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A simulation-based evaluation of alternative initial responses to gas kicks during managed pressure drilling operations

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A SIMULATION-BASED EVALUATION OF ALTERNATIVE INITIAL RESPONSES TO GAS KICKS DURING MANAGED PRESSURE DRILLING OPERATIONS

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DEDICATION

This work is highly dedicated to Maryam.

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ABSTRACT

Managed pressure drilling (MPD) is an adaptation of conventional drilling that has been developed to manage and control subsurface pressures in the well in order to minimize specific drilling problems. The constant bottom hole pressure approach (CBHP) is a versatile method of MPD, where a closed annulus allows initial responses to kicks other than simply shutting in the well. The objective of this research was to identify and evaluate the best initial response to gas kicks taken during drilling as a basis for developing reliable well control procedures for CBHP operations.

Nine non-circulating and circulating responses (NCRs and CRs) were defined, and their application to kicks in two different wellbore geometries was studied through the use of computer simulations. Two different kick sizes, two different formation permeabilities, and three different kick intensities were considered. NCRs included a rapid shut in (SI) and four different MPD pump shut down schedules ending in SI. CRs included stepwise and rapidly increasing the casing pressure until the mud flow out equaled mud flow in, increasing casing pressure to a pre-defined limit and increasing the ECD by increasing mud pump rates. The initial responses were compared, based on the ability to stop an influx, determine whether the influx was stopped assuming intact wellbore, minimize risk of lost returns, minimize additional kick influx, and minimize excessive pressure at the surface and casing shoe.

The results of over 150 simulations revealed that no single best initial response to all kicks could be identified. Three initial responses showing broad applicability include a rapid increase of casing pressure until flow rates are equal, shutting the well in and an adaptation of the MPD pump shut down schedule that allowed confirmation of a low rate kick. Increasing mud pump rate also showed advantages, but has limited application. Potential advantages and limitations of each were also explained. A method to confirm that the influx stopped during the

application of CRs was also proposed. The best initial response was dependent on well conditions and the equipment used. Therefore, a simple decision tree was developed to plan an appropriate response.

1. INTRODUCTION

1.1 Origins of Managed Pressure Drilling

A decade after the adoption of Underbalanced Drilling (UBD) by the oil and gas industry, conventional drilling remained the more desirable drilling technique for most operations owing to less cost and fewer complications. UBD requires rig personnel training and surface equipment to handle produced fluids. It also poses some limitations on mud pulse telemetry, employed by the majority of Measurement/Logging While Drilling (MWD/LWD) tools. The MWD/LWD tools are often used in the bottom hole assembly (BHA) to simultaneously drill and acquire necessary petrophysical data for real time decision making.

However, the application of conventional overbalanced drilling is often ineffective especially in deep water environments that have a narrow Pore Pressure (PP) and Fracture Pressure (FP) margins (also called the drilling window). Potentially, such environments incur drilling-related problems such as well control incidents, lost returns followed by mud replacement expenses, etc. Another shortcoming of conventional overbalanced drilling leading to a higher cost of operation is a lower rate of penetration (ROP), mainly due to heavier drilling fluid selections.

A recent study[1] has discovered that drilling associated problems account for around one-third of Non-Productive Time (NPT), encountered during drilling of gas wells in the shallow waters of the Gulf of Mexico (GOM). The cost of the NPT associated with these drilling incidents can easily result in costs that exceed a drilling program's Authorization For Expenditure (AFE) and thus leads to many prospects being economically undrillable. This becomes more severe with an increased water depth, where the drilling window becomes more narrow[2].

Drilling in narrow margins not only imposes drilling hazards causing NPT, but also more casing points would be required. A typical constraint of the GOM deep water exploration drilling program is the necessity for about 7-9 seats of casing[3]. This leads to a smaller, ultimate, wellbore size which unfortunately reduces the size of the production string, the production rate that can be achieved, and ultimately, the economics of the well.

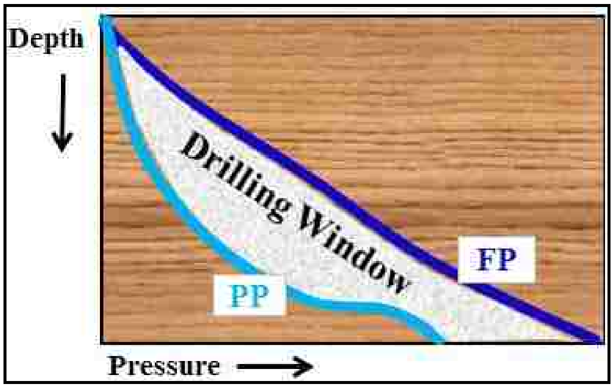
A novel and innovative technique beyond conventional and underbalanced drilling seemed essential to manage annulus pressure within PP-FP margins, and hence, help mitigate drilling related NPTs. Thus, a new technique called Managed Pressure Drilling (MPD) emerged out of the context of UBD technology in 2004[15].

1.2 Conventional Drilling

A pretty wide margin is usually available between PP and FP in conventional overbalanced drilling (Fig. 1.1). Formation PP may be estimated from offset wells and seismic data. Fracture pressure, FP, which is a function of PP and overburden pressure, can be predicted from several available methods during the planning of a well. While drilling, it can be confirmed later by a leak off test (LOT) or a formation integrity test (FIT). This is usually done after drilling a few feet below the newly-cemented casing string[4].

Hydrostatic pressure is present throughout a well when the rig mud pumps are off. This pressure is only a function of mud density and true vertical depth (TVD) at any given point (Eq. 1.1) assuming that the fluid compressibility and temperature effects are negligible[4]. A sufficiently planned drilling fluid density (or mud weight) is theoretically enough to stop any kicks from openhole permeable zones and to keep wellbore pressure at any point within the drilling limits (Fig. 1.2).

$P_{Hyd} = (0.052)\rho D_{TVD}$ .... (Eq. 1.1, field units)



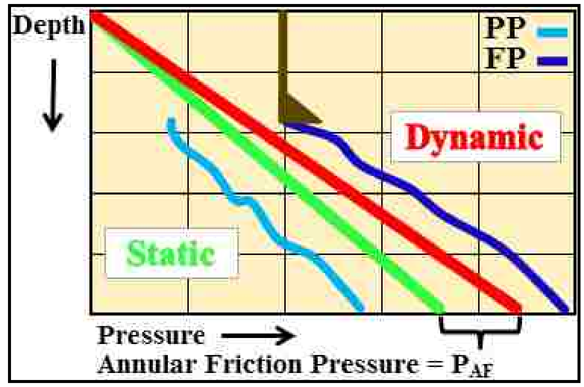


Fig. 1.1: A wide drilling window is typically available in conventional drilling applications

Fig. 1.2: Static and Dynamic pressure profiles in conventional drilling

The Bottom Hole Pressure (BHP or P_{BH}) usually increases when drilling fluid (or mud) is circulated in the well. This is due to an induced pressure on the bottom, caused by the friction created by the upward flowing mud in the annulus between the wellbore and the drillstring. This extra pressure is called annular frictional pressure loss or P_{AF} (Eq. 1.2). Hence, during circulation, a dynamic pressure profile will be established within the drilling window and thus throughout the well (Also Fig. 1.2). Mud then exits at top of the annulus to an "open-to-the-atmosphere[2]" return-flow line. Consequently, the conventional circulation conduit is often referred to as an open system.

$PP < P_{BH} = P_{Hyd} + P_{AF} < FP$ …………………….. (Eq. 1.2, always true at any point in a well)

P_{AF} is a function of mud flow rate-in (Q_{in}), absolute roughness (ε), length of pipe (L), pipe and hole diameters (OD/ID), mud density (ρ), mud rheology and cuttings[4] (disregarding fluid compressibility and temperature effects). Therefore, Eq. 1.2 may be restated to show major parameters controlling BHP (Eq. 1.3). Most cannot be manipulated in real time to change the BHP; however, mud flow rate and density pose the exceptions. One of the most influential parameters on P_{AF} is the borehole-drillstring clearance. Small borehole-drillstring clearance can significantly increase the P_{AF}. This is generally true in moderate-to-slim holes, e.g. 12" to 6" diameter, across the BHA. In large holes, however, the clearance is typically large, and therefore, BHP is not usually friction dominated. In friction dominant environments, an increase of mud flow rate can increase the BHP significantly. This may be achieved in real time by increasing the mud pump rate. Mud density manipulation can effectively change the BHP, but mud-up or mud-down is more time-consuming.

$$P_{BH} = [f(\rho, D_{TVD})]_{Hyd} + [f(Q, \varepsilon, L, OD/ID, \rho, Rheology, Cuttings)]_{AFP} \text{ .... (Eq. 1.3)}$$

Petroleum engineers often use pressure gradients, which simply state the pressure at a depth in terms of an equivalent mud density at its equivalent TVD. Therefore, the actual BHP, whether static or circulating, can generally be expressed in terms of Equivalent Static Density (ESD) or Equivalent Circulating Density (ECD) respectively (Eq. 1.4). If there is no circulation, ECD reduces to ESD.

$$ESD(ppge)\left\{ = \frac{(P_{BH})_{Static}}{(0.052)D_{TVD}} \right\} \leq ECD(ppge)\left\{ = \frac{(P_{BH})_{Circulation}}{(0.052)D_{TVD}} \right\} \text{ .... (Eq. 1.4)}$$

A formation fluid influx (kick) will occur if BHP opposite a permeable zone is less than the PP of the zone. If so, then formation fluid will enter into the wellbore and displace an equal volume of the drilling fluid. Consequently, an extra volume of drilling fluid may be observed at the surface (pit gain). If a kick is taken, the influx must generally be stopped and then out-circulated from the well. This special operation is called well control[5]. While removing the kick fluid, pressure in the well may exceed the fracture pressure of a weaker zone. In that case, an underground blowout can develop and seriously complicate the well control operation. Well control incidents can potentially threaten rig personnel, equipment, and cause NPT. Great efforts are being made to predict PP and FP, but abnormally high or low pressure zones represent an inevitable drilling challenge.

A weakness of open systems, such as the circulating system used in conventional drilling, is lack of pressure control in the annulus. Particularly in case of a kick, the rig mud pumps must be turned off in order to visually observe the mud flow out of the well into the return line. This is called a flow check (or static flow check). If that confirms a kick, the well is immediately shut-in by closing the blow out preventers (BOP); then the pressure in the annulus can be monitored. During flow checks, the reduced ECD unfortunately allows more influx into the well. This requires extra kick circulation work and ultimately causes longer NPT[6, 7, 8].

Another drawback of conventional circulation systems is what petroleum engineers call "wellbore ballooning." Ballooning is a transient condition, caused by wellbore pressure fluctuations. The symptoms are that mud is lost while circulating during drilling, but the well flows mud back during connections when the mud pumps are off. The flow back is a kick symptom, and therefore causes the drilling crew to observe the well (flow check), which consequently increases the NPT. Conversely, it can also mask a well control incident if misdiagnosed[9, 10]. Using a closed and pressurizable system, common in UBD and many MPD applications, can mitigate these problems by allowing a more precise control of the annular pressure.

1.3 Underbalanced Drilling

UBD technology, historically preceding the MPD, intends to control the BHP. However, BHP is kept intentionally below the exposed formation PP at all times to allow pore fluid to enter into the well and be produced at the surface (Eq. 1.5). If the ECD of the lightest available mud is greater than formation PP gradients, then gas, foam, or mist usually is injected into the well to reduce the BHP[11, 12].

$$P_{BH} < PP \qquad \text{(Eq. 1.5)}$$

The primary objective of UBD is to protect the reservoir productivity against damage caused by mud and cuttings invasion into the productive zones. Therefore, it can be the best technique when it comes to low pressure, mature as well as naturally-fractured reservoirs.

However due to technical or economical barriers, the application of UBD is not generally recommended, should well stability be an issue, well productivity is high, or there is a possible occurrence of high levels of sour gas[11, 12].

There are several major benefits associated with the application of UBD technology such as a) potential elimination of formation damage, b) formation characterization while drilling or "testing-while-drilling," and c) identification of production zones that otherwise could not be seen by overbalanced drilling[11, 12]. Although the main focus of UBD is regarded as reservoir-related[2], UBD can also reduce drilling-related problems such as lost returns, slow ROP, or differential sticking.

1.4 Managed Pressure Drilling

A recent study by James K. Dodson[1] Company has revealed that drilling related problems account for approximately 36% of the total reported NPT for gas wells drilled in shallow waters (less than 600 ft) of the GOM prior to 2003. Major drilling related problems that contribute substantially to the above figure are differentially stuck pipe, lost circulation, wellbore instability and kicks[6, 7].

The primary objective of MPD, in contrast to other techniques, is to minimize the NPT by reducing the drilling-related problems. The Intentional Association of Drilling Contractors (IADC) defines MPD as: "an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process[13]." A combination of tools and techniques are used to apply MPD concepts. The main variations of

MPD are: Constant Bottomhole Pressure (CBHP), Pressurized Mud Cap Drilling (PMCD), Dual Gradient (DG), and Health, Safety and Environment (HSE).

1.5 CBHP Method of MPD

One of the popular MPD variations[14] and the focus of this study is the CBHP method. In this method, a combination of P_{AF} and surface back pressure help keep the wellbore pressure constant. The relevant wellbore pressure is not necessarily at the location of the drilling bit, and it can be in the openhole at whatever location requires precise pressure management[6, 15].

The strength of CBHP method lies in establishing an ECD profile much closer to the formation PP gradient. The proximity of BHP to PP profile (or small dynamic overbalance) also increases ROP, reduces formation invasion, allows deeper casing setting depth, reduces ballooning, and reduces swab and surge effects[15].

1.5.1 Application of the CBHP Method

To date, The CBHP method has the most possible applications within all MPD variations[16]. The most important one may be the ability of the CBHP method to allow drilling in very narrow PP-FP margins, which can be experienced in deepwater environment by significantly reducing the drilling-related issues.

Drilling slimholes in abnormal pressure environments is application of the CBHP method. Due to typically high friction in the well, the flow rate can be conveniently changed to achieve the desired BHP that is necessary for the trouble zone. Depleted zones become another potential application of the CBHP method, where a depleted PP and its induced reduction on FP provide the drilling window with a step-back pressure profile, as compared to other embedded high pressure zones. Consequently, a loss of returns in the depleted zone may trigger a kick from the high pressure zone. This situation, known as the loss-kick scenario, requires precise BHP control. It can also increase the number of casing seats to reach total depth (TD), resulting in a smaller, ultimate, borehole size and reduced hydrocarbon production potential.

1.6 Well Control Challenges of MPD

Well control incidents are an outcome of the uncertainty in downhole drilling margins. This uncertainty is generally neither reduced nor eliminated if an MPD method is adopted for a drilling operation. The uncertainty always remains. Although MPD methods and variations generally have better control of pressure environments in a well, the elimination of well control incidents cannot be guaranteed. In fact, narrow drilling environments impose the design of smaller kick margins compared to conventional drilling. Consequently, the well may become more vulnerable to well control incidents. These events may be of less severity than typical, especially if the MPD surface equipment enables faster detection of kicks or losses. Nevertheless, MPD operations have well control challenges just as conventional operations do.

1.7 LSU MPD Consortium Research Objectives

A consortium including LSU and several significant industry members interested in MPD operations was initiated in 2006 for a three-year initial research period. The LSU consortium provided technical advice and the financial means for this research. "The overall objective of the consortium is to establish comprehensive and reliable well control procedures for MPD operations equivalent to, or better than those currently used for conventional drilling operations. The specific goals of the proposed research project are to define, develop, document, and then demonstrate effective well control procedures for use in the CBHP method of MPD operations[17]."

1.8 Thesis Objective

The initial response to a kick represents the immediate task a drilling crew should perform in order to stop the formation influx into the wellbore. Whenever a kick is taken in conventional drilling, the immediate response is to shut in the well and then record the pressures on the choke and drill pipe versus time. These pressure records are interpreted and then used as the basis for removing the kick from the well and ultimately killing the well. On a CBHP method of MPD, however, the well is closed by a Rotating Control Device (RCD) and flow out is diverted through a drilling choke. So, there may be more initial responses to stop the formation influx including circulating and non-circulating responses.

The objective of this research is to investigate and evaluate the best alternative initial responses to gas kicks taken while drilling during the CBHP method of MPD. Alternative initial responses to kicks were investigated by using computer simulations incorporating two different wellbore sizes, two different formation permeabilities, two different kick detection limits, and three different formation pore pressures. The results will provide a basis for further research into well control procedures for MPD operations.

1.9 Overview of Thesis

Chapter 1 highlights the most important concepts of the conventional and underbalanced drilling operations and introduces managed pressure drilling (MPD). The constant bottomhole pressure method CBHP, as a variation of MPD, is also introduced into the focus of this study. The objective of this research is summarized in this chapter. Chapter 2 summarizes the background knowledge about MPD techniques, and in particular the CBHP method, with emphasis on well control operations.

Chapter 3 describes a detailed work plan for conducting the research. It lists different criteria that are included in the simulation study in order to check the effectiveness of the different initial responses to kicks. It also introduces a transient, multi-phase simulator that is used for this study and summarizes the detailed validation work that was done to assure the credibility of the planned work. Chapter 4 discusses two different well representations used for the study, the slim hole, Well X, and large hole, Well Z.

Chapter 5 introduces and describes different initial responses that can stop the gas kicks while drilling during MPD operations. It also explains the application of each on the simulator. Chapter 6 discusses and analyzes the results observed from the simulation study. The effectiveness of responses is compared with the defined criteria. The best initial responses specific to different conditions are categorized. Chapter 7 summarizes the most important conclusions of this research and includes a list of recommendations for future work.

2. LITERATURE REVIEW

A meticulous search was performed through the Society of Petroleum Engineers (SPE) and other resources to take advantage of prior developed knowledge in the context of well control procedures for the CBHP method of MPD. Since CBHP is a variant of MPD, which itself is a descendant of UBD, a broader search was necessary. Consequently many papers, including several presentations, were found up to April 2009, and the relevant literature with an emphasis over well control during MPD operations was organized and will be discussed in this chapter.

2.1 MPD General Concepts

As a new technology, a basic understanding of the MPD concept was necessary before any specific well control research could be realized. Authors, Hannegan[2, 16, 18, 19, 20, 31], Malloy[6, 7, 8], Finley[11, 12], Nauduri[15], Villatoro[21], Grayson[22, 23], Ramalho[24], Kozicz[25, 26, 27], Stone[28], Nas[29] and Cantu[30] introduced MPD and discussed its potential benefits and applicability versus conventional and underbalanced drilling, its variations and special equipment used, and typical offshore requirements, etc. A summary of these discussions follows.

2.1.1 Introduction to MPD

A narrow window between formation PP and FP usually exists in deep water environments (Fig. 2.1). This is generally due to the lesser geostatic weight of the water column, which reduces the overburden as compared to the onshore strata; consequently the drilling window is narrow, i.e., smaller than what is usually seen on land. Typically, there are uncertainties over a formation's real PP and FP before any drilling operation. In conventional drilling, there are also larger uncertainties over the BHP relative to the formation's PP and FP. If wellbore pressure is too close to the formation PP, well control incidents can develop. Conversely, high BHP contributes to stuck pipe and lost returns[2]. Consequently, the economic burden associated with remedial actions could surpass the planned drilling budget or force compromising the TD. This simply implies that conventional drilling in those environments may potentially result in wells being "economically un-drillable[6, 7, 8]." This becomes extremely critical, in the knowledge that at least half of all offshore potential prospects have narrow drilling margins[2].

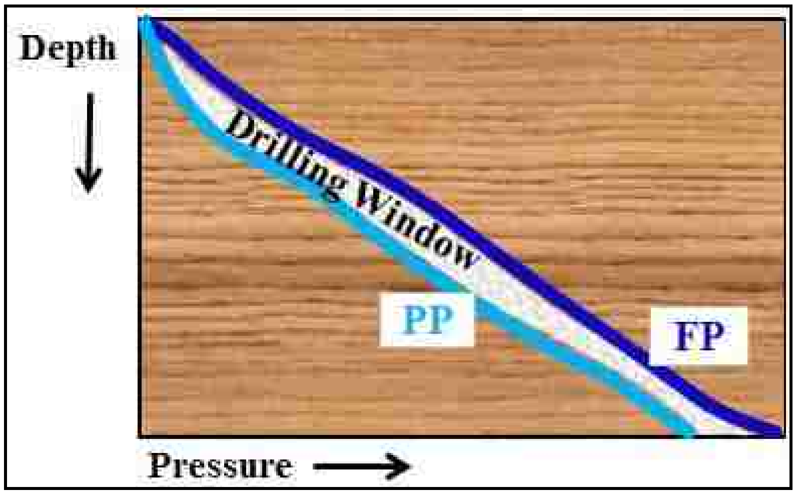


Fig. 2.1: A typical narrow drilling window depiction in marine environments

An accurate annulus pressure management technique is required to keep BHP within narrow downhole pressure limits; otherwise, potentially all of the drilling related issues are prone to occur. Hence a strong drive for a newly innovative and pressure-conscious technology to drill in "trouble zones[2]" safely, coupled with economic efficiency, is deemed necessary. The CBHP method of MPD is intended to fulfill this requirement[6, 7, 8, 20].

2.1.2 Advantages and Limitations of MPD

There are several major benefits in employing MPD, compared with conventional drilling, including: a) improving ROP, b) minimizing differentially stuck pipe, c) minimizing lost returns and associated mud costs, d) reducing well control incidents, e) reduction of redundant casing seats so casing can be set deeper and f) reduction of wellbore instability by less pressure cyclic changes. There is no actual intention of allowing formation influx, therefore less surface equipment is required and associated costs are lower compared to UBD. MPD provides much safer operations in H_2S and HPHT (high pressure, high temperature) environments than UBD[11, 12, 16].

The application of MPD may not be possible if the drilling window is extremely narrow or if the drilling margin varies significantly within the openhole interval[11, 12]. Nevertheless, the application of MPD shows an increasing growth. In Asia Pacific[29], over 100 wells have been successfully drilled using MPD methods.

