well, two responses were simulated in the event of an influx. It was found that the influx volume can be doubled achieving the same maximum pressure when reacting with the minimum pressure necessary to maintain the reference ECD, compared to the conservative approach of applying the DMAASP*. However, when circulating a kick with less pressure, the liquid and gas expansion is greater. Therefore, a verification must be performed in advance to ensure that it will not exceed the MGS limits.

For cases where the bit is off bottom, the pressure analysis plot from Fig. 9, calculated with the bit at TD, remains valid and provides an additional safety margin since the influx height without the pipe is lower, resulting in a smaller reduction in hydrostatic pressure (though special cases need to be analyzed, such as capacity between an under-reamer hole versus previous casing). This approach is simplistic but aims to be conservative. However, there is still a margin between these values and the drilling limits. Therefore, the driller can adopt an intermediate approach if required.

Nomenclature

AFL = Annular Friction Losses
BHA = Bottom-Hole Assembly
BHP = Bottom-Hole Pressure
CL = Cuttings Load
DMAASP = Dynamic Maximum Allowable Annular Surface Pressure
DMAASP* = Dynamic Maximum Allowable Annular Surface Pressure with ability to shut-in.
ECD = Equivalent Circulating Density
EMW = Equivalent Mud Weight
EQV = MPD volume totalizer, Equivalent volume
HS = Hole Section
IME = Influx Management Envelope
KI = Kick Intensity
MAASP = Maximum Allowable Annular Surface Pressure
MPD = Managed Pressure Drilling
MGS = Mud-Gas Separator
MWD = Measuring While Drilling
NRV = Non-return valve
PVT = Pit Volume Totalizer
POOH = Pumping Out Of Hole
PWD = Pressure While Drilling
RIH = Run in Hole
SBP = Surface Back Pressure
SPP = Stand-Pipe Pressure
SSBOP = Subsea Blowout Preventer
TD = Total Depth
UR = Under-Reamed

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Appendix A

Ideal Gas Isothermal Bulk Modulus

Using the ideal gas equation (A 1), we differentiate the equation to get equation (A 2). Rearranging (A 2) we get (A 3). And lastly, by replacing (A 3) in the bulk modulus definition we get (A 4).

$$P \quad V = nRT \tag{A 1}$$

$$\Delta P V + P \Delta V = 0 \tag{A 2}$$

$$\frac{\Delta V}{V} = -\frac{\Delta P}{P} \tag{A 3}$$

$$\beta_{isothermal} = -V\frac{\Delta P}{\Delta V} = -\frac{\Delta P}{-\frac{\Delta P}{P}} = P \tag{A 4}$$

Appendix B

For additional precision we consider the Real Gas Equation (B 1), we obtain equation (B 2) for the surface flow out change as gas is circulated, and equation (B 3) for the total surface flowout.

$$\frac{P_1 V_1}{R T_1 z_1} = \frac{P_2 V_2}{R T_2 z_2} \tag{B 1}$$

$$\Delta Q_{gas} = \left(\frac{P_1}{P_2}\frac{T_2}{T_1}\frac{z_2}{z_1} - 1\right)\frac{V_1}{V_{annular}} Q_{pump} \tag{B 2}$$

$$Q_2 = Q_{pump} + \left(\frac{P_1}{P_2}\frac{T_2}{T_1}\frac{z_2}{z_1} - 1\right)\frac{V_1}{V_{annular}} Q_{pump} = \left[\left(\frac{P_1}{P_2}\frac{T_2}{T_1}\frac{z_2}{z_1} - 1\right)\frac{V_1}{V_{annular}} + 1\right] Q_{pump} \tag{B 3}$$

Fig. B1 presents the results derived from equations (B 2) and (B 3), illustrating the variations in liquid flow rate change ΔQ_{gas} and the total liquid flow out Q_2 for different surface back pressures, based on the well properties outlined in Table 3.