2.1.3 MPD Equipment

MPD uses a combination of special tools and techniques to precisely control the ECD within narrow drilling margins. This may be achieved by designing hydraulics, and controlling surface back pressure, etc[13]. Minimum equipment required for the MPD practice[6, 7, 8, 16, 19, and 20] includes a rotating control device (RCD), a drilling choke manifold (DCM), and at least one non-return valve (NRV). These tools are briefly explained below.

- **Rotating Control Device (RCD):** The majority of MPD techniques use a closed and pressurized annulus by application of a RCD (Fig. 2.2). A surface or subsea RCD[30, 31] is used as the major safety and well control equipment that is deployed with the BOP to divert the returning mud to a drilling choke manifold. A RCD has rubber elements that permit the rotation and movement of drill pipe while the well is closed. The RCD is a supplement to the BOP stack and is not designed to replace it as a main well control device[6]. Typically, API specification (16RCD) requires a RCD to contain 2500 psi while circulating and stripping, and 5000 while static[98].

- **Drilling Choke Manifold (DCM): A** DCM is a modular choke system (Fig. 2.3) with redundant legs that can be used to control the BHP by manipulation of the mud return flow to create back pressure. Its control can be manual, semi-automatic, or automatic. A DCM is not designed to replace the complete functionality of the rig's choke manifold[6]. In this thesis and for simplicity, a choke implies a drilling choke unless otherwise specified.

- **Non-return valve (NRV):** An NRV or float valve (Fig. 2.4) is used in many MPD operations. It is installed in the BHA and allows only a downward flow of the mud. It provides safety against any possible fluid up-flow migration in the BHA to the surface. Unfortunately, it does not allow any BHP observation in a well control incident, due to the hydraulic isolation of bottomhole and surface. The plunger and flapper types are most common.

There are other optional tools that can be used, together with the basic ones mentioned above to help improve the wellbore pressure management[6]: Continuous Circulating System (CCS), downhole deployment valve, ECD reduction tool, back pressure pump, flow out metering, surface multi phase separators, pressure while drilling tool (PWDT), and hydraulic flow modeling.

A more accurate way of knowing the mud flow rate-out of the well is offered by using a Coriolis flow meter (Fig. 2.5). In conventional drilling, a paddle-type flow sensor provides a very basic method to inquire about the mud level in the return line[4]. If a Coriolis flow meter is used, however, the density as well as mass flow rate can be obtained very accurately. By dividing the mass flow rate by the density, the mud flow rate-out (volume rate) of the well can be deduced[32]. An accurate mud flow rate metering increases kick detection capabilities and identifies the drilling problems more efficiently.

Coriolis flow meters are highly accurate for single-phase fluid. Unfortunately, this error level of the conventional meters would increase over ±20% with a two-phase fluid[32]. Digital Coriolis technology provides more accurate and faster responses for two-phase fluids. A recent Coriolis meter data sheet represented ±0.1% accuracy of volume and mass flow rates and ±0.0005 gr/cc accuracy of fluid density[33].

Fig. 2.2: RCD above the BOP
(With the permission of AT BALANCE™)

Fig. 2.3: A typical automated DCM
(With the permission of AT BALANCE™)

Fig. 2.4: Non-return valve (float valve)
(Plunger, left and Flapper, right)

Fig. 2.5: Coriolis flow meter
(With the permission of AT BALANCE™)

2.1.4 Categories and Variations of MPD

The MPD is divided into Reactive and Proactive categories[13]:

- **Reactive MPD:** In this MPD approach, all the well planning is based on conventional drilling methods. MPD techniques and equipment are used only as a contingency plan to diminish any possible drilling problems or surprises. Typically, a minimum of MPD equipment is required[6, 20].

- **Proactive MPD:** If the drilling plan is built on MPD techniques to take full advantage of their benefits in order to accurately manage the pressure profile in a well, then the approach is proactive. This approach tends to incorporate addition of engineered tools to drill the difficult zones economically efficient with fewer interruptions. Several proactive techniques accordingly, have been developed to allow precise control of the pressure in the annulus. The most common MPD methods or variations are[13]:

  - Constant Bottomhole Pressure (CBHP)
  - Pressurized Mud Cap Drilling (PMCD)
  - Dual Gradient (DG)
  - Health, Safety and Environment (HSE)

There are other methods that are less common or still under development. These include[6]: riserless drilling, casing while drilling, continuous circulation, and ECD reduction.

2.1.5 Design Considerations of MPD Operations

Demirdal[34, 35], Gravdal[36], Petersen[37], Bjorkevoll[38], Iversen[39], Godhavn[40] and Bansal[41] have added to MPD technology by modeling, predicting BHP, and improving wellbore pressure management. However, none of the above mentioned references discussed initial responses to kicks during MPD operations.

Tian[42], on the other hand, investigated whether pressure fluctuations upon breaking circulation can be detrimental in narrow drilling environments, because most drilling fluids are non-Newtonian and have a non-zero yield point. Nygaard[43] and Rasmussen[44] also showed that continuous circulation could reduce BHP fluctuations during swab and surge. These results imply that keeping mud circulation in the well could minimize BHP fluctuations, rather than shut down the mud pumps. This is significant for the alternative initial responses to kicks.

2.2 CBHP Method of MPD

Malloy[6, 7, 8], Hannegan[2, 16, 19, 20] and Nauduri[15] gave more detailed descriptions of the CBHP method of MPD which is explained in this section. As the focus of this study, relative references are given for special emphasis, and subsequently organized in the following sections.

A closed annulus by the RCD, allows better annular pressure management as a method. A well is often statically underbalanced. This refers to the times when mud pumps are off, with the pressure profile shown by the dashed green line in Fig. 2.6. As explained in section 1.2, while the mud pumps are running, the BHP typically increases due to the P_{AF}, and consequently, the dynamic pressure profile is established, shown by the dashed red line. The mud flow rate can be changed in real time to adjust the P_{AF}, to ultimately achieve the required BHP (per Eq. 1.3), in order for the dynamic pressure profile to be kept within the drilling limits.

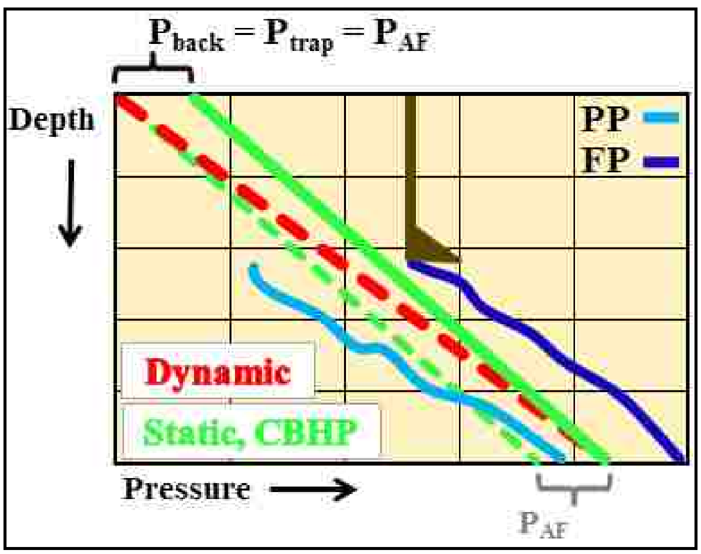


Fig. 2.6: In CBHP method, back pressure must be applied when mud pumps are off

There will be no friction in the annulus when mud pumps are off, and in the case of no action, an influx may occur. To prevent that, in the CBHP method, a pressure equal to the lost P_{AF} is applied at the surface to keep the required BHP constant. This is seen by a solid green line in Fig. 2.6. This pressure compensation practice repeats whenever mud pumping rates are reduced for drill pipe connections or any other reasons.

The surface back pressure is either trapped in the well just before shutting down the mud pumps by adjusting the drilling choke, or a dedicated back pressure pump (Fig. 2.7), diverts the mud flow across the well head. A CHBP method is also possible by application of the Continuous Circulation System (CCS), leaving no requirement to shut down the mud pumps[13]. The control of drilling chokes can be manual, semi-automated, or fully automated; however, the selection depends on how narrow the drilling margin is or how detrimental the connection pressure fluctuations are. In MPD operation, precise control of pressure in the annulus is a primary goal, therefore great importance should be given to any pressure surges.

Overall, CBHP method tries to hold Eq. 2.1 true at all times:

$$PP < P_{Hyd} + P_{AF} + P_{back} = P_{Hyd} + P_{AF} + P_{trap} < FP \qquad \text{(Eq. 2.1)}$$

Fig. 2.7: Back pressure pump (With the permission of AT BALANCE™)

2.2.1 Tripping Operations during CBHP Method of MPD

Tripping operations are identical to that of conventional drilling, if the drilling fluid is heavy enough that the well is statically overbalanced. If the well is statically underbalanced, a heavier mud should be circulated before tripping, or enough volume of pill should be pumped down the BHA to bottomhole to balance the loss of back pressure[6, 45]. In another attempt, "Balanced Mud Pill[46]", a solid free pill was successfully placed on the top of a light density mud column to balance the BHP during tripping operations.

2.2.2 General Considerations for CBHP Method

There are authors who discussed the proper application of the CBHP method, including Spriggs[14], Nauduri[15] and Stone[47]. Although no well control procedures were given, these discussions are important in considering the real potential of the CBHP method.

One of the important issues that should be answered prior to a CBHP job that dictates the depth of planning is "being statically overbalanced or underbalanced[14]". This may have significance if mud is statically underbalanced, and back pressure application is planned during kick incidents. Surface pressure may have limitations and therefore proper planning is required.

Although CBHP variation tends to induce a method that keeps BHP constant, it can be quite ambiguous. Since BHP can be kept constant at one depth, special care must be taken to carefully choose the depth. Incorrect application of the CBHP method could result in cyclic loads being applied to wellbore and thus increasing hole stability problems[15], or in case of a very compressible fluid, not being able to keep the BHP constant during drilling or connections[47].

2.2.3 Pump Shut down Schedule during CBHP Method

A proper understanding of MPD pump shut down, especially its typical duration of application, is required for respective alternative initial responses that apply such a concept. A summary for the relevant references are discussed in this section.

Medley[48] explained a simple and inexpensive manual CBHP method of shutting down the mud pumps and trapping annulus pressure. In his "Step-wise" method, choke pressure is applied while simultaneously reducing the mud pump rate to zero in a step-up and step-down schedule in about eight minutes. This schedule can be created prior to a drilling operation by using any hydraulic model to quantify loss of the ECD at different mud pump speeds. The opposite order is applied before resuming drilling operations. Medley[48] noted a CBHP job in Texas where manual-trapped pressure and fully automated methods experienced no significant difference in connection times. Although the use of an auxiliary pump in an automatic method resulted in minimum BHP variations, the manual method was acceptable as well. He concluded that the trap pressure method can have potential application, although problems may still occur during a fully automated application of the CBHP method.

Arnone[49] investigated the pressure and temperature effects on downhole fluid properties and therefore on BHP fluctuations, showing that the effects were more significant in HPHT environments. He also described a ten minute-long, step-wise, manual pump shut down schedule before connections. He advised that the "theoretical schedule" be correlated with the PWDT reading to develop an accurate schedule, and to practice it before beginning drilling operations. None of the above mentioned literature discussed any initial responses to kicks during the CBHP method of MPD.

2.3 Recent Technologies in CBHP Method

Different technologies have been introduced that primarily allow the application of the CBHP method. Since, these technologies practice different methods to control kick influxes, they are likely to represent different initial responses, and so must be explained separately. Their respective examples in the field also follow each method.

2.3.1 Micro-Flux Control

Santos[50] introduced "micro-flux control or MFC," a new method suitable for drilling in challenging environments. This method is based on a minimum loss/influx of fluids, and involves adjusting the return flow rate in order to manage the bottomhole pressure within the PP-FP window. The well is closed at all times, with the return flow through an automated choke. The system uses a mass flow meter, which is more sensitive and accurate than conventional flow sensors for measuring the return mud flow rate. The return flow is constantly monitored and compared to the actual pump rate and computer-predicted flow to detect a loss or a kick in real-time. In case of any discrepancies, the choke will be adjusted automatically to adjust the return flow to equal the actual flow-in. This is an example of a MPD specific initial response to a kick. This technology claims a kick detection limit of 0.25 bbl of influx, versus 5 bbls or more for conventional drilling. This early detection of a kick or loss can be crucial in regaining the control of a well. Although the intention of this system is to be fully automated, the control can be switched to manual.

The development of the first version of MFC was as an automatic kick detection and control system, which was tested successfully in two phases[51]. In phase one, a drilling simulator was used in conjunction with MFC system, and in phase two, LSU Well #1, with available sensors and a power choke, was used to detect an actual gas kick. The kick was detected very quickly and was circulated out automatically with less than 1 bbl of maximum total gain. This is an example of initial response and control to a kick.

Santos[52] also described another use of MFC with the ultra invasion-drilling fluid (ULIF) technology as a means to significantly reduce drilling problems experienced in deepwater prospects. He claimed application of both methods together can potentially extend the openhole section and eliminate extra casing strings. No well control issues were discussed.

2.3.1.1 MFC Field Examples

Santos[53] described the first two successful applications of the MFC system in Brazil and Texas. Flow rate fingerprinting during pipe connection was practiced before drilling the shoe to help detect any future drilling anomalies. Soon, this practice showed its benefit when kicks were detected due to a different flow out pattern during a pipe connection, and in another case, during back-reaming. An increase in flow out and decrease in mud density were observed after one bottoms-up, which confirmed gas influx. Small increases in static mud weight were managed by monitoring the next pipe connection fingerprints as an initial response to gas kicks during pipe connections. Santos[54] also described application of the MFC in an onshore well in Mexico. The major drive for the employment of the MFC was to minimize the dynamic overbalance to improve the ROP and reduce the possible NPT due to uncertain pressure environments. Trip gas was observed and circulated out with MFC control. No other well control procedures were discussed.

2.3.2 Dynamic Annular Pressure Control

Van Riet[55] announced development and testing of a fully automated prototype that can improve control of BHP during drilling. This prototype, which was later called the Dynamic Annular Pressure Control (DAPC) system, was devised by the Shell research center in 2003. It consists of a hydraulics simulator, and a computer controlled, drilling choke manifold and a back pressure pump to keep BHP constant during drilling operations. The idea behind this method relies on the fact that BHP variations during static and mud circulation can be compensated by the application of back pressure. The computer system receives different operational inputs, or can be calibrated if a PWDT were available to keep the BHP constant by calculating a required set-point for the back pressure pump. The author did not describe how this BHP is defined. However, it appears to be based on the ECD achieved by mud properties, geometry of a well, and pump pressure, etc. He further explained the full scale testing of the system against routine drilling operations in a test well facility in the Netherlands. 'drillers' and 'wait and weight' methods programmed in the computer system were successfully employed to circulate out detected and undetected gas kick tests.

2.3.2.1 DAPC System Field Examples

Reitsma[56, 57] explained the first successful applications of the DAPC system on a HP geothermal job, as well as two offshore jobs in the North Sea and GOM. The DAPC configuration was different for these three cases. In one of them, without a PWDT, BHP was fine tuned by drill pipe pressure data. A manually operated back pressure pump was used which resulted in 50-100 psi BHP fluctuations. BHP was managed, relatively constant, within 30 psi for a fully automated case. Differentially stuck pipe was rectified by the reduction of surface back pressure. Roes[58] also discussed the application of DAPC system for the same well in the GOM. No well control issues were discussed.

Laird[59], Taggart[60], and Geddes[61] described the application of a DAPC-CTD (Coiled Tubing Drilling) project on the same field in the North Sea. No well control issues were discussed.

Chustz[62] explained the application of the DAPC system on the Auger TLP (Tension- Leg Platform) in the GOM to minimize hole instability issues and lost returns, due to pay sand depletions. A lower mud weight was used and back pressure was applied by the DAPC to maintain BHP within the well stability and fracture pressure gradients. This system was fully automated and managed the BHP within 0.3 ppge. No well control issues or loss returns occurred. In an illustrated MPD pipe connection, step-wise pump shut down and start up procedures took around ten and eight minutes respectively.

Chustz[63] gave another update on the same location after drilling four sidetracks. Improvement in the application of the CBHP method, with help from the DAPC system, allowed limiting BHP fluctuations to within 0.2 ppge of the set-point. The accuracy of the mass flow meter, which had been inconsistent, was improved by couple of modifications to 2-3% of the downhole circulation rate. Connection time was also reduced by over 40% to about the same as conventional connection duration. Through 10,000 ft of successfully drilled intervals, 99% of automated pump-shut down and start-up cycles were executed within set-point margins. The planned response in case of a kick was that annular pressure would be increased to a safe level below the minimum pressure that would cause formation fracture, or the pressure rating of surface equipment. This would rapidly increase the BHP and stop the influx, assuming the BHP achieved is greater than formation pressure. This procedure was expected to be viable during drilling at full rate. An alternative response was described as the addition of the same incremental pressure to the pressures in the step-wise MPD pump shut-downs and start-ups schedule. This can potentially stop the influx before shutting in the BOP, and reduces the extra volume of influx taken during pump shut down. Although these well control procedures were addressed, no real experiences executing these procedures were discussed, nor were details about the application of these alternative initial responses quantified.

Fredericks[64] described the application of a DAPC system for a shallow gas well offshore Myanmar. The water depth was 400m, and a gas sand appeared to be 260-400m below seabed. A narrow, drilling margin of around 200 psi increased the possibility that the pressure required to control a gas influx would result in the gas broaching to seabed, which would be very dangerous. Therefore, a faster kick detection, as well as accurate pressure control, were deemed essential to avoid breaking the shoe, should it be necessary to control a gas kick. A flow model predicted that three minutes were required to detect a kick and to shut in the well. This was safely possible if BHP could be kept within a 15 psi window while drilling, and within 45 psi during connections or well control procedures.

Many improvements were needed to achieve this level of accuracy, such as an accurate PWDT, a Coriolis meter and an MWD with wired drill string telemetry to minimize the update time of PWDT data at the surface. Consequently, a kick detection system was developed to detect flow out changes of one gpm. As a result, MPD step-wise pump schedule durations were reduced to less than two minutes. All of these capabilities were tested prior to drilling the shoe by injecting nitrogen in the well to allow it to migrate and expand. A modified volumetric kill method was developed by using the DAPC system and real-time PWDT data, in order to bleed and lubricate the gas flow from the well, so that the BHP could be kept greater than the PP. This detailed planning and preparedness resulted in a successful job. and no well control incidents were experienced

Vogelsberg[65] discussed another application of DAPC system with uncertain pressure environments located onshore Texas. A typical MPD step-wise schedule for pipe connection took 80 and 120 seconds respectively, while the DAPC system kept the BHP constant. Fig. 2.8 shows how the DAPC system responded in ten seconds to a sudden flow rate out drop. Four second transients were also claimed to be detected by this system[66]. No well control procedures were discussed.

Fig. 2.8 is especially important, as the responses of computer simulators to a choke opening adjustment are typically instantaneous. Consequently, a real basis for the duration of return flow monitoring before the next choke adjustments are applied, i.e., a definition of a time step, was required for this research.

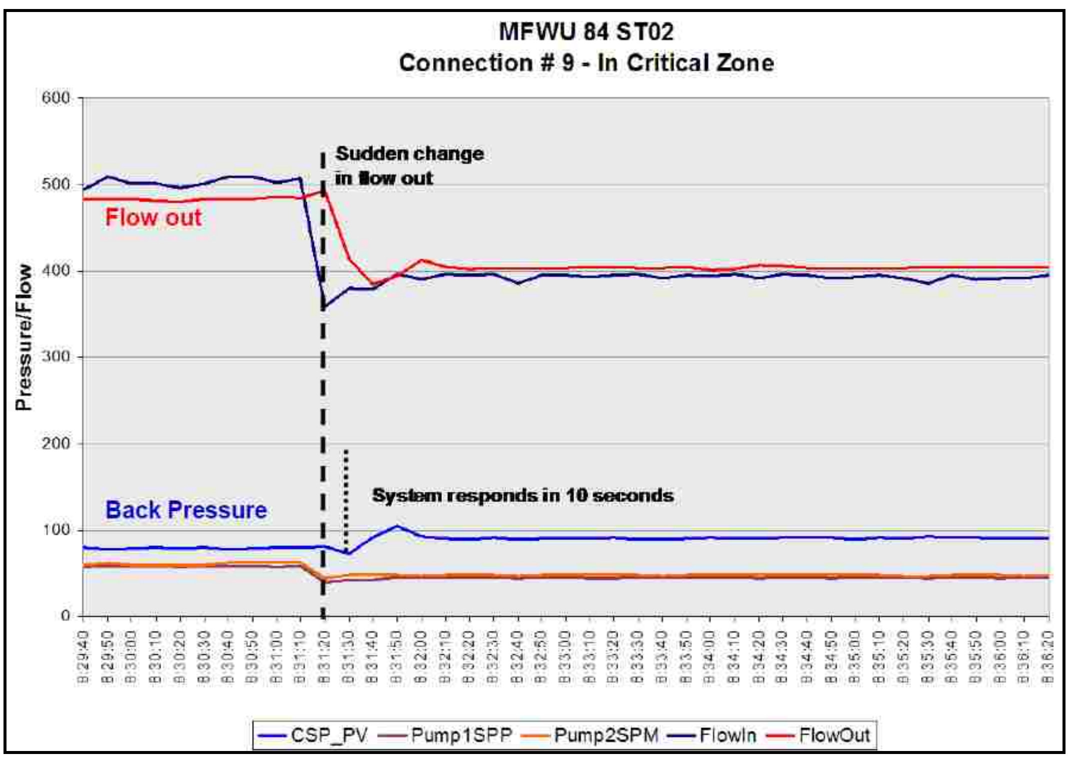


Fig. 2.8: A transient of 10 seconds was detected by the DAPC system (With the permission of SEPCO)

2.3.3 Continuous Circulation System

Jenner[67] introduced CCS, a new way of drilling without shutting down the mud circulation in order to keep the BHP constant. The primary benefits of this system include elimination of BHP fluctuations associated with the conventional drill pipe connections, elimination of circulations before making connections, reduced wellbore "ballooning," and improved hole cleaning. Jenner[67] listed extended reach drilling, deepwater wells, UBD, and MPD as possible applications of the CCS. Calderoni[68] and Vogel[69] discussed the evolution of the CCS from the prototype version to the first commercial tool, which was successfully tested on a land rig in Italy. The application of CCS in a BHA, however, does not improve the ability to detect or control kicks.

2.3.3.1 Continuous Circulation System Field Examples

Calderoni[70] discussed the first field application of the CCS technique in an exploratory well offshore Egypt with extremely narrow pressure margins. Due to the importance of maintaining mud circulation to minimize pressure surges during drilling, dynamic well control procedures were planned for application in case of possible gas influxes. Since increasing the mud flow rate could increase the ECD, and consequently the BHP in the event of any kicks, it was advised as an initial response rather than a shut in response. Should any loss of returns incident occur, reducing the ECD also was advised. Although a series of lost returns and gas influx issues resulted in a 14 day well control operation on one occasion, no further details of the procedures were discussed nor did the author describe any details about the implementation steps of the pre-planned dynamic well control procedures. In terms of the capacity of MPD to minimize drilling problems, it seems, this example was an unsuccessful case.

Calderoni[71] also explained the application of the MFC system and Eni Circulation Device (E-CD), a newly designed continuous circulation valve, in a HPHT environment in the lower

Mediterranean Sea with high kick-loss incidents. Based on the description of the field history and its location, it seems to be in the same location of the previous example. The E-CD is a sub that is made up on top of stand to be picked up by top drive. It also has a manifold that diverts the mud from the standpipe manifold through a hose into the side entry of the E-CD sub. The idea was to reduce BHP fluctuations during drilling by application of E-CD, and simultaneously managing BHP within pressure margins through application of the MFC system.

Several kicks were taken and circulated out conventionally. However, during the 5-7/8" section, MFC was used online only for kick-loss detection purposes. The author demonstrated in detail the benefits of the online MFC application, versus its offline application. The most significant benefit was a total kick volume taken of 24 bbls when the MFC was online, versus 245 bbls when it was offline. The kick volumes reported by the rig crew when MFC was online were 5, 6 and 13 bbls. Since this was first experience by the operator, the automatic kick control ability of the MFC was disabled and SI was used as the initial response.

The significance of this example includes the ability of the operator to TD this exploratory well for the first time after several failures. One of the key factors in this achievement was the early kick detection capability of the MFC system. It can also be deduced that, the application of a dynamic response in terms of only increasing the ECD, as an initial response within such a tight drilling margin, was not successful as evidenced in the theses two examples. Even though the accurate kick detection capability reduced the kick volumes during this example, the significance of a properly planned initial response to ultimately control the well cannot be underestimated from these two examples. Moreover, the kick volumes gained when the MFC was online shows that the kick volumes entering into a well during MPD operations may not always be small, even if kick detection ability is high. This is specifically important for this study, since kick detection limits must be defined for the study of alternative initial responses.

2.4 Examples of Different Initial Responses

Several authors published MPD field experiences that offered different initial responses to kicks, other than what was realized and discussed at the time. We deem it necessary to discuss these separately.

Kadaster[72] explained a coring operation in the Alaskan Arctic where a shallow depth blow-out, believed to be due to probable gas hydrates, had been experienced. A reactive MPD approach was deployed merely to safeguard the operation due to any possible well control incidents. To take advantage of high ECD in the slimhole, a dynamic kill operation using pre-prepared charts was planned. No kicks however, occurred during the operation. In this example, an increased flow rate as an initial response to kicks was planned.

Saponja[73] discussed MPD applications in a region in Canada where well control incidents due to loss of returns or high pressure nuisance gas kicks led to high NPT rising from weighting up the drilling fluid. The reduction of drilling cost was about 20% to 40% during field trials. He advised a continued circulation in the event, a nuisance gas zone influx was encountered, and to reduce well head pressure (WHP) by application of a dynamic annular pressure control technique. Saponja[73] also advised that the “Bleed and Feed” technique be applied as an advanced variation to dynamically control annular pressure for that purpose. This method potentially de-energizes the nuisance kick zone by pressure depletion. This is an example of initial response to nuisance gas kicks. If the influx does not stop, then the operation must switch to a well control operation. Consequently, a Flow Control Matrix (FCM) was defined that will be discussed separately. He also explained that MPD utilizes the conventional and UBD well control procedures. He emphasized that proper risk management is required in order to bridge from MPD operations to well control procedures.

Vieira[74] explained an application of the CBHP method of MPD in an onshore exploratory well that had uncertain pore pressure; tight hole and gas kicks had also been experienced. A flow control matrix was also defined (refer to 2.6). A semi-automated choke was used, and a step-wise pump schedule was implemented for drill pipe connections, but the duration of the schedule was not mentioned. However, plots showed two step-wise schedules that were executed within 15 and 20 minutes. These are examples of a manual MPD pump shut down and start up durations. No MPD well control procedures were addressed; however some elevated levels of connection and trip gas were observed, which was reduced by increasing the ECD.

Perez-Tellez[75] talked about a CBHP method application in a HPHT field in southern Mexico with potential problems such as lost returns, formation influx as well as stuck pipe, and H_2S hazards. A lower dynamic overbalance using the CBHP method was realized to minimize these problems. A MPD pump shut down schedule was also constructed based on equal flow rate reductions, but its duration was not mentioned. Several gas pockets were experienced while drilling execution due to the near-balance nature of the operation. However, the gas pockets were circulated out by operating a semi-automated choke, and without requiring action to shut the well in. This is an example of a circulating initial response by increasing the choke pressure. No details about the specific procedures were given. A FCM, however was designed for the proper transition to SI response (refer to 2.6).

Solvang[76], Syltoy[77], and Bjorkevoll[78] discussed the MPD operations in heavily depleted HPHT Norwegian offshore fields. Use of an advanced dynamic flow and temperature models, together with an automated choke helped to maintain a constant BHP. Additionally, the application of CCS also minimized BHP fluctuations. Choke pressure was calculated by the model to achieve a required ECD. Syltoy[77] mentioned that no influx or connection gas was experienced during the operation, but about 3% drilled gas in the mud was observed to cause pit gain to increase about 400 to 500 liters each time. The corresponding flow rate out increase was up to 300 l/min. These gas events were best identifiable by “fingerprinting”. If necessary, drilling was stopped and gas was circulated out by application of casing pressure, since shutting-in the well was not recommended. This clearly would have interrupted the hydraulics regime in such HPHT environment, causing more BHP fluctuations. The application of choke pressure during mud circulation to control a kick is an important example of initial response. Syltoy[77] also concluded that a good identification of gas events versus influxes eliminated many shut-ins.

Carlsen[80] explained a modified application of dynamic SI, after taking a kick with automatic control of the annulus pump rate and the choke in order to maintain a constant BHP. Although dynamic SI is introduced for the DG method of MPD (Schubert[79]), a modified version for application in typical MPD operations was tried in this paper. For highlighting the benefits, conventional SI was also executed by shutting down the mud pumps, checking for flow, and finally fully closing the choke.

The annulus pump, which can only pressurize the upper part of an annulus, acts like a back pressure pump. For the dynamic SI, a kick is also detected by an increase in return mud flow. In that case, while running the same pump rates, the choke opening is reduced to stop the pit gain increase. The BHP is then measured by the pressure sensor in wired pipes. The new BHP is taken as a new set point for the automated control of annulus pump and choke opening in order to keep the BHP constant during kick control. A new mud weight is made and ‘drillers’ or ‘wait and weight’ methods can be applied for kick circulation. Dynamic SI procedures resulted in much less kick volume. Due to the loss of P_{AF} during a conventional flow check, influx intensifies, and that was the reason for the larger gain for the conventional SI. Since the well is not SI during the application of this method, the pore pressure of the kick zone cannot be quantified. This is an important example of a circulating response to stop a kick by application of choke pressure at running mud pump rates.

2.5 Examples of other MPD Applications

Soto[81], Beltran[82], Miller[83], Shen[84], Foster[85], Dietrich[86], Hernandez[87], Dharma[88] and Niznik[89] discussed successful applications of MPD to minimize drilling related problems in Venezuela, Mexico, China, Canada, Texas, Mexico, Indonesia, and in the Persian Gulf (offshore Qatar), respectively. Hannegan[16, 19, 20] claimed that MPD well control procedures are similar to that of conventional drilling. None of authors discussed any MPD well control procedures.

2.6 Flow Control Matrix

A Flow Control Matrix (FCM) is defined to indicate when the transition to a well control operation is necessary. There are several authors who used or indicated a FCM in their published experiences. Since the matrix associated with the FCM represents well control procedures, it importantly should be explained and discussed in this section.

A version of the FCM or operational matrix[90] is required by the MMS, before a permit to drill can be granted for MPD job. Fig 2.9 shows a sample matrix given for the CBHP method, to be used in the GOM region. The chart provides an easily understandable hazard level, as well as instructions for rig crew to conduct a safe transition to well control operation, depicted by the red color.

The influx indicator seen at the left of the matrix can be any or any combination of influx state (descriptions of flow characteristics), influx rate, influx duration, and influx gain. Consequently, each can be subdivided into none, low, medium (or moderate) and high to fit into the table. These alarm levels must be quantified by relating them to the maximum operational limits. An example of influx gain associates low, moderate, and high gain with 0.5 bbl, less than

1 bbl and greater than 1 bbl respectively. The surface pressure indicator at the top of the table describes different levels of pressure that can be applied to the annulus.

Saponja[73] explained the FCM procedure used. Since nuisance gas kicks were expected, the matrix included the gas rates at the left and the WHP at the top. He discussed that a basis for designing a matrix should be: maximum pressure rating of RCD and choke manifold, maximum capacity of surface separators, and MPD maximum allowable casing pressure (MACP) to construct pressure indication levels. Vieira[74] constructed his FMC based on influx gain and WHP. A 2 m^3 of kick influx necessitated the response to the kick being shut-in. Perez-Tellez[75] used influx state versus WHP to design his FCM. All of these authors employed different initial responses in their FCMs such as: increasing or decreasing back pressure, pump rate, and / or mud density.

MPD Drilling Matrix		Surface Pressure Indicator (See Chart 2 Below)			
		At Planned Drilling Back Pressure	**At Planned Connection Back Pressure**	**> Planned Back Pressure & < Back Pressure Limit**	**≥ Back pressure Limit**
Influx Indicator (See Chart 1 Below)	**No Influx**	Continue Drilling	Continue Drilling	Increase pump rate, mud weight, or both AND reduce surface pressure to planned or contingency levels	Pick up, shut in, evaluate next action
	Operating Limit	Increase back pressure, pump rate, mud weight, or a combination of all	Increase back pressure, pump rate, mud weight, or a combination of all	Increase pump rate, mud weight, or both AND reduce surface pressure to planned or contingency levels	Pick up, shut in, evaluate next action
	< Planned Limit	Cease Drilling. Increase back pressure, pump rate, mud weight or a combination of all	Cease Drilling. Increase back pressure, pump rate, mud weight or a combination of all	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action
	≥ Planned Limit	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action	Pick up, shut in, evaluate next action

Fig. 2.9: A typical CBHP method operational Matrix by MMS GOM region[90]

As it can be seen from the MMS[90] matrix, changing back pressure, mud flow rate and / or mud density or SI are the distinctive initial responses to kicks that are considered appropriate by the MMS, and which appeared on the other samples of FCMs. However, the exact sequence, duration or application of each is not discussed. The most important objective of this thesis is to evaluate these initial responses and any other relevant responses that effectively stop the influx.

2.7 Initial Response Comparison Study

Das[91, 92] was the first researcher who compared initial responses study research to document apt well control procedures for the CBHP method of MPD initiated by the LSU MPD consortium in 2006. Das[91, 92] compared three primary responses, including SI the well conventionally, increasing back pressure while keeping the same mud circulation rate, and ultimately increasing mud circulation rate without changing back pressure, using computer simulations. Each of these responses can potentially stop an influx. However, each mechanism that increases the BHP over the kick zone pressure to stop the influx is different. Therefore, assessment criteria for effectiveness were defined. Those included whether a given response resulted in:

- A conclusive way to stop influx that can be insured or confirmed
- A conclusive way to identify downhole losses or wellbore being intact
- Minimum surface pressure
- Minimum risk of loss of returns

A transient multiphase flow simulator (Ubitts™) was used to predict the application of the initial responses to different kicks. A 6” slim-hole (Well X) and a 17 ½” large-hole (Well Z) were selected as representative geometries, and the related well data, such as PP, FP, productivity index, mud data, and zones of interest were given by the project sponsors. Since these well scenarios were MPD applications with narrow drilling margins, taking a kick could risk lost returns in weaker zones or a loss of return could trigger an influx from a higher pressure zone. For the purpose of generality to responses, the sensitivity study was also performed by changing kick size, kick fluid (oil, gas), kick intensity (underbalance), and drilling fluid type

(Water and oil based mud). An increase of mud flow rate out was used as indication of influx during drilling. Das[91, 92] conclusions included:

- No response was identified as the best, as effectiveness depends on hole size and relative location of kick and loss zones.
- The circulating responses may stop an influx faster than SI and impose less casing pressure; this reduces the risk of lost returns.
- Increasing the mud flow rate requires the least choke pressure to maintain a given BHP and consequently, the least risk of lost returns at the casing shoe or a surface equipment failure; however, this is not a successful response in large holes or in case the mud pump rate is limited.
- Increasing back pressure is simple to apply and reduces the risk of breaking the shoe relative to a SI response. However, it can mask lost returns.
- SI response is fast, simple, and known to the industry; however, it causes the highest casing pressure and increases the chance of fracture at the shoe or exceeding the pressure rating of the surface equipment.

There were a number of limitations to Das's work that opened the stage for this study. One of the most important is that Ubitts™ only accepts Newtonian fluids, but generally, most drilling fluids are non-Newtonian[4]. This can undermine the accuracy of the simulations, and Das[91, 92] recommended that Ubitts™ be updated to a more accurate simulator for future research. He made several AFP hand calculations for a steady state, single WBM fluid to evaluate the Ubitts™ hydraulics predictions, which did not show a good match. Additionally, the time to stop larger kicks was less than the time to stop small kicks. This behavior was opposite the research expectation. Das[91, 92] also recommended the future upgrade to Ubitts™ be evaluated for the accuracy of its predictions.

Das[91, 92] also recommended studying the effects of the productivity index (PI) on the effectiveness of the responses. PI controls the amount of influx feed-in rate into the well, and whether it is high or low can have differing impacts on the ultimate control of an influx.

The other limitations of his work that appeared in the recommendation section of his thesis, relates to a limited number of kick intensities that were studied. Incorporating different formation pressures in order to change the drilling margin can help to define the limitations or boundaries for effective application of a given initial response. Since a best initial response was not identified by Das's work, meeting the initial LSU research consortium objectives required more work, as embodied in this thesis.

2.8 Simulator

Abdul Mujeer[93] discussed how a proper hydraulics flow model could impact the successful application of a CBHP method in offshore India. Consequently, for a valid study of alternative initial responses, and in regard to Das[91, 92] recommendations, Dynaflodrill™ was suggested by the LSU MPD consortium members to be used for this simulation-based study.

Rommetveit[94] introduced Dynaflodrill™ as an advanced simulator with a transient multiphase hydraulics model, useful for proper design of UBD operations. He described laboratory experiments and full scale testing used to evaluate the simulator. The results showed that the simulator predictions of BHP and parasite string gas injections were acceptable for a steady-state flow of gas-liquid mixtures, as well as for transient behavior during pipe connections.

No more references to the further application examples of Dynaflodrill™ could be found, because the names of software are not published in the papers. An evaluation of the validity of Dynaflodrill™ predictions is planned for this research; therefore, the limited number of Dynaflodrill™ application, found in the literature, may not be critical.

3. RESEARCH METHODOLOGY

3.1 Summary of Project

This study will identify and evaluate reliable procedures that may be applied upon well control incidents during the CBHP method of MPD operations. The initial response to a kick aims at stopping the formation influx into the well. There can be different alternative initial responses to stop an influx, but not all promise a successful and efficient well control operation. Therefore several initial responses were identified in this project and will be specifically evaluated for minimizing associated risks and maximizing effectiveness. An apt initial response to a kick is a critically important step to assure safe overture into well control operation.

3.2 Research Plan

Steps taken to conduct this research are detailed in this section:

1. Current knowledge: Available literature about MPD operations with an emphasis on well control areas was reviewed during the course of this research to assure that the study takes prior industry knowledge into account. This review was reinforced by the sponsors' feedback throughout the project.

2. Simulation: The flow of kick fluids into a wellbore is a transient and dynamic event. Therefore, transient computer simulations may be an efficient method to study alternative initial kick responses. Dynaflodrill™ (Version 4) was selected as the advanced, multi-phase, transient simulator. An interactive training session was held to learn the software. More detailed information about Dynaflodrill™ and the validation study that was performed will be covered in the next section.

3. Representative well geometries: In order to simulate kick scenarios, representative geometries must be defined in Dynaflodrill™. This includes casing and drill string data, reservoir and drilling fluid data, etc. During this study, two well descriptions provided by the

sponsors were Well X, a 6" slim hole, and Well Z, a 17 ½" large hole, both of which were used on previous research done by Das[91]. Both wells have drilling environments suitable for MPD application. Well X is a directional well with a potential deep kick zone, whereas Well Z is a straight hole with a potential shallow kick zone. The required well information to set up Dynaflodrill™ input files was based on descriptions of actual wells, but the well names X and Z are used for ease of reference and to maintain anonymity of the operators and well locations. The combination of these well geometries and kick scenarios provide a wide spectrum to help investigate the generalities of successful initial responses. The descriptions of Well X and Z are explained in Chapter 4.

4. Kick scenarios: In order to investigate initial kick responses, it is critical that kick scenarios attempted in simulations be realistic, and resemble the occurrence of typical kick incidents during drilling operations. For this entire study, only kick scenarios that occur upon drilling into a zone where the pore pressure exceeds that which was expected will be discussed. Kicks due to sudden BHP fluctuations or surface equipment failures were discussed separately by Hakan Guner[95]. Cases of lost returns on bottom inducing kicks from a shallow, high pressure zone were studied by Das[91].

The industry sponsors requested an emphasis on initial responses that could successfully stop formation influx and avoid loss of returns. Therefore, simulation of cases where the weak zone is above the high pressure zone, i.e., where actions to control a kick increase the likelihood of lost returns, are the focus of this study. This weak zone is typically the formation at the casing shoe, at the top of the open hole. Consequently, risks induced to a casing shoe are one basis for evaluating an initial kick response.

There are many factors that contribute to the severity of kick incidents, including under balance pressure at the kick zone, the fracture pressure of weak zones, the kick zone's permeability, the kick fluid type and density, the drilling fluid type and density, the kick volume, etc. In reality, most of these parameters are not accurately known before drilling into a kick zone. Additionally, the interaction of kick fluid and drilling fluid can also complicate the well control operation. The LSU consortium members agreed on simulating kick scenarios for the worst case, which is usually associated with gas kicks in water-based mud (WBM). This is due to the fact that gas solubility in WBM is usually minimal and therefore, the gas migrates to surface rapidly, causing potentially excessive surface pressures. The results developed from this approach are conservative, and therefore their application are expected to be safely extended to the less severe cases.

Reducing kick scenarios to conditions mentioned above would still require a very large number of simulations to cover all possible combinations of influencing parameters, which is not practically possible. A reasonable combination of the mentioned parameters includes extreme cases such as easily- versus hardly-controllable kicks which ultimately results in a large reduction in the number of simulations. Moreover, those extreme kick scenarios, plus the fact that Well X and Well Z are, in a sense, extremely different wellbore sizes, broaden the study of initial kick responses. Hopefully, this would generalize the successful initial responses more relevantly. For this purpose, two extreme kick zone permeabilities of 5 mD and 500 mD were selected. Additionally, in order to simulate hardly controllable kicks as well as routine kicks, a range of kick intensity, and therefore kick zone pore pressures, were studied. In order to increase pore pressure systematically, the kick margin at the shoe was used as a basis for selecting pore pressures. The kick margin for MPD operations is defined herein as the difference between the shoe fracture pressure and the ECD in the annulus opposite to the shoe.

Fig. 3.1 illustrates a PP and FP window for Well X, where hydraulics is adequate to keep the well dynamically overbalanced, i.e., dynamic wellbore pressure is greater than formation pressure at all depths. This displays a base case where no kick will occur, even during drilling into the high pressure (HP) zone at about 15000 ft TVD. For kick scenarios however, 20%, 60%, and 120% of the kick margin will be added to nominal (or planned) formation pore pressures to generate three underbalanced cases that have different kick severities. These combinations for Well X and Well Z, at their respective drilling pumping rates, will create about 0.1, 0.5 and 1.2 ppge circulating underbalanced (Circ UB) pressure gradients upon drilling into the HP zone. The base case serves a "no kick" scenario when it comes to compare and contrast initial kick responses to the routine operation.