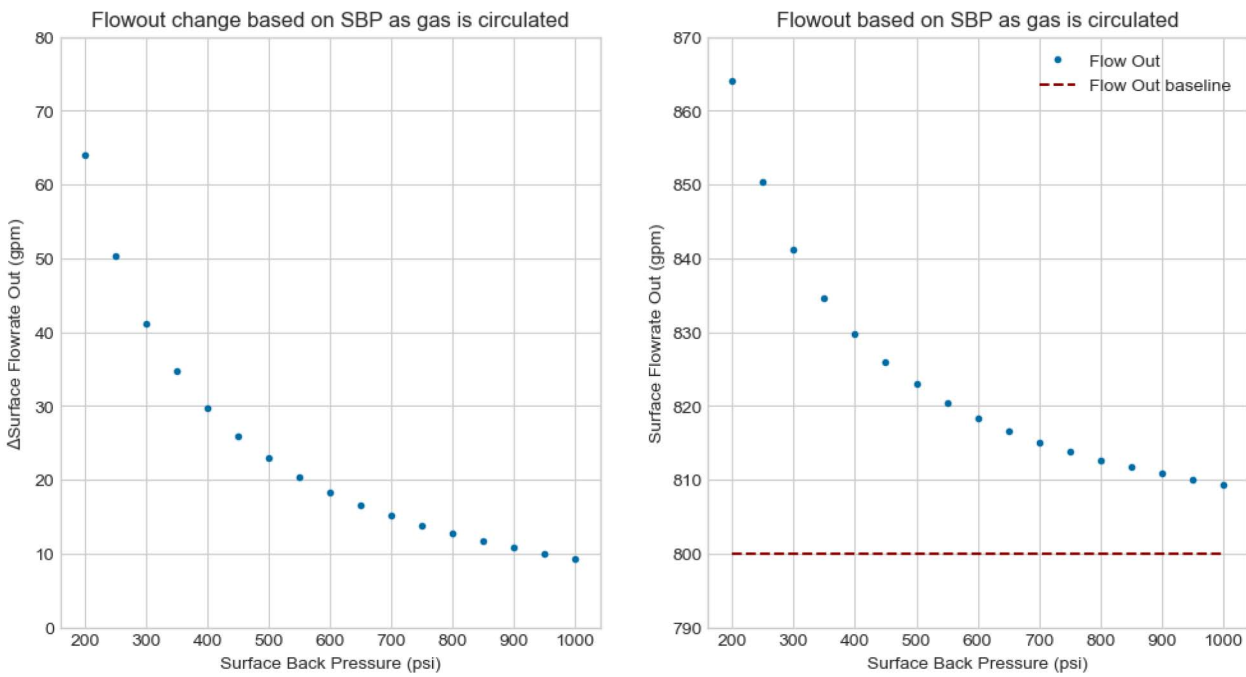

Figure B 1—Change in Surface Flowrate Out due to gas expansion at different surface pressures, derived from the real-gas equation of state (B 1). As surface pressure is reduced, the increase in flow out will be higher, as shown by the lower surface pressure values.

Appendix C

Table C 1—Results from Case A

Bit position	Flow Rate	ECD at TD	ECD at Bit	ECD at Shoe	ESD at TD	ESD at Shoe	Required SBP	MAASP	DMAASP	DMAASP*
		No surface back pressure (SBP 0 psi)								
20825	0	15.19	15.19	15.19	15.19	15.19	661	924	924	924
20825	150	15.26	15.26	15.26	15.19	15.19	585	924	865	848
20825	300	15.32	15.32	15.31	15.19	15.19	520	924	824	783
20825	450	15.38	15.38	15.36	15.19	15.19	455	924	782	718
20825	600	15.43	15.43	15.4	15.19	15.19	401	924	749	664
20825	750	15.48	15.48	15.45	15.19	15.19	347	924	707	609
16000	0	15.19	15.19	15.19	15.19	15.19	661	924	924	924
16000	150	15.24	15.26	15.26	15.19	15.19	606	924	865	865
16000	300	15.28	15.31	15.31	15.19	15.19	563	924	824	824
16000	450	15.32	15.36	15.36	15.19	15.19	520	924	782	782
16000	600	15.36	15.41	15.41	15.19	15.19	476	924	740	740
16000	750	15.39	15.46	15.46	15.19	15.19	444	924	699	699

Table C 2—Results from Case B

Bit position	Flow Rate	ECD at TD	ECD at Bit	ECD at Shoe	ESD at TD	ESD at Shoe	Required SBP	MAASP	DMAASP	DMAASP*
		No surface back pressure (SBP 0 psi)								
20825	0	15.19	15.19	15.19	15.19	15.19	661	840	840	840
20825	150	15.25	15.25	15.26	15.19	15.19	596	840	782	775
20825	300	15.29	15.29	15.31	15.19	15.19	552	840	740	732
20825	450	15.34	15.34	15.36	15.19	15.19	498	840	699	678
20825	600	15.38	15.38	15.4	15.19	15.19	455	840	666	635
20825	750	15.42	15.42	15.45	15.19	15.19	412	840	624	591
16000	0	15.19	15.19	15.19	15.19	15.19	661	840	840	840
16000	150	15.24	15.26	15.26	15.19	15.19	606	840	782	782
16000	300	15.28	15.31	15.31	15.19	15.19	563	840	740	740
16000	450	15.32	15.36	15.36	15.19	15.19	520	840	699	699
16000	600	15.36	15.41	15.41	15.19	15.19	476	840	657	657
16000	750	15.39	15.46	15.46	15.19	15.19	444	840	616	616

Table C 3—Results from Case C

Bit position	Flow Rate	ECD at TD	ECD at Bit	ECD at Shoe	ESD at TD	ESD at Shoe	Required SBP	MAASP	DMAASP	DMAASP*
		No surface back pressure (SBP 0 psi)								
20825	0	15.19	15.19	15.19	15.19	15.19	661	840	840	840
20825	150	15.27	15.27	15.26	15.19	15.19	574	840	782	754
20825	300	15.33	15.33	15.32	15.19	15.19	509	840	732	689
20825	450	15.38	15.38	15.37	15.19	15.19	455	840	691	635
20825	600	15.44	15.44	15.42	15.19	15.19	390	840	649	570
20825	750	15.49	15.49	15.47	15.19	15.19	336	840	607	515
16000	0	15.19	15.19	15.19	15.19	15.19	661	840	840	840
16000	150	15.33	15.19	15.37	15.19	15.19	509	840	691	691
16000	300	15.44	15.19	15.52	15.19	15.19	390	840	566	566
16000	450	15.54	15.19	15.65	15.19	15.19	282	840	458	458
16000	600	15.64	15.19	15.78	15.19	15.19	173	840	349	349
16000	750	15.74	15.19	15.9	15.19	15.19	65	840	250	250