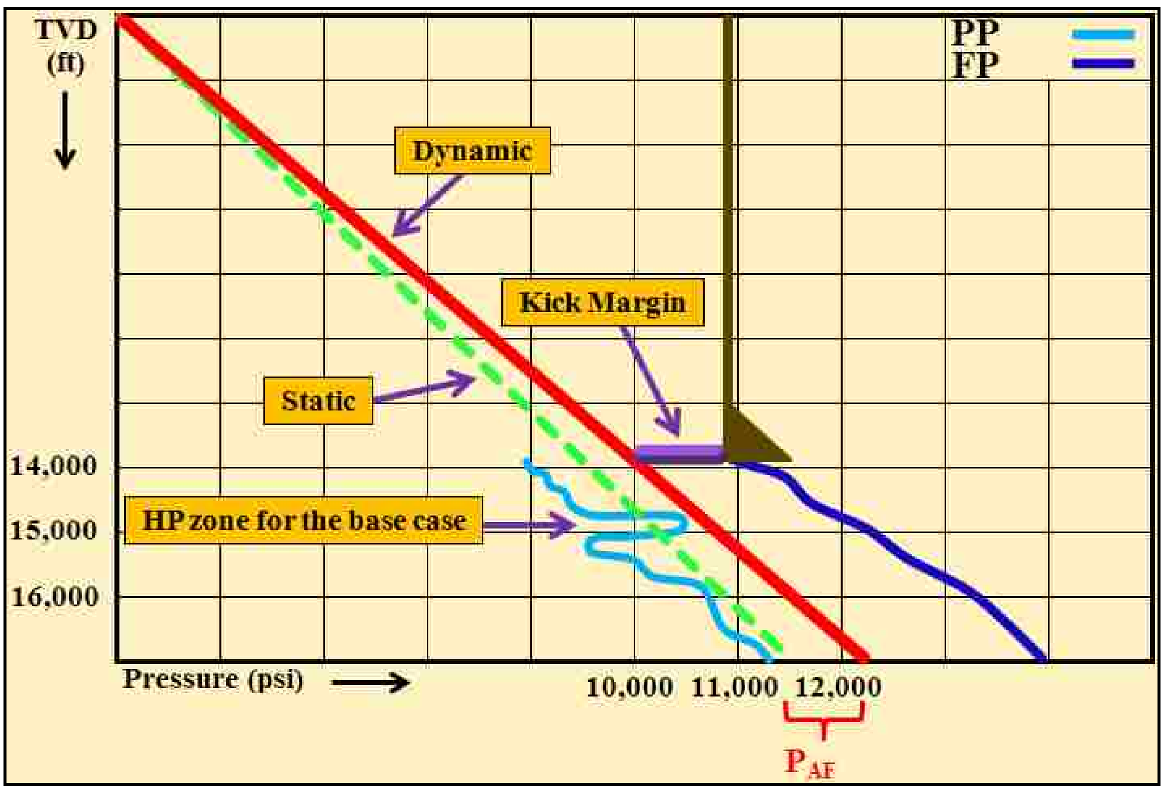


Fig. 3.1: Wellbore pressure versus depth for routine CBHP MPD operations

5. Kick detection criteria: Kick volume in a well is a function of differential pressure at the kick zone, the permeable zone's characteristics, and kick detection capabilities. High kick volumes can potentially risk the well control operation. On the other hand, those initial kick responses that successfully stop small kick volumes may not effectively stop large kicks or may increase the risk of lost returns significantly when applied to a larger kick. Therefore, the study

of alternative initial responses to kicks should be evaluated against its sensitivity to kick volumes.

Originally, the LSU consortium members agreed on an increase in mud flow rate versus time as the primary, field-applicable indication of downhole influx. Consequently, in cases with accurate surface flow out metering, sustained increases of 5% over 1 minute or 3% over 2 minutes were defined as kick indications. Otherwise, a 20% increase over 1 minute or 10% over 2 minutes were defined as kick indications, representing cases with conventional flow out monitoring. Later, when Well X simulations were being reported, the practicality of these kick detection criteria was questioned by some consortium members. Additionally, kicks that were deemed conclusive with accurate flow out metering were only about 1 bbl of gain for all simulated cases of Well X. This did not seem to be a conservative outcome, and consequently, the kick detection criteria were revised.

The new criteria recognize kicks as conclusive upon 2 or 20 bbls of gain for cases with or without accurate flow metering, respectively. These limits which are more routine per literature review (chapter 2), are also easier to implement on simulations. Thus all of Well X simulations were repeated with 2, and then 20 bbls, of gain before further simulation study of alternative initial kick responses.

6. Initial kick responses: Six responses were defined during the course of this research, in addition to the three original initial responses that Das[91] investigated. Therefore, nine initial kick responses were evaluated for this study. The description of each initial response is explained in Chapter 5.

7. Effectiveness criteria: After the application of the initial responses on the kick scenarios, some evaluating criteria must be defined to help select the more favorable responses. In order to assess which alternative kick responses are more effective, the purpose of an initial response

should be considered. An initial response aims to stop an influx. Therefore, those responses able to stop the influx are judged more effective than the others. However, a trade off might become an excessive casing pressure that breaks the shoe and causes loss of returns. For example, if a response allows more kick volume into the well while stopping the kick, the loss of hydrostatic pressure could increase the risk in further well control operations. Consequently, the extra volume of kick into the well after application of an initial response is also critically important. This can be monitored by monitoring the total pit gain. Therefore, several criteria should be met collectively before an initial kick response may be recognized as the best response:

- Ability to stop formation flow
- Ability to verify that formation flow is stopped (assuming intact wellbore, due to inability of DFD to address lost returns scenarios)
- Ability to minimize formation fluid volume (minimize pit gain)
- Ability to minimize pressure imposed on weakest formation (risk of lost returns)
- Ability to minimize pressure imposed on surface equipment (risk of failure)
- Ability to handle fluid rates (risk of exceeding flow capacity of surface equipment)

3.2.1 LSU MPD Road Map

A work flow to show the steps taken to complete the numerous mentioned simulations was developed before commencing the simulation study. This work flow, termed a “road map,” defines the research method. It is in fact a snap shot of the entire research plan. Fig. 3.2 shows the matrix of simulation scenarios in which a well geometry is selected and the respective well data which will be used in DFD. Later, proper formation permeability and pressure will be chosen. The larger formation pore pressures are calculated using kick margin (or MAASP). Fig. 3.3, however, depicts general sequential steps taken to complete the entire research. Together, these figures are the road map for the project

After setting the inputs into DFD for a specific kick scenario (per Fig. 3.2), drilling is started, and pit gain will be used as indicative of a kick. Each initial response is applied, and the results are recorded for analysis. Consequently, after all initial responses are applied to the different kick scenarios, the results are compared and the best response is identified as per the effectiveness criteria.

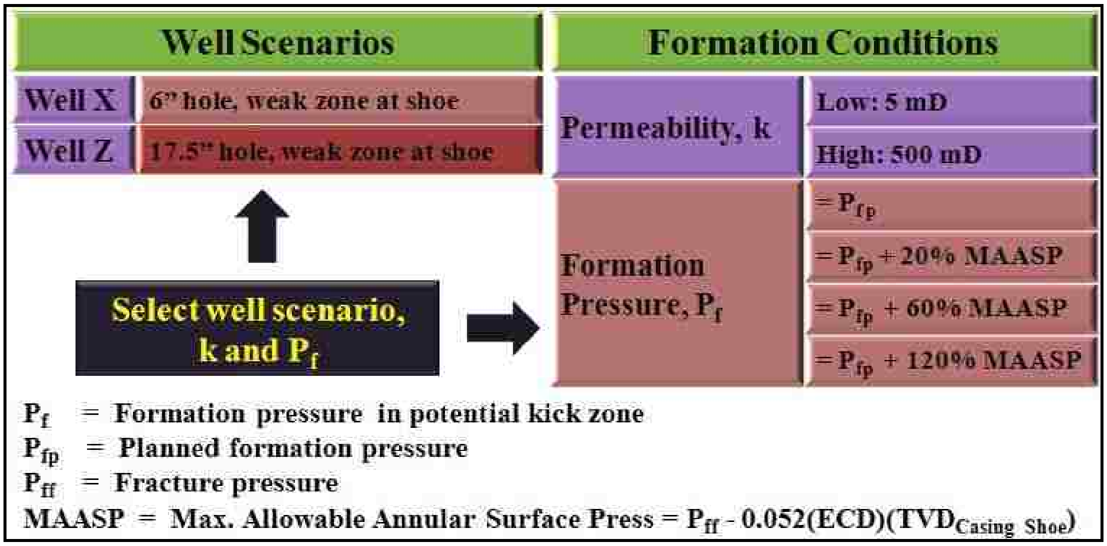


Fig. 3.2: Matrix of simulation scenarios and sensitivities

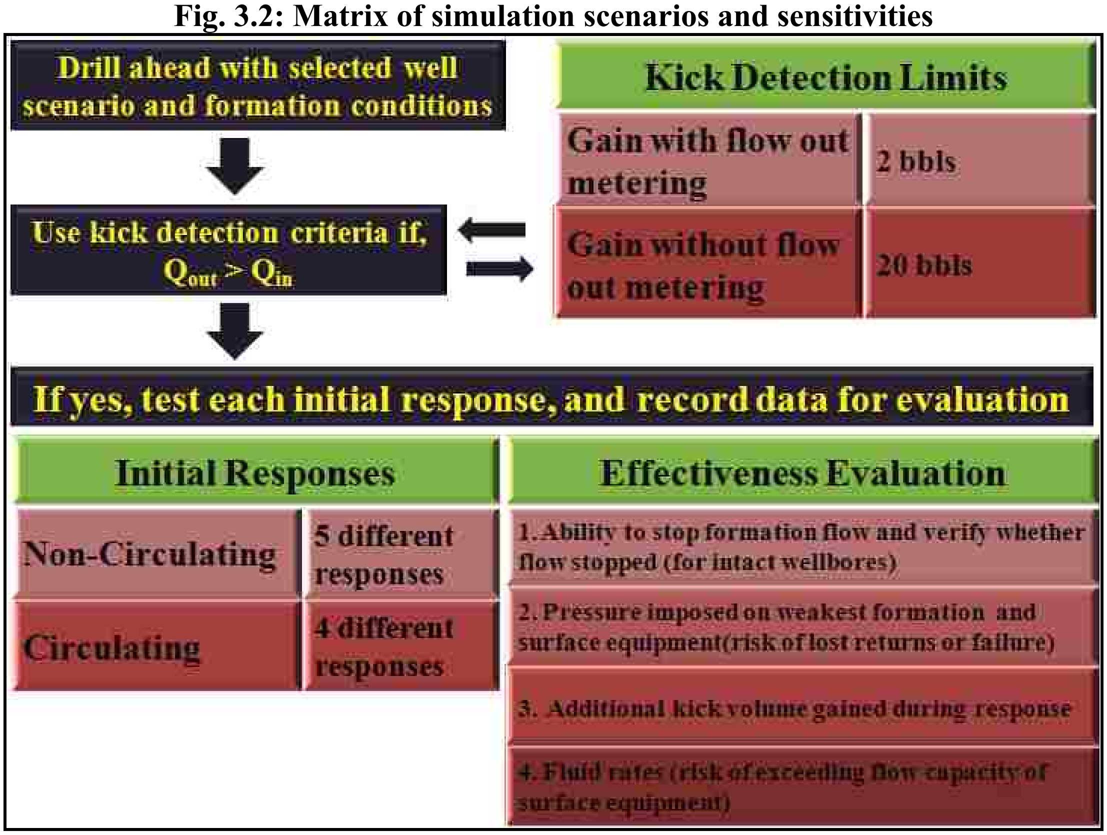


Fig. 3.3: Sequential steps for simulations

3.3 Research Tool

An efficient study of alternative initial responses to kicks is most practical if based on advanced computer simulations. Pressure and temperature changes impact the fluid properties in the downhole conditions and consequently the wellbore pressures. Therefore, advanced hydraulic modeling is required. Additionally, the influx rate from a zone into the well is a transient that depends on the zone's properties and the wellbore pressure. The kick itself creates multi-phase fluid flow in the annulus, including gas migration. Consequently, an advanced dynamic, multi-phase flow simulator is required to simulate well control accounting for these complicated phenomena.

3.4 Dynaflodrill™

Dynaflodrill™ (DFD) is a software application intended to simulate and design UBD applications. It runs under the Drillbench™ engine and includes an advanced, multi-phase, flow model that allows simulation of steady state and dynamic modes as a result of the interaction of influx and drilling fluids accounting for the phenomena described in the previous section[96].

A study of kick influxes and responses to stop those influxes can therefore be performed using DFD. In addition, due to DFD's advanced hydraulics model and the poor results of Ubitts™ validation[91] in the prior study, it was decided to utilize DFD for this research.

3.4.1 Dynaflodrill™ Inputs Parameters

There are multiple input data that should be collected for a representative well before any simulations can be attempted. The main parameters required for DFD simulations are described in this section[97] are the following:

1. Survey data: Measured depth, inclination, and azimuth of all survey stations are entered, and TVD is calculated, using minimum curvature method.
2. Wellbore geometry: Specifications of casing strings, as well as the open hole, are entered.

3. Drillstring: Specifications of drillstring, as well as the drilling bit, are entered.

4. Surface equipment: Choke specifications include inner diameters; duration of the closure and its input (pressure or opening) are collected. For this research, a 3 inch inner diameter for the choke, with 0.5 minutes duration of closure[98] was selected. The choke input parameters will vary based on the way an initial response is applied (refer to Chapter 6). Other significant inputs are the separator working pressure, RCD closure time and liquid pumping rate.

5. Injection system: Drillstring and annulus (parasite and source point) injections are possible. Although this option was used for the software validation, it was not useful for the kick simulations.

6. Mud properties: Specifications of drilling mud are entered, including: fluid type, component density (base oil, water and solid densities as well water/oil ratio), PVT model, and rheology model, including the Fann table or PV and YP. A Black oil PVT model was used throughout the simulations. Rheology models include Bingham, Power law, and Robertson-Stiff. Robertson-Stiff is a three-parameter model, which includes a non-linear flow curve with a yield stress. The Robertson-Stiff model was used for this study based on the validation results in section 3.4.4.2.1.

7. Reservoir conditions: Characteristics of reservoir rock, as well as its fluid, are entered in this section. For any defined zone, the pressure, temperature, porosity, permeability, and influx rate model should be known. The influx rate models available are: constant rate, linear PI, squared PI, and reservoir model. The reservoir model depends on permeability, porosity, drawdown, and the length of the exposed bore. This model was used throughout the simulation study.

8. Temperature: Drillstring and annulus temperature versus depth may be entered in a table.

Optional inputs to DFD are also important for this study. The important ones are:

1. Pressure loss model: Beggs and Brill (for Newtonian fluids); the Semi-Empirical and Mechanistic models are also available. Semi-Empirical model was used for this study based on the validation results in section 3.4.4.2.1.

2. Friction factor model: There are several options, including Colebrook, Dodge-Metzner, Ed. Technip 1982, etc. Dodge-Metzner model was used for this study based on the validation results in section 3.4.4.2.1.

3. Observation points: Up to five positions in the well can be specified for pressure and temperature observations. This is especially valuable for observation of pressure at the bottom and shoe during kick simulation and control.

Examples of input data sets are included as Appendix A and B.

3.4.2 Running Simulations in Dynaflodrill™

Two options are available to control simulations in DFD, interactive and batch modes[97]. In the interactive mode, the user can modify the operational parameters during simulation, which include initial bit depth, liquid flow rate, gas injection rates, ROP, and the choke status. In batch mode however, simulation steps are specified in a table before actually starting a simulation. Later, the whole simulation is performed with no interaction from the user. The results of a simulation can be viewed graphically during the simulation and/or exported in different forms.

3.4.3 Limitations of Dynaflodrill™

Two major limitations in DFD impacted the depth of this simulation based study to some extent. Although pore pressure can be defined for reservoir zones in DFD, a fracture pressure cannot be specified. This means that the wellbore always remains intact, regardless of an infinite pressure buildup in the annulus. This limitation does not allow a study of cases involving lost returns. However, for this initial response study, these are not major limitations. The pressure in the annulus, particularly at a weak zone like a casing shoe, can be monitored for different initial responses. Consequently, the risk associated with each response during stopping a kick can be quantitatively evaluated.

Pit gain, an important kick indicator, was not a direct output in DFD (Version 4), and therefore was calculated using flow rate out and in data after recording that data. Consequently, for the 2 and 20 bbl kick sizes studied in this research, simulations were interrupted to find the correct simulation time required to take the pre-defined kick sizes.

3.4.4 Validation of Dynaflodrill™

A meticulous study, including more than 100 simulation runs, was performed to evaluate the validity of DFD simulation results. Since the outcome of this research was to be used as a basis for well control procedures during the CBHP method of MPD, confidence in the validity of results is important. A summary of the validation study follows this section.

3.4.4.1 Dynaflodrill™ Validation Method

Simulation of alternative initial responses to gas kicks requires a robust engine. Consequently, a useful validation of DFD not only should examine its ability to reasonably simulate steady state modes, it should also predict soundly transient state modes.

1. Steady state: In this phase of DFD validation, the normal circulation of mud in a geometrically known flow conduit could be simulated and frictional pressure loss predictions verified versus the real data. Fortunately, historic data of tests done at the well LSU#1, as well as more comprehensive tests done by Amoco Production Company[99] at the well LSU#2, provided an opportunity to construct these well geometries in DFD and compare the results of simulations to the real data. Several steady state circulations of weighted and unweighted drilling fluids were available. The frictional pressure losses could also be checked versus theoretical predictions[4].

2. Transient state: In this phase of DFD validation, gas migration and kick circulation could be simulated in DFD and the results, such as pit gain and drill pipe pressure, verified versus the real data. Several transient state tests of simulated gas kicks with weighted and unweighted drilling fluids at the LSU#2 well were available as well[99].

3.4.4.2 Description of the Steady State Validations

The LSU#1 and LSU#2 well geometries were constructed in DFD. A description of the wells and the historic data used for validation are introduced in this section:

1. LSU#1 is a vertical well with a depth of around 3000 ft and three different size annuli. Pump pressure data at several flow rates was available for an 8.4 ppg almost Newtonian WBM. A schematic of the LSU#1 well is included in Appendix D.
2. LSU#2 is a vertical well with 3.5" tubing inside 9.625" casing at a depth of around 6000 ft. Pump pressure data at several flow rates was available for four selected sets of WBM from 8.6 to 12.4 ppg. The rheology of these drilling fluids followed the Power law rheology model well. A schematic of the LSU#2 well is included in Appendix E.

The majority of available settings in DFD were alternated during simulations of each data set from LSU#1 and LSU#2. These include: 3 different mud rheology models (Bingham, Power law and Robertson-Stiff), 2 different pressure loss models (Mechanistic and Semi-empirical) and 3 different friction factor models (Colebrook, Dodge-Metzner, and Ed. Technip 1982), with two different pipe roughnesses for sensitivity checks. After entering a set of mud data and different models in DFD, the flow rate was increased to match the real data and accordingly, the pump pressure was recorded for evaluation process. This was repeated for all cases. The same simulations were also repeated using Ubitts™ (versions 2.9 and 3.0), which employs a very simplified rheology model and with independent hand calculations, using Colebrook's and Dodge-Metzner equations[4] for the LSU#1 and the LSU#2, respectively.

3.4.4.2.1 The Results of Steady State Validations

A summary of the results of the steady state simulations is shown in Table 3.1. The overall results indicate that the selection of friction factor and rheology models impacted the DFD results. For Newtonian fluids, however, the results were identical with all of rheology models, but the Colebrook friction factor model showed the smallest error. For high rheology fluids, the Robertson-Stiff rheology model and the Dodge-Metzner friction factor model showed less than a 6% error consistently. The other friction factor models' predictions were not as consistent and typically had larger errors. Ubitts™ also demonstrated inconsistently and larger errors.

No significant difference was observed between pressure loss models in the steady state validation. Therefore, Robertson-Stiff as the rheology model, Dodge-Metzner as the friction factor model, and semi-empirical as the pressure loss model were concluded to be the proper settings for this research, although not all of these settings were recommended by the software developers.

Table 3.1: Steady state error ranges between DFD predictions and the real data from LSU#1 and LSU#2

	Mud (n, k)	Theory	Ubitts™	DFD, R-S		
				C-B	D-M	Ed-T
LSU#1	PV=1 YP=0 8.4 ppg	4-9	11-22	6-11	23-28	14-20
LSU#2	0.839, 27.33 8.6 ppg	0.3-0.4	5-6	5-6	2-3	0-2
	0.814, 77.84 12.4 ppg	0-1	7-8	7-8	3-5	5-6
	0.739, 239.83 12.3 ppg	7-8	13-16	20-21	5-6	0-3
	0.638, 423.23 8.7 ppg	1-3	3-5	12-14	3-5	11-13

3.4.4.3 Description of the Transient State Validations

The validated DFD models from the steady state simulations were entered in the DFD input parameters as the default settings. In order to validate the multi phase flow behavior of DFD, a gas migration test data set was chosen. In the original test, Nitrogen gas was injected in the bottom of LSU#2, and then choke was adjusted in an attempt to keep the BHP constant. The choke and pump pressure, as well as pit gain were recorded versus time in one minute increments. The following steps were followed in DFD to simulate this case:

1. The given WBM of 8.6 ppg with available Fann data was entered in DFD.
2. Nitrogen gas was injected in the bottom of LSU#2 at 1200 Scf/min to get the same initial gain of 8 bbls.
3. The choke pressure data versus time was entered in DFD, using the batch mode.
4. The simulation was started and drill pipe pressure and pit gain were observed while gas migrated in the annulus. The results were saved for the evaluation analysis.
5. Since Ubitts^{TM} does not allow batch mode simulation, the same process was performed using interactive option. The results were also saved.

3.4.4.3.1 Results of the Transient State Validations

The simulation results of the gas migration in DFD and Ubitts^{TM} for the case described above are plotted in Fig. 3.4 and Fig. 3.5. As can be seen from the choke pressure data, the batch mode option in DFD allowed more accurate history matching, compared to Ubitts^{TM}. In both simulations, the drill pipe pressure was lower, and the pit gain was larger than the real data. This shows that neither simulator predicted gas migration accurately. It also implies that both simulators underestimated the gas dispersion in the annulus. Moreover, comparison of DFD gain versus the real gain, reveals that the average gas velocity in the annulus was pretty reasonable, but that the gas surfaced much later in the simulation. The same comparison for Ubitts^{TM}

indicates that average gas velocity was higher, and the gas surfaced very early. Two other gas migration and kick circulation simulations showed similar results[100]. The results pertaining to gas migration and kick circulation would impact the accuracy of a full kick circulation study in DFD. However, for the study of the initial responses represented by the first 20 to 30 minutes of these tests, the accuracy of the DFD predictions are more than acceptable.

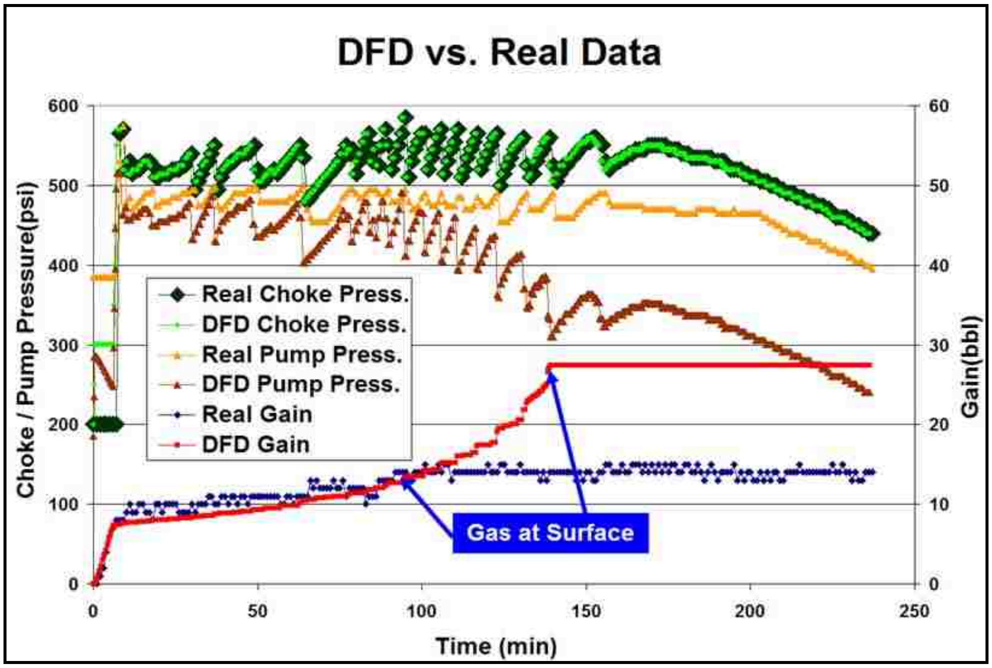


Fig. 3.4: Comparison of gas migration results of DFD versus real data from LSU#2

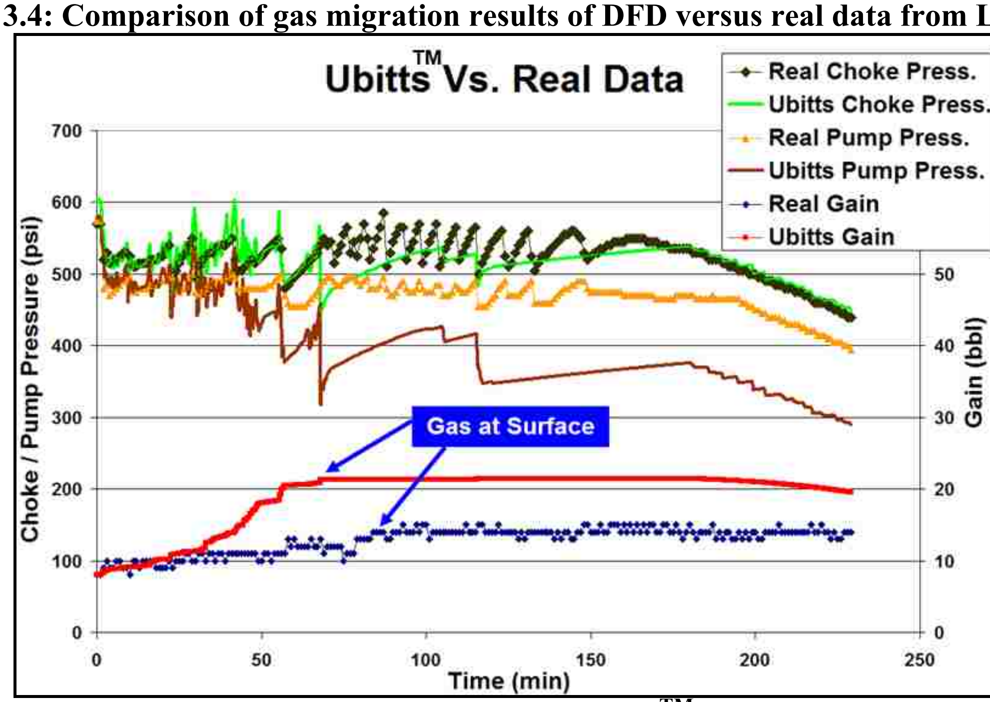


Fig. 3.5: Comparison of gas migration results of Ubitts™ versus real data from LSU#2

3.4.4.4 Dynaflodrill™ Validation Summary

DFD was selected for this research rather than Ubitts™ because DFD demonstrated acceptable simulations of steady state and transient conditions versus real data. Additionally, its more flexible user interface, supporting both interactive and batch inputs, allows efficient and repeatable simulation of the alternative initial responses. This further provides an opportunity to compare and evaluate the results more effectively.

4. WELL GEOMETRIES

4.1 Introduction

Slim hole and large hole wellbores were defined for use in evaluating alternative initial responses to kicks for a broad spectrum of possible MPD applications. Therefore, a 6" well (Well X) and a 17 ½" (Well Z) well were selected. The detailed simulator input data for Well X and Well Z base cases (no kick cases) are given in Appendix A and B. A general description of each well follows.

4.2 Well X

The objective of the MPD application represented by Well X is to produce from a mature reservoir where redevelopment with conventional drilling had not been successful mainly due to severe loss of returns. The well is an offshore sidetrack from a window milled in an existing 7" liner. Fig. 4.1 and Table 4.1 show the directional profile and summary description of Well X.

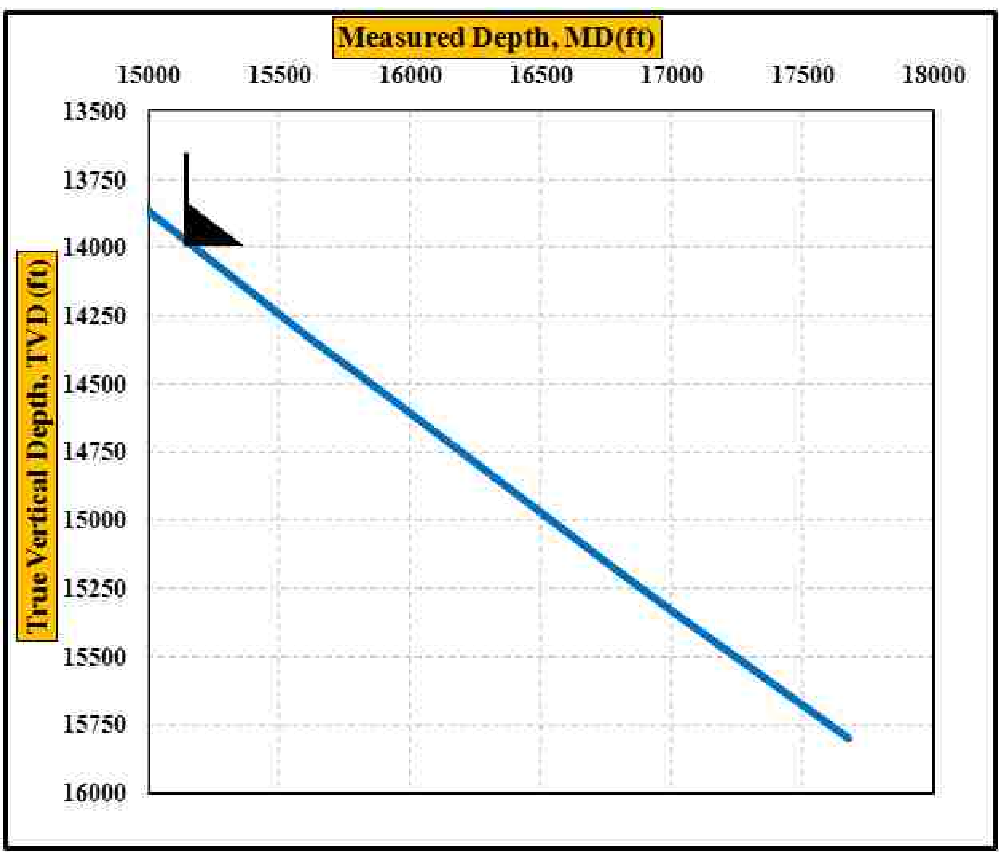


Fig. 4.1: Well X directional profile plot

Table 4.1: Well X data summary

Well type	Re-entry, sidetrack
Well objective	Produce from deeper sand
Reservoir fluid	Gas condensate
Well profile	Directional with max. 46° inclination
Rotary table elevation	170 ft
Water depth	2862 ft
Mud line	3032 ft
Top of window (shoe)	15150 ft (13979 ft TVD)
TD	17675 ft (15800 ft TVD)
Hole size	6 in
Max. Bottom Hole Temperature (BHT) at TD	170° F
Min. BHT (at shoe)	145° F

Figure 4.2 depicts a simplified plot of pore pressure and fracture pressure profiles of Well X. The re-entry operation in such a slim wellbore is usually characterized by high AFP, which increases the ECD and therefore, requires careful hydraulics planning, especially in a narrow drilling margin. This planning was more complicated for Well X as the high pressure sand at 16265 ft (14800 ft TVD) required a mud weight of at least 13.7 ppg to avoid taking kicks. In addition for the interval shown, a minimum of 13.8 to 14.1 ppg mud weight was required for well stability purposes due to shale overburden.

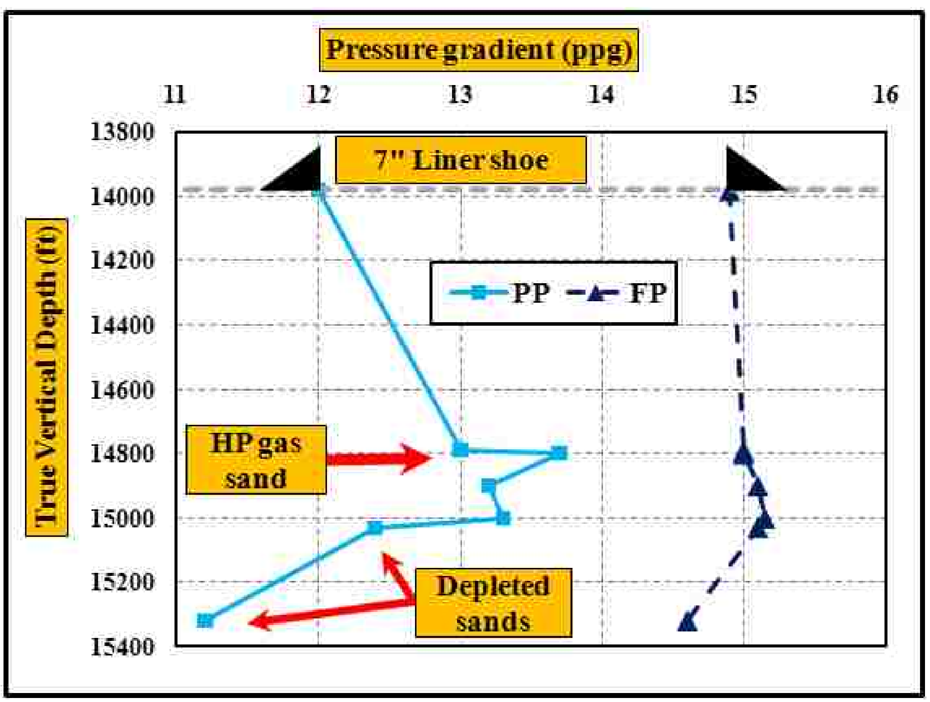


Fig. 4.2: Well X 6” section PP-FP gradient profiles

An ECD effect of 1 to 1.2 ppge was expected while drilling, based on P_{AF} losses calculated with hydraulics modeling. Therefore, a mud weight that would avoid hole stability problems while static would be likely to cause lost returns either at the shoe or in the deeper, partially depleted sands, when circulating. Fig. 4.3 shows a simplified schematic of Well X, where relative location of high pressure sand to the shoe and TD, as well as BHA components, can be noted.

In order to reduce the dynamic overbalance on the shoe and depleted zones, a precise wellbore pressure management technique was required. This could be realized by application of the CBHP method of MPD, where a smaller static mud weight is selected, and a combination of ECD and surface back pressure contribute to keep the target BHP constant during drilling and pipe connections.

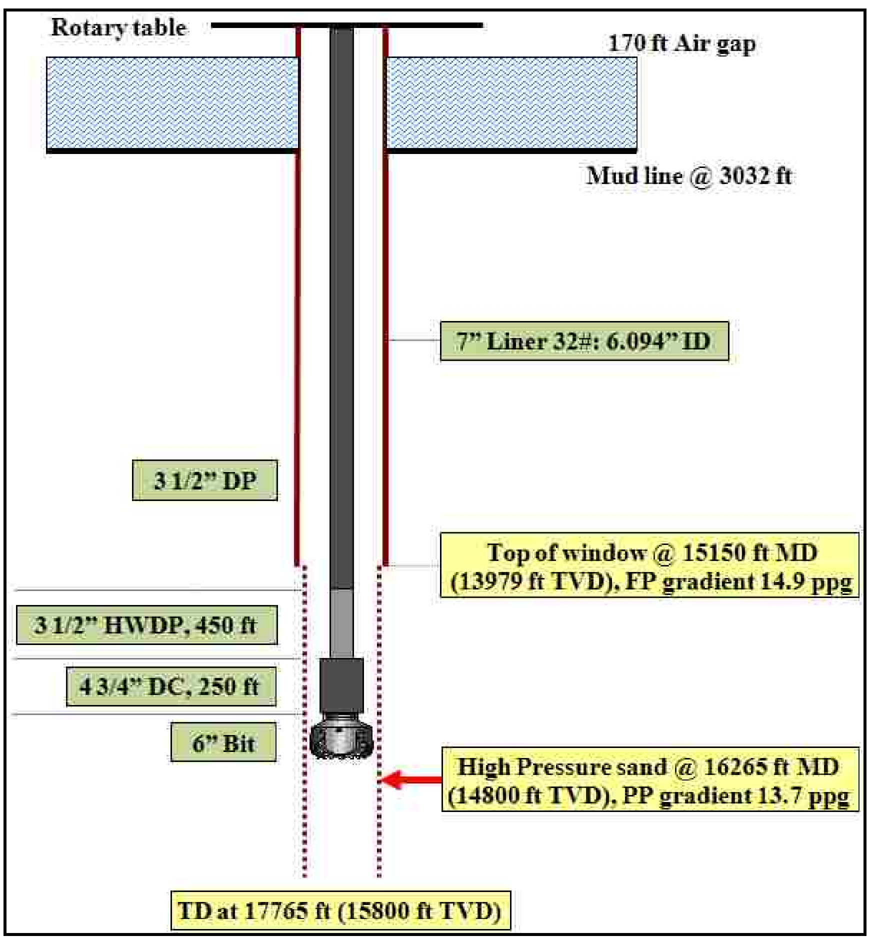


Fig. 4.3: A simplified schematic of Well X

4.2.1 Well X Operational Settings

Hydraulics modeling had suggested a static mud weight of 13.2 ppg be used for drilling Well X in order to keep the BHP between 14.2 to 14.4 ppge while circulating. These circulating conditions gave a predicted ECD of 13.91 ppge using DFD. This ECD (BHP of 10,710 psi at 14800 ft TVD) became the target BHP that should be kept constant just before drilling into the HP sand, using the CBHP method. Key operational inputs that remained constant throughout the simulations are listed in Table 4.2.

Table 4.2: Well X Operational Settings

Drilling flow rate	190 GPM
Bottoms-Up lag time at the top of the HP sand (at 16265 ft)	~ 86 minutes
Mud type	WBM
Mud weight	13.2 ppg
Mud rheology	Refer to Appendix A
Bit nozzles, Total Flow Area (TFA)	4 x 11/32”, 0.37 in^2
Drilling rate	60 ft/hr
Shoe fracture pressure	14.9 ppg equal to 10831 psi
ECD at shoe (at 190 GPM)	13.75 ppge equal to 10,000 psi
ECD on bottom (at 16265 ft and 190 GPM)	13.91 ppge equal to 10,710 psi
Annular Frictional Pressure Loss (P_{AF})	520 psi
HP sand at	16265 ft MD (14800 ft TVD)
HP sand thickness	100 ft
Kick margin	(14.9 – 13.75) = 1.15 ppge
Max. Allowable Annular Surface Pressure (MAASP)	(0.052 * 13979 * 1.15) = 836 psi
Max. allowable Standpipe pressure	6000 psi
Choke inner diameter	3 inches

4.2.2 Well X Kick Scenarios

Drilling into the deeper, depleted sands (per Fig. 4.2) is further complicated by the risk of lost returns at those zones, which in turn trigger kicks at the shallower HP sand, as studied by Das[91]. The complication of taking a kick and the possible risk at the casing shoe is the focus of this study (Chapters 2 and 3). For any predefined formation pore pressure and permeability, bit depth is set just above the HP sand at 16260 ft, and drilling would initiate at 60 ft/hr. The bit would drill into the HP sand at 16265 ft, where gas kicks would be taken. Drilling continues at the same rate until a surface pit gain of 2 bbls is achieved, equal to the assumed sensitive kick detection limit. At this moment the simulation is stopped, and the file is saved for the test of different initial responses as defined in Chapter 5. Then, the effectiveness of these responses is evaluated by means of the road map explained in Chapter 3. The whole work is repeated for 20 bbls of gain, equal to the assumed typical kick detection limit, in the same manner.

Formation pore pressure is varied to define a total of 3 different cases of BHP, dynamically underbalanced with different severity. The method to calculate these formation pressure gradients is explained in Chapter 3, and given by Eq. 4.1. Kick intensity or underbalance severity may also be determined by application of Eq. 4.2. The values of X used in Eq. 4.1 are 20%, 60%, and 120%. Unfortunately, the 20% case only provided 0.01 ppge of dynamically underbalanced pressure, which in turn generated a very small kick, which was deemed insignificant. It was decided to create a higher, underbalanced case to achieve almost 0.1 ppge of dynamically underbalanced pressure. This is obtained by applying 25%, rather than 20% in the Eq. 4.1. There is no kick for the base case upon drilling in the HP sand, with the drilling parameters given in Table 4.2 and planned formation pressure, P_{fp}. A list of all the different pore pressure scenarios is given in Table 4.3.

Table 4.3: Well X Kick Scenarios (13.2 ppg mud at 190 GPM)

	No Kick Case	**X = 25%**	**X = 60%**	**X = 120%**
P_{fp} gradients (ppg)	**13.70**	**13.70**	**13.70**	**13.70**
Kick margin (ppge)	**1.15**	**1.15**	**1.15**	**1.15**
P_f gradients (ppg)	**13.70**	**14.00**	**14.39**	**15.08**
P_f used in simulations (psi)	**10544**	**10774**	**11075**	**11606**
Kick intensity (ppge)	**0.2 OB**	**0.1 UB**	**0.5 UB**	**1.2 UB**

$$P_f = P_{fp} + X * (Kick\_margin) \quad \text{(Eq. 4.1)}$$

$$Kick\_Intensity = \frac{(P_f - BHP)}{(0.052) * (TVD_{HP\_Sand})} \quad \text{(Eq. 4.2)}$$

The 3 different underbalanced cases, 2 different reservoir permeabilities, 2 different kick detection limits and 9 alternative initial responses result in a total of 108 simulations for Well X simulations to 108 runs. These runs and their results will be discussed in the next chapter.

4.3 Well Z

Well Z represents a vertical exploratory well, planned to drill to a gas / oil sand at 11480 ft MD. A narrow PP-FP window caused the drilling of the 17.5” section to be especially challenging. Consequently, Well Z is a potential MPD application. The objective of 17.5” section was to drill to the planned 16” casing shoe, in a depth of 4756 ft. The well is offshore, and 20” casing is cemented at 3280 ft. Table 4.4 gives summary information about the 17.5” section of Well Z.

Table 4.4: Well Z 17.5” data Summary

Well type	Exploratory
Well objective	Drill to a gas / oil sand at 11480 ft MD
Well profile	Vertical
Rotary table elevation	140 ft
Water depth	115 ft
Mud line	255 ft
Casing shoe	3280 ft MD / TVD
Hole size	17.5 in
Section TD	4756 ft MD / TVD
Drilling fluid	WBM
Max. BHT (at section TD)	130° F
Min. BHT (at shoe)	98° F

Figure 4.4 depicts a simplified plot of the pore pressure and fracture pressure profiles of the 17.5” section of Well Z. As can be seen, the formation pore pressure gradient rapidly increases from 8.74 ppg at 3280 ft (20” casing shoe) to 13.49 ppg at 4756 ft (TD of 17.5” section). This quickly reduces the drilling window and simultaneously, increases drilling related problems such as differential sticking and possible loss of returns at the shoe. The fracture pressure gradient of 20” casing shoe is 14.16 ppg, and a mud weight of at least 13.49 ppg is required (with no trip margin) to safely drill to the section TD. This leaves the ultimate drilling

window to be narrow, 0.67 ppg. Although a mud as heavy as 13.6 ppg would safely drill to the section TD, the potential for a higher pressure gas sand in this exploratory well makes this interval particularly interesting for evaluation of the sensitivity of initial kick responses to hole size.

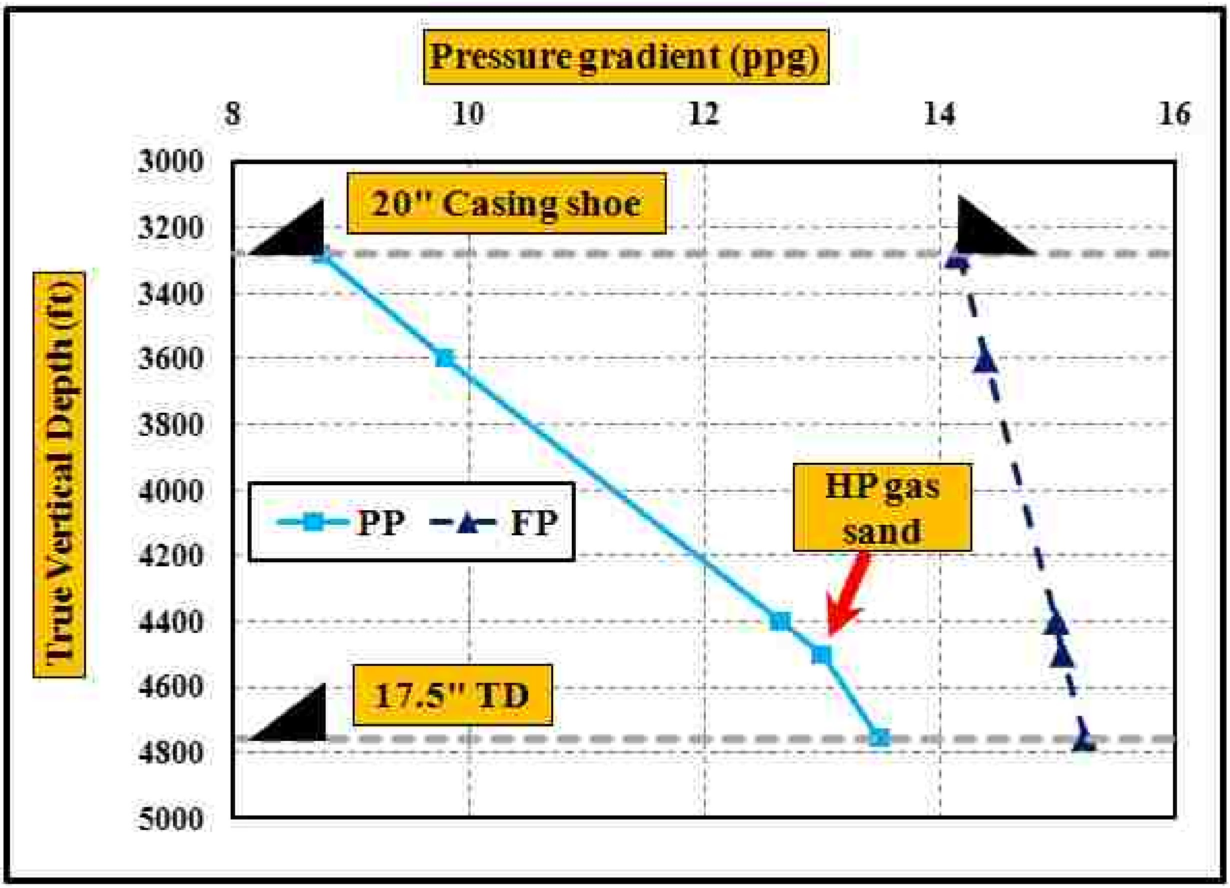


Fig. 4.4: Well Z 17.5" section PP-FP gradient profiles

Uncertainty of the presence, pore pressure and depth of HP sands implies an advantage of using precise wellbore pressure management. Consequently, this could be realized by application of the CBHP method of MPD. Since there is minimal annular friction in this large hole section, using a minimal static overbalance drilling fluid while applying surface back pressure could combine to keep the target BHP constant during the drilling and pipe connection.

Fig. 4.5 shows a simplified schematic of Well Z, where the relative location of a potential high pressure sand to the shoe and TD, as well as BHA components, may be noted.

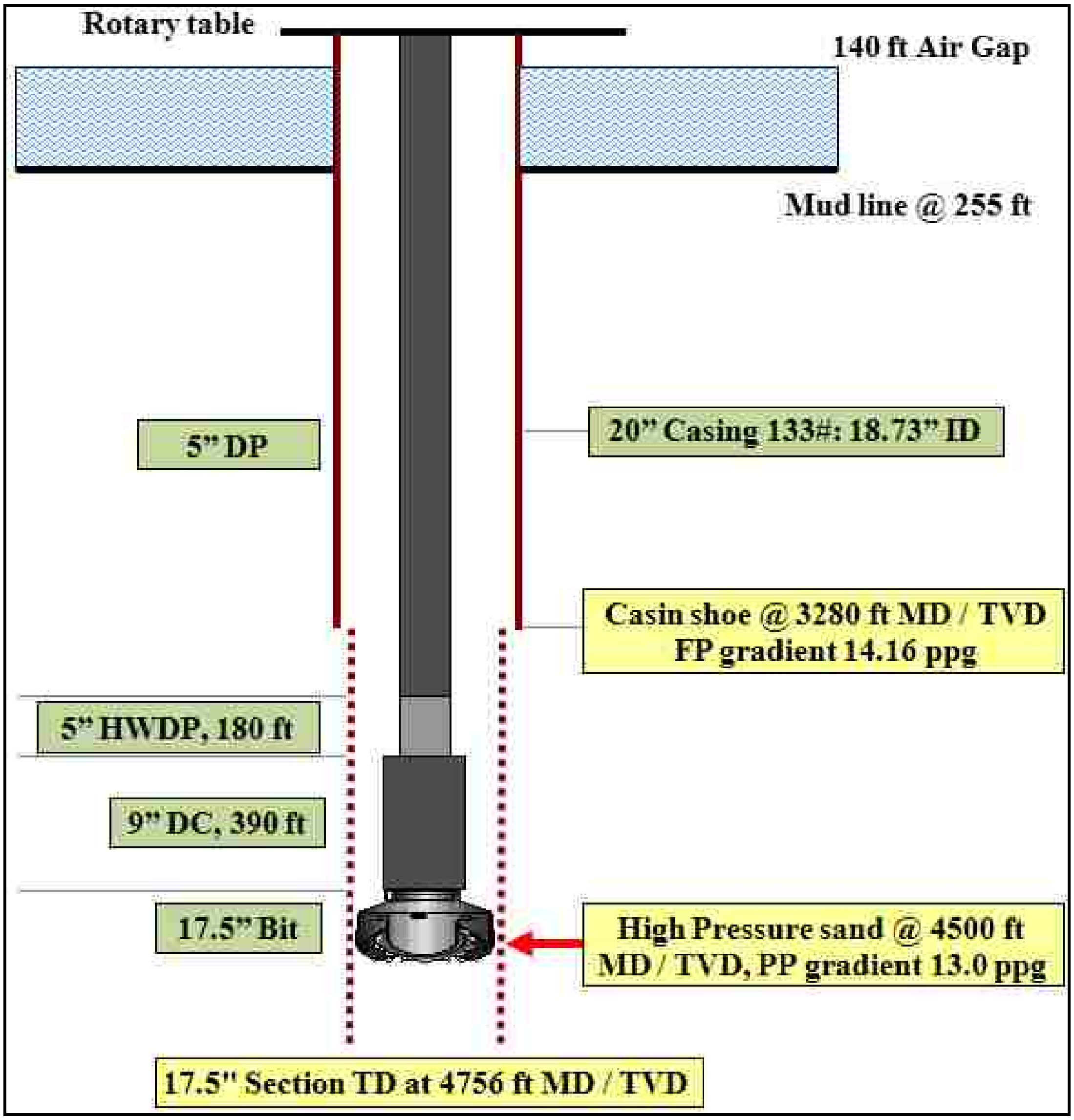


Fig. 4.5: A simplified schematic of Well Z, 17.5" section

4.3.1 Well Z Operational Settings

A static mud weight of 13.1 ppg is required for the objective of drilling through the HP sand of the Well Z. This statically overbalanced mud weight provides the base case to be a "no kick case," as well. A mud pumping rate of 900 gpm provides only an ECD of 13.12 ppge (or BHP of 3070 psi), which in turn becomes the target BHP that should be kept constant just before drilling into the HP sand, using an application of the CBHP method. Some key operational inputs remain constant throughout the simulations; these are listed in Table 4.5.

Table 4.5: Well Z Operational Settings

Drilling flow rate	900 GPM
Bottoms-Up lag time at the top of the HP sand (at 4500 ft)	~ 63 minutes
Mud type	100% WBM
Mud weight	13.1 ppg
Mud rheology	Refer to Appendix B
Bit nozzles, Total Flow Area (TFA)	3 X 18/32", 0.75 in^2
Drilling rate	60 ft/hr
Shoe fracture pressure	14.16 ppg equal to 2415 psi
ECD at shoe (at 900 GPM)	13.15 ppge equal to 2243 psi
ECD on bottom (at 4500 ft and 900 GPM)	13.12 ppge equal to 3070 psi
Annular Frictional Pressure Loss (P_{AF})	5 psi
HP sand at	4500 ft MD / TVD
HP sand thickness	256 ft
Kick margin	(14.16 – 13.15) = 1.01 ppge
Max. Allowable Annular Surface Pressure (MAASP)	0.052 * 3280 * 1.01 = 172 psi
Max. allowable Standpipe pressure	6000 psi
Choke inner diameter	3 inches

4.3.2 Well Z Kick Scenarios

The complication of taking a kick and the risk of losing returns at the casing shoe will be the focus of this study (refer to the chapter 2 and 3). Here, for any predefined formation pore pressure and permeability, the bit depth is set just above the HP sand at 4495 ft; drilling is commenced at 60 ft/hr. The bit drills into the HP sand at 4500 ft, where gas kicks are taken. Drilling continues at the same rate until a surface pit gain of 2 bbls, equal to the assumed sensitive kick detection limit, is obtained. At this moment the simulation is stopped, and the file is saved for the test of different initial responses defined in Chapter 5. Then the effectiveness of these responses is evaluated by means of the road map explained in Chapter 3. The whole work is repeated for 20 bbls of gain, equal to the assumed typical kick detection limit.

Formation pressure gradients are calculated using Eq. 4.1, as explained for the Well X. The values of X used in the Eq. 4.1 are 20%, 60%, and 120%. Unfortunately, the 120% case only provided 1.1 ppge of dynamically underbalanced pressure, and consequently was changed to

130% to obtain the same severity of 1.2 ppge. There is no kick for the base case. The list of different pore pressure scenarios is provided in Table 4.6.

Table 4.6: Well Z Kick Scenarios (13.1 ppg mud at 900 GPM)

	No Kick Case	X = 20%	X = 60%	X = 130%
P_{fp} gradients (ppg)	**13.00**	**13.00**	**13.00**	**13.00**
Kick margin (ppge)	**1.01**	**1.01**	**1.01**	**1.01**
P_f gradients (ppg)	**13.00**	**13.20**	**13.60**	**14.31**
P_f used in simulations (psi)	**3042**	**3089**	**3184**	**3349**
Kick intensity (ppge)	**0.1 OB**	**0.1 UB**	**0.5 UB**	**1.2 UB**

The negligible annular frictional pressure losses for Well Z eliminate the necessity of simulations for those alternative initial kick responses that stop kicks by the manipulation of friction in the annulus. This reduces the total number of initial responses for Well Z to four responses. Therefore, the total number of Well Z simulations drops to just 48 runs. These runs will be discussed in the next chapter.

5. ALTERNATIVE INITIAL RESPONSES

5.1 Introduction

Initial responses to kicks are the immediate activities taken by a rig crew that are intended to stop an influx of fluids from a permeable formation into a well. The success of an initial response is very critical to controlling the well. If a kick volume gets larger due to an improper initial response, it can eventually complicate the subsequent kick circulation and control procedures. For example, excessive pressure will be developed in the annulus to compensate the larger loss of hydrostatic pressure caused by a larger kick. This situation can be a potential threat to surface equipment and to the well itself.

The success of an initial response to a kick also depends on several other factors, including but not limited to a) well design, b) kick detection limits, c) rig equipment ratings, and d) the rig crew's experience. Designing a well for MPD type operations in narrow drilling margins tends to reduce the number of casing strings required. This can allow the well to reach TD with an appropriate bore size for efficient production. However, the resulting small kick margin implies an inherent limitation of well design for these operations. In addition, the IADC UBO/MPD committee has HSE and well control guidelines for rig personnel when attempting these kinds of operations. There may be limitations to the rating of equipment based on anticipated well requirements. Ultimately, with these constraints the importance of a proper initial response is critical.

The kick scenarios investigated in this study are those taken during drilling into a permeable formation that contains a higher PP than expected. This class of kick incidents still carries a major potential for occurrence during MPD operations, which aim to drill faster in trouble zones for fewer interruptions. The other classes of kicks include off-bottom kicks, kicks due to failed equipment, and kicks from upper high pressure zones due to loss of returns on bottom. These kicks are not considered in this research.

There are additional approaches for increasing the BHP and stopping an influx during the CBHP method of MPD besides those used in conventional drilling. In conventional drilling, as mentioned in Chapter 1, Shut-In (SI) of the well is essentially the only way to stop kicks. In this simple method, there is no ECD after mud pumps are shut down. Permeable formation fluid enters into the wellbore building up pressure in the annulus as soon as annulus is closed. This continues until enough BHP is achieved to balance the zone PP. In the CBHP method, however, the well is closed by the RCD, and mud flows through the DCM. Thus, a SI response can also be realized by closing the choke. Other applicable mechanisms in the CBHP method that can potentially increase BHP and stop an influx are to apply surface back pressure and to increase the ECD or a combination of both.

A total of nine alternative initial responses were finally defined to investigate the best alternative initial responses to gas kicks taken during drilling in the CBHP method of MPD operations. These may be divided into two major categories based on the mechanism by which they stop an influx. These categories are non-circulating and circulating responses. In the following sections, the initial responses, respective to each category, will be described and for each, a simulation example is shown to demonstrate the use of that response in DFD.

5.2 Non-Circulating Responses (NCRs)

Five NCRs that are studied in this research will be described in this section. All of these initial responses end up with the well SI, and since there is no mud circulation, these are categorized as non-circulating responses. The well can be SI either by application of RCD and the choke or by closing the BOP directly. If the pressure rating of the RCD is not sufficient, then closing the rig BOP is the only logical non-circulating solution.

One of the major benefits of applying the NCRs to any kick scenario is the ability to directly determine the real formation PP from interpreting the stabilized casing and drill pipe pressures after a SI. However, if a NRV is used in the BHA, as is usually the case with MPD operations, then it is required to bump the float to realize a relevant drill pipe pressure for the interpretation. Another fact about the NCRs is an inherent ability to ultimately stop any influx as long as the wellbore remains intact.

In a sealed and pressurized annulus, an influx may continue after the initial SI; however, it will only continue until the increasing BHP balances out the kick zone PP. Another benefit of Non-Circ responses lies in the fact that they do not require accurate surface mud flow rate-out (Q_{out}) metering before they can be applied to a kick.

A proper pump start up procedure must be commenced after determination of the SI casing pressure required to stop formation flow in all of the NCRs. This is a necessary procedure before any kick circulation activity can be stated, which unfortunately can increase NPT. Another drawback of the NCRs is the immediate need to start the kick control procedure. This is especially serious in the case of gas kicks in WBM, which are the focus of this study, and are usually referred to as worst case scenarios. As the gas starts to migrate to the surface, casing pressure (P_c) continues to increase, and if no action is taken, it can potentially exceed the rating of the surface equipment, the casing design limits, or the fracture pressure of any weak zones in the well.

The NCRs studied in this research are: SI; MPD pump shut-down (SD) with (W)/ choked flow check (CFC) and SI; MPD pump SD and SI; automated (Auto) MPD pump SD W/ CFC and SI; and Auto MPD pump SD and SI. All of the NCRs are applicable to Well X. For Well Z, however, due to a lack of significant P_{AF} to construct the MPD pump SD schedule, the NCRs simply reduce to SI.

5.2.1 Shut-In (SI)

The SI response is definitely the most recognized response to kicks in the entire petroleum industry. Any time there is uncertainty in well control aspects, the conventional drilling wisdom instructs the drilling crew to stop the mud pumps, do a flow check, and then SI the well. In MPD operations, where the annulus is already closed with the RCD, a flow check will show that the formation is flowing if the well is statically underbalanced and therefore is unnecessary and inappropriate.

A simple method of shutting down the mud pumps and then closing the choke as fast as is practical is therefore a useful adaptation of conventional SI for MPD operations. The American Petroleum Institute[98] (API) requires that 30 seconds be enough for a choke throat to be fully closed. The SI schedule shown on Table 5.1, which looks like a conventional hard SI without a flow check, was defined and applied in the batch mode in DFD simulations; the process allowed all of the simulated cases to be consistent. Several practices and demonstrations at the LSU well facility with standard rig equipment demonstrated that the whole schedule could be repeated within much less than 1.1 minutes.

Table 5.1: SI schedule

Shut down the mud pumps	0.5 min
Closing the choke	0.5-0.6 min

5.2.1.1 Example of SI Response

Fig. 5.1 shows an application of SI response on a 2 bbl kick taken after drilling into the Well X HP sand at 16265 ft MD with 500 mD permeability (high k). Drilling into this zone creates a circulating UB of 0.5 ppge at a drilling rate of 190 gpm. An accurate kick monitoring device was assumed to be available, which allowed early kick detection.

A kick is recognized by the increase of the surface mud flow rate-out (Q_{out}), as shown by the arrow. Drilling was stopped, and the mud pump was shut down when pit level confirmed 2 bbls of gain. Afterwards, the choke was closed according to the schedule displayed in Table 5.1. Casing pressure consequently increased to balance the kick zone's pressure. This is affirmed by the choke pressure curve that "stabilized" at around 1100 psi. Hence, BHP increased and surpassed the formation pressure at the point shown by the green marker. At this point, the formation influx stopped, and therefore this initial response was successful.

The slow rate of the choke pressure increase seen after this point indicates that gas migration is occurring in the annulus. About 5 bbls of extra kick volume was taken after commencing the SI response, until the choke was fully closed; thus, a total pit gain of 7 bbls remained constant for the rest of the simulation of the initial response. BHP, formation pressure, and the choke opening were divided by ten before plotting in order to allow better clarity and use of one scale.

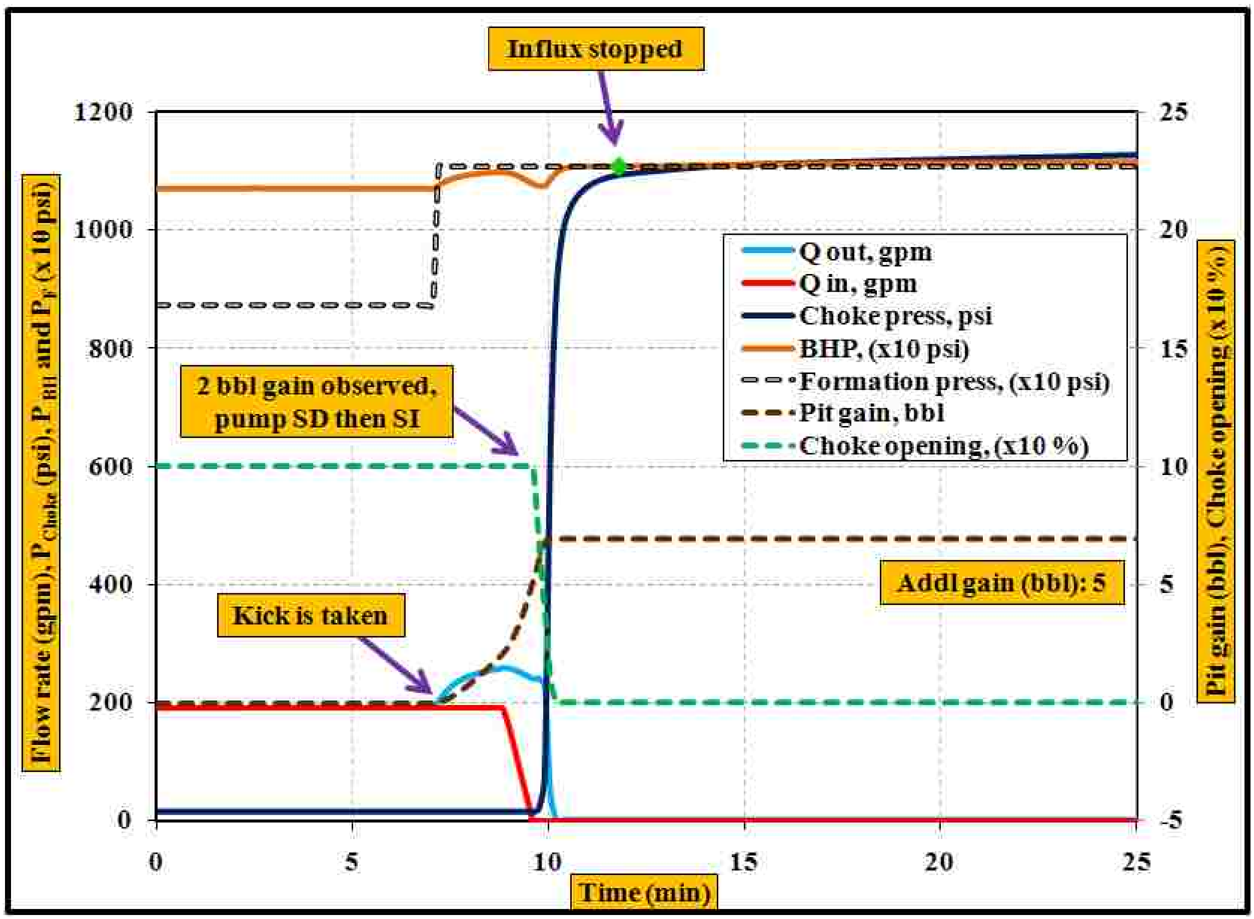


Fig. 5.1: Well X, application of SI on 2 bbl kick / high k / 0.5 ppge Circ UB

5.2.2 MPD Pump SD W/ CFC and SI

The MPD pump SD W/ CFC and SI response commences with the CBHP method's proper pump shut-down schedule. This particular initial response, intended to simulate a manual form of pump shut-down, follows a step-wise pump schedule discussed in Chapter 2. At the end of the schedule, the P_c that is required to compensate for the lost P_{AF} is held constant for two minutes before shutting the well in, unless SI is required to maintain this P_c. This provides an opportunity to check whether the pre-calculated P_c is enough to stop formation flow. If not, the well will flow, and this particular practice serves the purpose of a flow check in conventional operations. Since the choke may not be fully closed during this period, yet the flow conduit was restricted, it was decided to call this part of the schedule a "choked flow check" or "CFC" for descriptive purposes. The required P_c may be achieved either by trapping the pressure in the well through manipulation of the choke or by using the choke and a dedicated back pressure pump to impose pressure on the well.

This method ending in SI has the benefits and drawbacks common in all NCRs that were previously discussed but is obviously slower than a simple SI. Its advantage is to confirm whether the planned P_c will, in fact, control the well. Table 5.2 shows an 11.5 minute step-wise schedule until the well was SI; this schedule was constructed with the knowledge that the choke on a typical MPD job may not be semi or fully automated. As a result, some MPD pump SD schedules have required 10 to 15 minutes to perform. In such cases, the schedule must be manually achievable for the mud pump and choke operators. 15 minutes were added to all simulations In order to monitor the pressure build ups and interpret the stabilized pressure data. This schedule was applied to all Well X kick scenarios with this response for consistency. In practice, the SD should be conducted quickly and may be completed in as little as 2 to 3 minutes.

Likewise, the SI monitoring period should only be long enough to determine that formation flow has stopped, allowing a stabilized P_c to be determined.

Table 5.2: Schedule for MPD pump SD W/ CFC and SI for Well X

Time (min)	Mud Flow in (gpm)	RCD	Choke	P_c (psi)	Comments
1	190	Closed	Open	100	MPD pump SD
1	168	Closed	Open	100	
1	168	Closed	Open	200	
1	139	Closed	Open	200	
1	139	Closed	Open	300	
1	107	Closed	Open	300	
1	107	Closed	Open	400	
1	49	Closed	Open	400	
1	49	Closed	Open	520	
2	0	Closed	Open	520	"choked flow check"
0.5	0	Closed	Closed	Buildup	SI
15	0	Closed	Closed	Buildup	SI, Monitor

5.2.2.1 Example of MPD Pump SD W/ CFC and SI

This initial kick response, with the schedule shown in Table 5.2, was applied on the 2 bbl kick from the Well X HP sand at 16265 ft MD with a high k and the Circ UB of 0.5 ppge (the same kick scenario shown for the SI example). Results are shown in Fig. 5.2. After the initial gain of 2 bbls, drilling was stopped. The MPD pump SD was implemented, which resulted in keeping the choke pressure constant for 2 minutes (choked flow check or CFC), followed by SI.

This practice replaces the P_{AF} with an equivalent non-circulating back pressure, in order to keep the BHP constant. This is true when there is no kick and therefore the flow rate out closely follows the flow rate in as per the schedule, thus generating a “no kick fingerprint.” This so-called fingerprint can be recorded or modeled before drilling, and then compared to the actual flow rate out response as a sensitive kick detection method. For the no kick case ideally, no mud should be bled through the choke during the CFC; neither should a choke pressure build-up be seen. The simulated no kick choke pressure curve confirmed this statement. However, the no kick Q_{out} curve shows that actually a small amount of mud had to be bled initially, at about 18.5

minutes before closing the choke completely, to allow the target choke pressure during the CFC to be achieved.

If a kick is taken as seen on the plot, however, the back pressure (520 psi) during the CFC was not enough to contain the pressure of the HP sand. Therefore, the kick continued during the whole schedule and intensified during the CFC, due to an increased reservoir influx rate from a reduced BHP. The fact that flow must be bled through the choke to keep the P_c constant, confirmed that a kick was in process. The BHP increased after the well was SI and caused the kick to stop. This is shown by a green marker on the BHP curve. The choke pressure also started to build up and stabilized at around 1800 psi, which was higher than for the SI response. This initial response, intended to simulate a manual MPD pump SD allowed a large additional kick volume of 42.3 bbls and consequently, was a poor response for this kick. Note that choke pressures were divided by ten before plotting for better resolution.

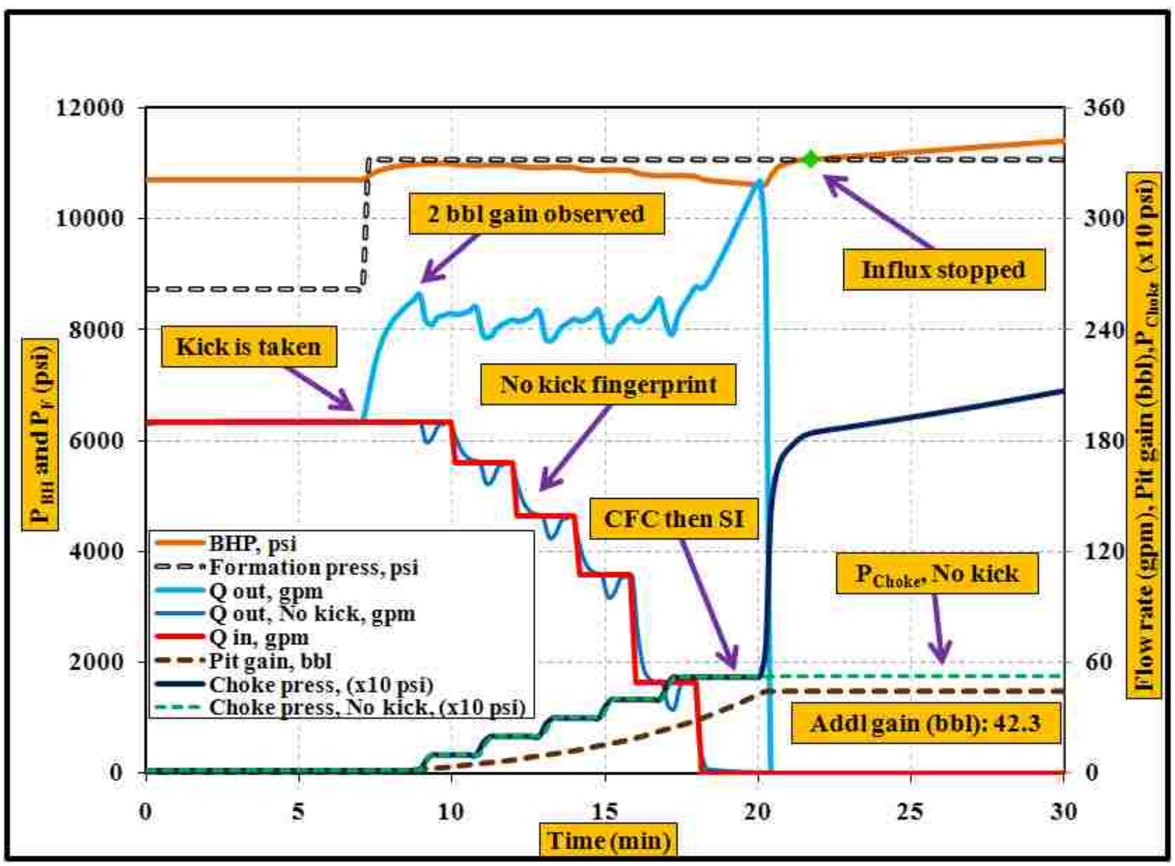


Fig. 5.2: Well X, MPD pump SD W/ CFC and SI on 2 bbl kick / high k / 0.5 ppge Circ UB

5.2.3 MPD Pump SD and SI

The MPD pump SD and SI response is exactly like the one explained under 5.2.2, except that the MPD pump SD schedule does not end in holding the P_c constant for a choked flow check. Instead, the choke will be closed after establishing the required P_c that balances the P_{AF} at the drilling rate. This action comes at the end of the MPD pump SD schedule, after stopping the mud pump. This response, which takes about 9.5 minutes until the well is SI, was consistently applied to all Well X kick scenarios. This schedule, like the previous one, simulates the manual application of the MPD pump SD. All general considerations of NCRs and those specific to MPD pump SD under 5.2 and 5.2.2 still apply.

5.2.3.1 Example of MPD Pump SD and SI

The application of this initial response was on the 2 bbl kick from Well X, corresponding to the same conditions as for the previous examples, as illustrated in Fig. 5.3.

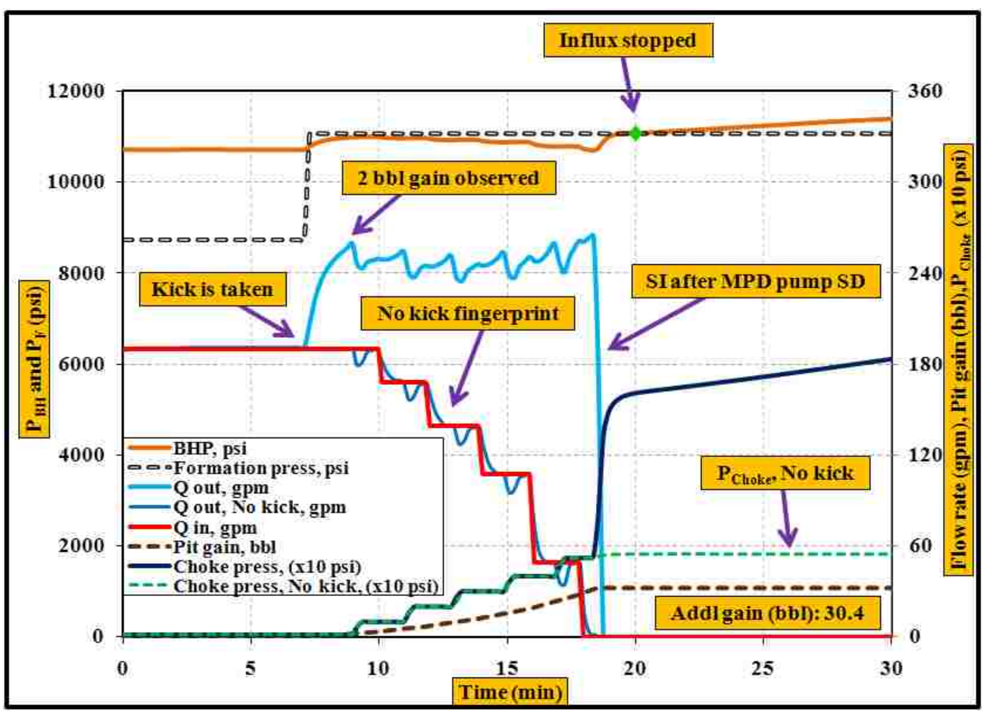


Fig. 5.3: Well X, MPD pump SD and SI on 2 bbl kick / high k / 0.5 ppge Circ UB

After confirmation of the 2 bbl kick, the MPD pump SD was applied. As soon as the required back pressure (520 psi) was achieved, the mud pump was shut down, and the choke was closed immediately. A no kick fingerprint is also shown, which indicates that an ongoing kick was sustained during the application of this response to the kick. Consequently, it allowed an additional gain of 30.4 bbls, which is less than the previous case. As a result, the choke pressure stabilized at around 1600 psi. These are due to the shorter duration of the response without a CFC.

A disadvantage is that the hard SI trapped some pressure in the well in the no kick case, which was not seen on the previous response with the CFC. Here, an increase of about 30 psi on the no kick choke pressure curve was observed. Choke pressures are divided by ten before plotting, for better resolution.

5.2.4 Auto MPD Pump SD W/ CFC and SI

If the drilling choke control on a well location is automated, then the MPD pump SD W/ CFC and SI that was explained under 5.2.2 can typically be more quickly applied. If a kick is confirmed, this response does not allow as much additional gain, as it is completed within 5.2 minutes as opposed to 11.5 minutes in the similar manual response. This schedule, shown in Table 5.3, was used in batch mode for simulation of all Well X kick scenarios for this response. All other considerations that were discussed for NCRs also remain true for this initial response.

Table 5.3: Schedule for Auto MPD pump SD W/ CFC and SI for Well X

Time (min)	Mud Flow in (gpm)	RCD	Choke	P_c (psi)	Comments
0.3	190	Closed	Open	100	MPD pump SD
0.3	168	Closed	Open	100	
0.3	168	Closed	Open	200	
0.3	139	Closed	Open	200	
0.3	139	Closed	Open	300	
0.3	107	Closed	Open	300	
0.3	107	Closed	Open	400	
0.3	49	Closed	Open	400	
0.3	49	Closed	Open	520	
2	0	Closed	Open	520	"choked flow check"
0.5	0	Closed	Closed	Buildup	SI
15	0	Closed	Closed	Buildup	SI, Monitor

5.2.4.1 Example of Auto MPD Pump SD W/ CFC and SI

Fig. 5.4 shows an application of a faster initial response, simulating an automated response, on the same Well X kick scenario. The schedule defined in Table 5.3 was applied, which included a MPD pump SD of approximately 3 minutes, followed by a 2 minute CFC and ending in SI. The well was flowing during the application of the response, especially during the CFC, in contrast to the no flow fingerprint. Since the duration of influx before SI was much less than previous MPD SD cases, an additional gain of only 16.9 bbls was taken. Shortly after the SI, the BHP increased past the formation pressure, and influx stopped, which the green marker points out. Stabilized choke pressure is around 1400 psi, which is less than its values in the previous MPD SD cases. Likewise, choke pressures are divided by ten before plotting in order for all curves and the legend to be seen clearly.

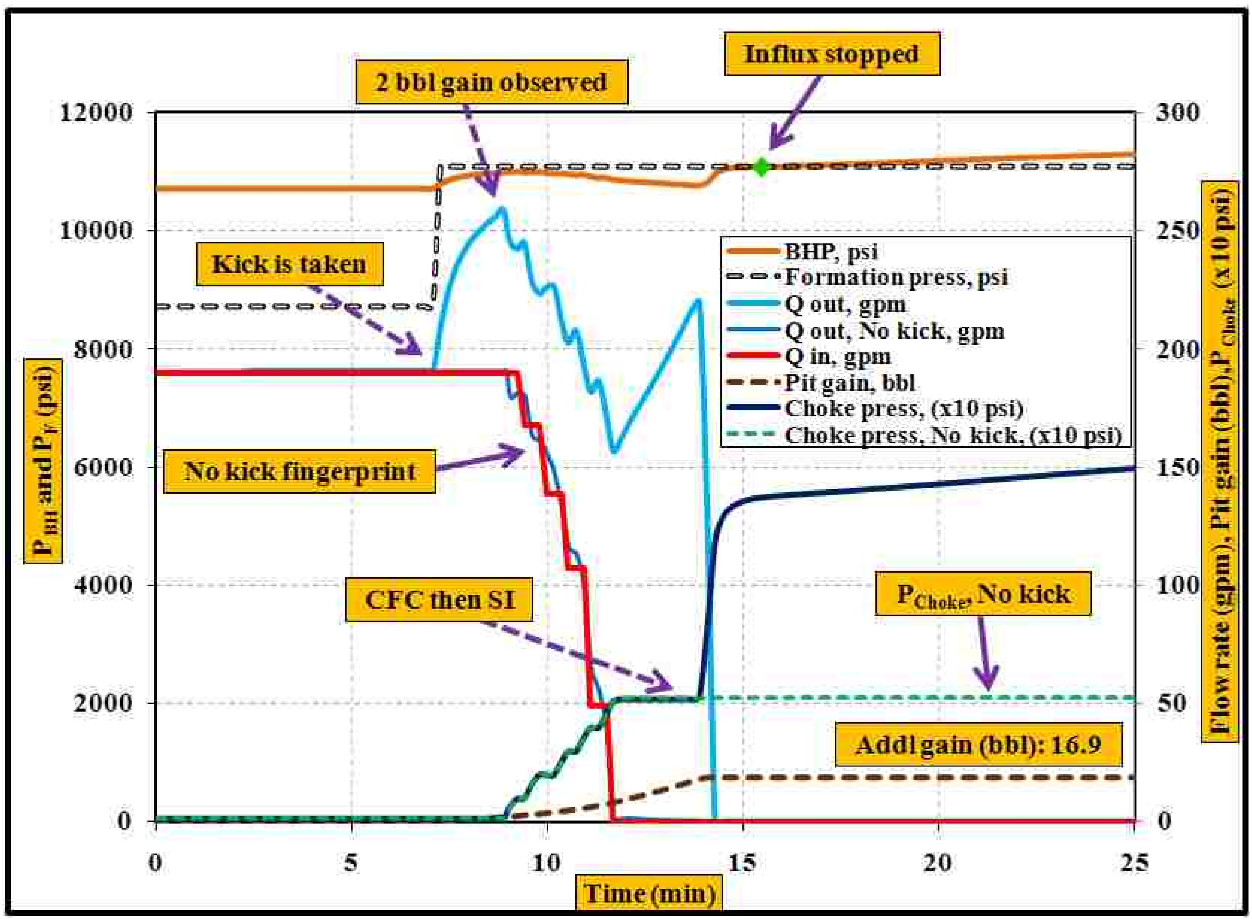


Fig. 5.4: Well X, Auto MPD pump SD W/ CFC& SI on 2 bbl kick/ high k/ 0.5 ppge Circ UB

5.2.5 Auto MPD Pump SD and SI

Auto MPD pump SD and SI is the last NCR that is studied. It is the same procedure as the manual MPD pump SD and SI discussed under 5.2.3, but it simulates a case where an automated drilling choke is available at the well site. This initial NCR is a faster response than the similar manual one. SI is reached in less than 3.5 minutes, as compared to 9.5 minutes in the MPD pump SD and SI. This schedule was consistently used in all Well X kick scenarios for this response. All other considerations discussed for NCRs also remain true for this initial response.

5.2.5.1 Example of Auto MPD Pump SD and SI

This NCR was also applied to the same Well X kick scenario. The result is plotted in Fig. 5.5. This automated MPD pump SD and SI does not include the CFC. After the initial 2 bbl kick, the automated MPD pump SD schedule was applied; beginning at about 8.5 minutes, and then, the drilling choke was closed at about 12 minutes.

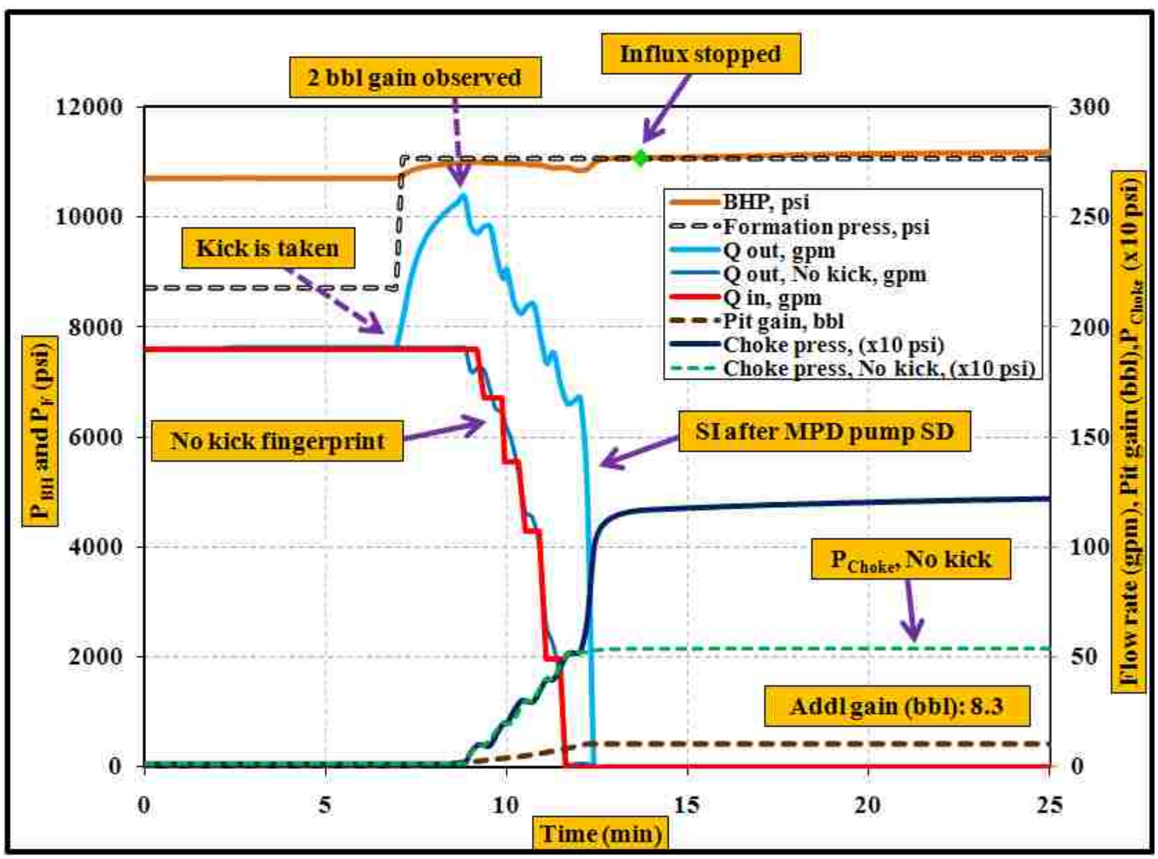


Fig. 5.5: Well X, Auto MPD pump SD and SI on 2 bbl kick / high k / 0.5 ppge Circ UB

The well was underbalanced during the MPD pump SD; however, its duration was the least among all MPD pump SD cases, and therefore the additional gain was minimized to only 8.3 bbls. Consequently, the choke pressure stabilized slightly less than 1200 psi, which is the least when compared to all other MPD pump SD cases for this specific kick scenario. Unfortunately, this auto MPD pump SD and SI case can trap excess pressure in the well. For the no kick case, the extra choke pressure was around 20 psi. Likewise, choke pressures were divided by ten and then plotted in order to not hide the view of other important curves or the legend.

5.3 Circulating Responses (CRs)

Four CRs studied in this research will be described in this section. During application of a CR to a kick scenario, mud circulation in the well is not stopped or interrupted, and hence, these are categorized as circulating responses. These responses generally aim to raise the BHP either by reducing the choke opening to increase casing pressure, or by increasing the pump rate to increase the ECD in the annulus.

One of the major benefits of applying the CRs to any kick scenario is their ability to minimize the NPT. Since mud circulation is never stopped, no mud pump start up procedure is required for kick circulation. Another benefit associated with application of CRs, is their ability to reduce the expected P_c, because the ECD increases the BHP relative to non-circulating conditions. Therefore they require less P_c to stop an influx as compared to NCRs.

Increased Q_{out} and the resulting pit gain are the major indicators that an influx is occurring. There are alternative ways to confirm that drilling into a high pressure permeable zone has taken place, such as a drilling break, data from a PWDT, drill pipe pressure etc, but these are not as directly indicative of a kick as an increased Q_{out} and the resulting pit gain. Additionally, CRs are generally intended to reduce the Q_{out} with the goal matching it with the mud flow rate in

(Q_{in}) as the criteria that formation flow has been stopped. Therefore, these responses require accurate Q_{out} metering to be effective.

If the volumetric rate of mud (incompressible fluid) going into the well and coming out of the well is equal, there should be no formation flow into the well. Therefore, the matching of flow rates, in and out, indicates that an influx has stopped. This method worked well for water kicks, but a serious complication in the case of gas kicks (compressible fluid) was that Q_{out} and Q_{in} could not always be matched.

Several attempts were made to address this inherent weakness in matching Q_{out} and Q_{in}. Finally, it was observed that the increasing rate of Q_{out} after a reduction due to a choke pressure increase decreases after every reduction and reached a minimum upon the formation flow was stopped. Subsequent choke pressure increases result in a repeatable, slower rate that reaches a slowly increasing rate just greater than Q_{in}. This minimal rate increase and repeatable trend of Q_{out} versus time following the kick stoppage was a consistent behavior. Consequently, it was used as a confirmation of the kick stoppage during the simulation of CRs in DFD and will be discussed in Chapter 6 (under 6.4). The other complication of the CRs is the less direct indication of the kick zone PP; study about this case is beyond the scope of this research. The CRs studied in this research include Stepwise P_c increase (Incr), Incr P_c to 80% of MAASP, Rapid P_c Incr, and Stepwise Q_{in} Incr.

5.3.1 Stepwise P_c Incr

The Stepwise P_c Incr response aims to simulate a manual application in which the mud pumping rate is held constant, but P_c is increased stepwise in response to an elevated Q_{out}. Several attempts showed that 100 psi steps on the choke were more effective than 50 psi steps and did not apply excessive BHP observed with 200 psi steps. In a MPD application, narrow drilling margins typically require careful P_c adjustments; hence, the step size should be chosen accordingly.

There was no fixed schedule for cases simulating this initial response; all simulations were conducted interactively. The simulations were based on accurate Q_{out} metering being available, but there was no fully automated or computer-aided choke control. In order to attain realism with this response as practiced manually in the real world, a consistent 30 second monitoring time was practiced after any P_c step which reduced Q_{out} to a new lower value. This provided enough time for the Q_{out} to be monitored in a dynamic system and compared with the Q_{in}. If there is no match, then the next P_c step would be taken. Application of P_c in steps was repeated until the increasing rate of Q_{out} versus time became minimal as a sign of the kick stoppage. This was further examined by application of the subsequent choke pressure increases to observe the repeatable Q_{out} trend. Then, similar to conventional well control, the resultant drill pipe pressure would be kept constant by choke adjustments to maintain BHP constant during kick circulation.

5.3.1.1 Example of Stepwise P_c Incr

Fig. 5.6 displays an application of the Stepwise P_c Incr response on the same Well X kick scenario that was discussed for the NCR examples (drilling at 190 gpm to the HP zone at 16265 ft MD). The BHP, formation, and drill pipe pressure were divided by 10 before plotting to allow use of one scale. Pressure was set for the choke input in DFD, and drilling stopped after an initial pit gain of 2 bbls. While keeping the same mud pump rate, a 100 psi choke pressure was applied, followed by a 30 second Q_{out} monitoring period, as explained earlier. Since this pressure was not sufficient to stop the influx, Q_{out} resumed its ascending trend. Therefore, another 100 psi choke pressure increase was applied, and this procedure continued until around 13 minutes of simulation time, when Q_{out} was reduced temporarily to less than Q_{in}. After this reduction, the increasing rate of Q_{out} versus time became minimal indicating that the influx was stopped, which also agrees with the influx stoppage time shown by the green marker on BHP data. This observation was confirmed by application of two arbitrarily selected 50 psi choke pressures increases, as annotated on the plot. Both the profile of Q_{out} versus time and the steady state Q_{out} rate were essentially the same after each of these confirmation increases as seen in Fig. 5.6 which indicates the repeatable Q_{out} trend was explained under section 5.3. An additional gain of 2.6 bbls was taken during the application of this response.

In a field application, a minimum choke pressure change, achievable with the rig equipment, would minimize the risk of applying an excessive pressure. The drill pipe pressure after halting the kick must be kept constant by choke adjustments to maintain a BHP constant during kick circulation, similar to the 'drillers' method. No choke adjustments were necessary because the drill pipe pressure did not change significantly after formation flow was stopped.

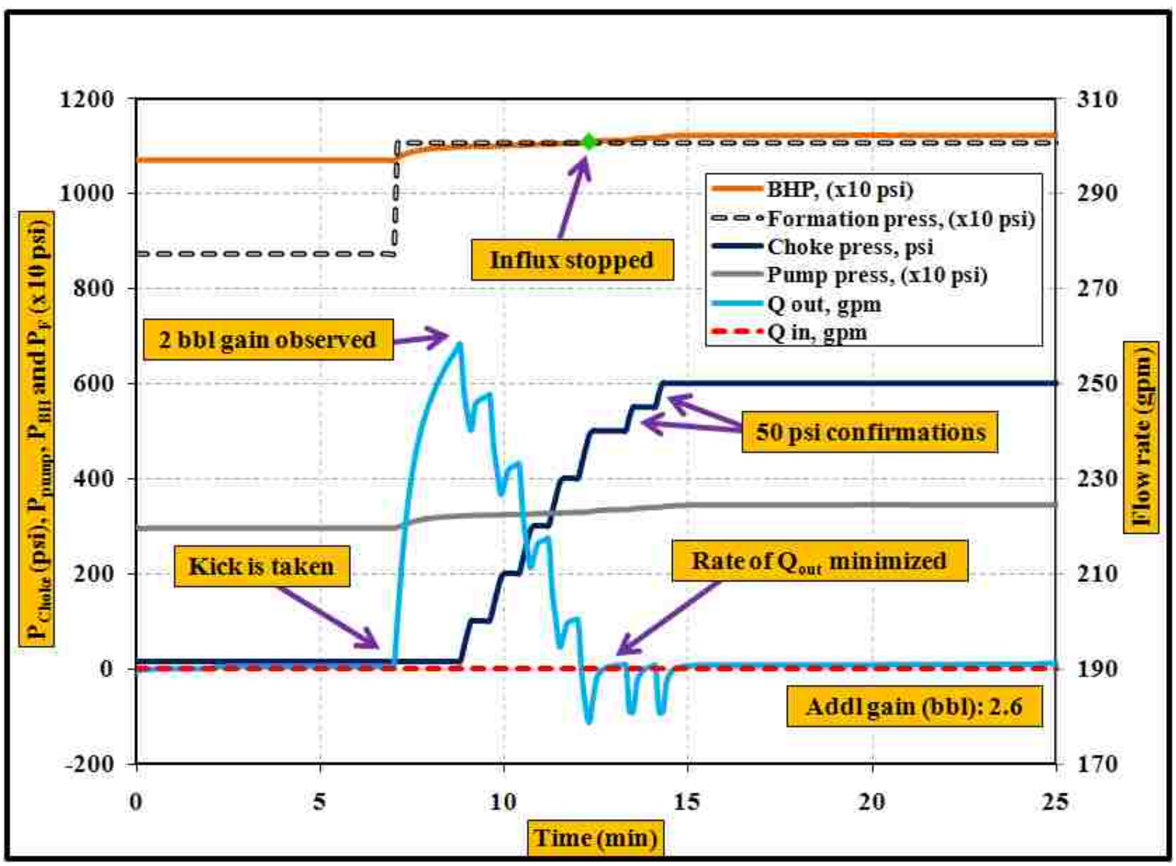


Fig. 5.6: Well X, Stepwise P_c Incr on 2 bbl kick / high k / 0.5 ppge Circ UB

5.3.2 Incr P_c to 80% of MAASP

The Incr P_c to 80% of MAASP response may be practiced manually or automated in the field. After a kick, the P_c is increased rapidly to the predefined maximum limit, 80% of MAASP, and then Q_{out} and pit gain are monitored. MAASP includes the maximum pressure ratings of the surface equipment, the casing, and the maximum pressure that can be applied without causing formation fracture below the casing shoe. Typically, the lowest value for maximum pressure is determined by fracture pressure. As explained in previous chapters, the casing shoe was considered to be the weak zone in the well. In that case, the MAASP is identical to another term, which is more distinctive. This term is MACPBFF (maximum allowable casing pressure before formation fracture) and 80% of this value is used for this response to provide a safety margin. These maximum limits are usually known after drilling out the shoe, and they are known for Well X and Well Z (Table 4.2 for Well X and Table 4.5 for Well Z).

5.3.2.1 Example of Incr Pc to 80% of MAASP

Fig. 5.7 shows an example application of the Incr P_c to 80% of MAASP response on the same Well X kick scenario. After observing a 2 bbl kick and keeping the same mud pump rate, 670 psi was applied to the choke. This value is about 80% of the MAASP for Well X. This pressure was held constant while the Q_{out} was monitored. The established choke pressure for this kick scenario reduced the Q_{out} temporarily to less than Q_{in}. Finally, it became approximately equal to the Q_{out} steady state rate, which confirmed that the influx stopped. This is also shown by the green marker on the BHP curve.

This response stopped the influx rapidly, resulting in only 1 bbl of additional gain. However, the Circ UB for this case is small relative to the choke pressure of 670 psi. This pressure was so excessive that large increases on the BHP and drill pipe curves can be seen that were not experienced in previous cases. The drill pipe pressure did not drop noticeably during the period shown, and therefore no choke adjustments were necessary. The same procedure was repeated for all Well X and Z simulations.

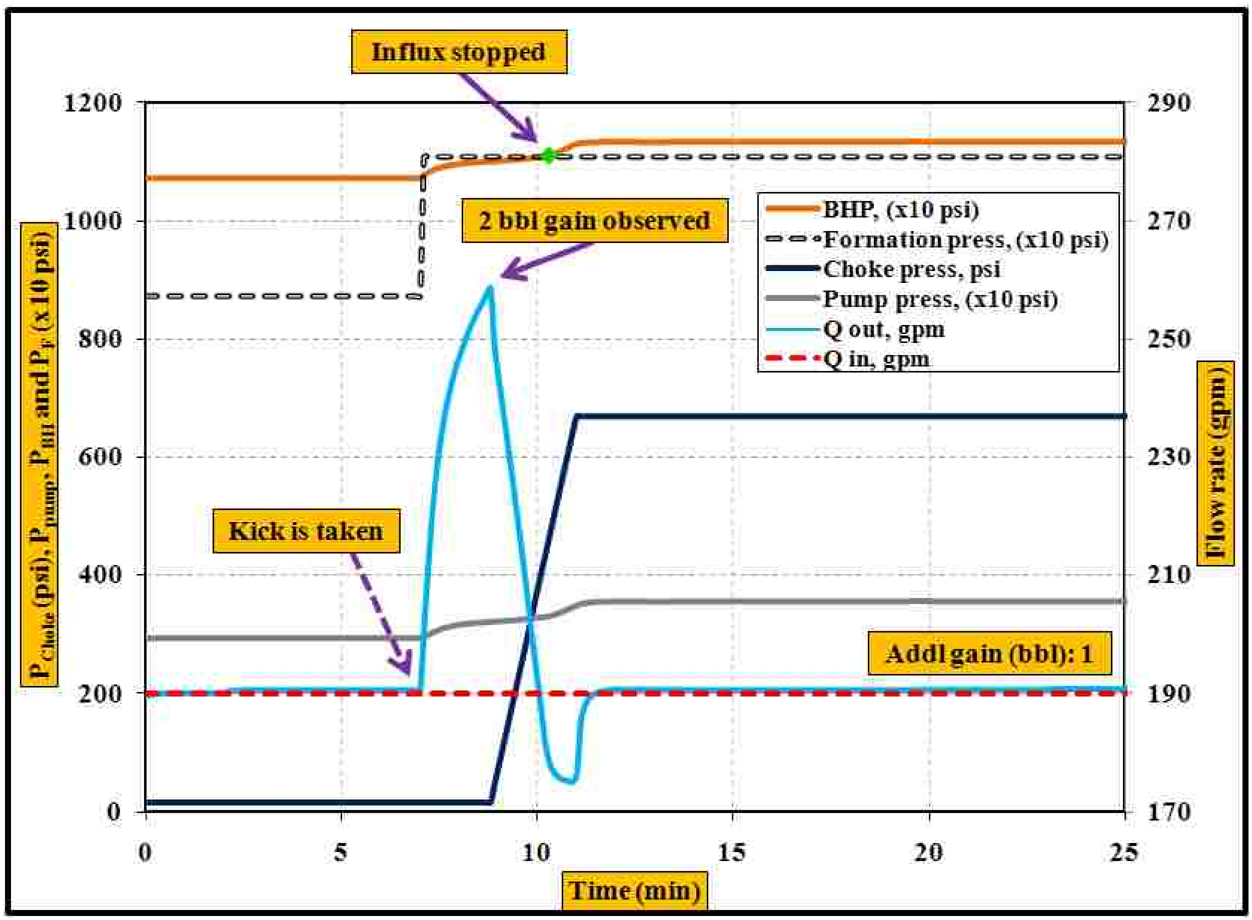


Fig. 5.7: Well X, Incr P_c to 80% of MAASP on 2 bbl kick / high k / 0.5 ppge Circ UB

5.3.3 Rapid P_c Incr

The Rapid P_c Incr response was initially suggested by a LSU MPD consortium industry member. The specific approach used herein was developed in the course of this research. Accurate Q_{out} metering is required for this response to be applied in the field. An automated drilling choke is also generally used. The idea was to keep the Q_{in} at the drilling rate while rapidly reducing the choke opening, until Q_{out} dropped to around 110% of Q_{in}, and then to proceed with much smaller choke adjustments in order to match Q_{out} and Q_{in}, as a sign of t kick stoppage.

To simulate such a response in DFD, choke closing must be performed interactively at a time step, while monitoring Q_{out}. If the Q_{out} is approaching the Q_{in}, smaller choke adjustments must be taken. These choke closing steps should be defined in a manner generally applicable for any well conditions. Doing so for all Well X and Z kick scenarios, proved to be challenging. A maximum time step of 0.1 minute (or 6 seconds) was selected as a quick enough step within which any choke adjustments or Q_{out} monitoring could be implemented appropriately in order to simulate a rapid P_c response.

A choke closing rate of 0.07 (1 stands for fully open choke) per time step was decided to be used at the beginning of the response. If the Q_{out} reaches 110% of Q_{in}, then the choke closing rate was reduced to 0.02 to 0.03 per longer time step, in order to to allow more precise Q_{out} monitoring before confirming that the influx has stopped. After several simulations, it was noticed that although this schedule could function to stop different kicks, it needed modification for a different well scenario. It was slow for Well X, as it would take some time to establish a significant P_c. Moreover in several simulations with low rate kicks (low k), Q_{out} either was already below or dropped quickly below 105 % of Q_{in}, yet formation influx still occurred. A key question was what would be the next choke closing step, knowing that the previous one resulted in more than a 5% drop in Q_{out}?

Several simulations were made to evaluate the last issue while trying to define a robust schedule with general applicability. It was noticed that a fixed schedule would not work for all the kick scenarios. The reduction in Q_{out} increases for a given reduction in choke opening as the choke size gets smaller. Therefore, monitoring the reduction of the Q_{out} progressively versus the choke closing rate allows finding a choke closing rate that would achieve the Q_{out} reduction required to match with the Q_{in}. Consequently, it was found that using fixed choke closing rates of either 0.02 or 0.03 after Q_{out} was less than 110 % of Q_{in} was not effective. These fixed step sizes could give resulting pressure changes that were either too small or too large depending on well conditions. Hence, for each kick scenario, an attempt was made to determine the proper choke closing rate from the actual Q_{out} reductions.

A revised procedure started with a fully open choke and proceeded with a 0.07 choke closing rate per 6 second time step, while monitoring the Q_{out} reductions. If a prior choke size reduction did not drop the Q_{out} to less than 110% of Q_{in}, it would be repeated. Once this criterion was met, the choke closing rate was adjusted using a linear proportional logic. This simple calculation is based on the Q_{out} reduction achieved by means of the previous choke size reduction. This process would find a choke size reduction that proportionally would reduce the current Q_{out} to the Q_{in}. In order to have a more conclusive reduction in Q_{out}, for the proper choke closing rate calculation, it was decided to target the Q_{out} reduction to 95% of Q_{in}. Not only did this step allow monitoring the increasing rate of Q_{out} as it approached the Q_{in} for the kick stoppage identification, but it also provided a margin for further choke closing adjustments, should the prior reduction in Q_{out} be insufficient. If Q_{out} still does not match the Q_{in}, much smaller choke size reductions of 0.005 to 0.01 per 3 to 5 time steps could be continued until the flow stoppage criterion was met. Since this modification proved to rapidly reduce the Q_{out}, it allowed a faster BHP build up and stopped the influx more efficiently, compared to previous simulations.

Ultimately, this method was further developed, understanding the that this response would be faster if a partially closed choke was selected initially. A simple practice can be repeated at well site just after drilling a casing shoe or when the risk of complications is judged to be minimal. A choke opening that provides 50 to 100 psi of P_c may be found quickly by trial-and-error. Later, this choke opening can be directly implemented as the first step in the method explained above. This eliminates the slow response experienced on the earlier implementation of this response to Well X cases. These choke openings were 50% and 80%, respectively, for Wells X and Z. After these modifications, further simulations suggested that the process could start with a 0.05 choke size reduction per 6 second time step rate for all the kick scenarios of both wells after the initial choke size was reached.

Table 5.4 is a schedule that demonstrates the procedure employed to simulate the Rapid P_c Incr response in DFD for Well X kick scenarios. The initial choke opening is 50%. This schedule runs with 0.05 choke opening reductions per 6 second, unless the ΔQ_{to_target} is less than $\Delta Q_{achieved}$. This simply means that Q_{out} is in the proximity of Q_{in} and a smaller increment of choke closing than 0.05 should be used. The new choke closing rate can be calculated as:

$$X = \frac{(0.05)*(\Delta Q_{to\_target})}{(\Delta Q_n)*\left(\frac{\Delta Q_n}{\Delta Q_{n-1}}\right)} \quad \ldots\ldots \text{(Eq. 5.1, where } \Delta Q_n > \Delta Q_{n-1}\text{)}$$

Table 5.4: An example schedule for Rapid P_c Incr response

n	$(Q_{out})_{old}$	Choke Opening	$(Q_{out})_{new}$	$\Delta Q_{achieved}$	$(Q_{out})_{6sec\_monitor}$	ΔQ_{to_target}
1	Q1	0.5	Q2	ΔQ1 = Q1-Q2	Q3	Q3-0.95Q_{in}
2	Q3	0.45	Q4	ΔQ2 = Q3-Q4	Q5	Q5-0.95Q_{in}
3	Q5	0.4	Q6	ΔQ3 = Q5-Q6	Q7	Q7-0.95Q_{in}
4	Q7	?	?	?	?	?

The $\Delta Q_{achieved}$ is not in reality a linear function of choke closing steps. If the choke opening is reduced in 0.05 steps as shown in the table above, then the $\Delta Q_{achieved}$ continues to increase. Therefore for simplicity, the $\Delta Q_{achieved}$ used in Eq. 5.1 is pro-rated based on what is achieved in the previous step. Several adaptations to the original idea were necessary to determine a general procedure for the Rapid P_c Incr response in DFD. The final procedure, applied to Well X and Z kick scenarios, can be summarized as follows:

1. Find the equivalent choke opening at the regular circulating rate that provides a P_c of 50 to 100 psi.

2. After taking a kick, reduce the choke opening continuously until reaching the value found in step 1.

3. Continue closing the choke opening at the rate of 0.5/minute (0.05/time step) while monitoring the Q_{out} reduction ($\Delta Q_{achieved}$) as in Table 5.4.

4. Use smaller increments when the Q_{out} reduction exceeds the Q_{out} to 95% Q_{in} margin (ΔQ_{to_target}) per Eq. 5.1.

5. If kick stoppage is not yet confirmed, use smaller increments of 0.005 to 0.01/3 to 5 time steps and monitor Q_{out} for a minimal increasing rate change.

5.3.3.1 Example of Rapid P_c Incr

Fig. 5.8 presents an application of Rapid P_c Incr response on the same Well X kick scenario as for the other responses. Choke input was set to opening in DFD input parameters. After the initial pit gain confirmation of 2 bbls, and while keeping the same mud pump rate, the procedure above was applied to reach the P_c in order to rapidly stop formation flow. Table 5.5 is the implementation of the procedure explained by Table 5.4 for the simulation of this particular Well X kick scenario. A choke opening of 50% was selected as the beginning step for all the Well X scenarios. The equivalent initial choke opening for Well Z cases was 80%.

Q_{out} was monitored progressively before and after each 5% choke opening reduction, in order to see the achieved Q_{out} reduction ($\Delta Q_{achieved}$). These values were constantly compared to the pre-assumed target of the Q_{out}, which was 95% of Q_{in} (180 gpm). When the $\Delta Q_{achieved}$ exceeded the requirement of reaching the target Q_{out} value (i.e., more than ΔQ_{to_target}), a smaller choke closing rate was applied. These values are highlighted in red in Table 5.5. The new value for the choke closing rate was calculated as per Eq. 5.1:

$$X = \frac{(5)*(19)}{(35)*(35/23)} = 2\%$$

Table 5.5: Implemented choke schedule for the kick scenario in Fig. 5.8

$(Q_{out})_{old}$	Choke Opening (%)	$(Q_{out})_{new}$	$\Delta Q_{achieved}$	$(Q_{out})_{6sec\_monitor}$	ΔQ_{to_target}
258	50	253	5	256	76
256	45	252	4	254	74
254	40	246	8	250	70
250	35	237	13	242	62
242	30	219	23	226	46
226	25	191	**35**	199	**19 (< 35)**
199	23	183	16	190	**Influx stopped**

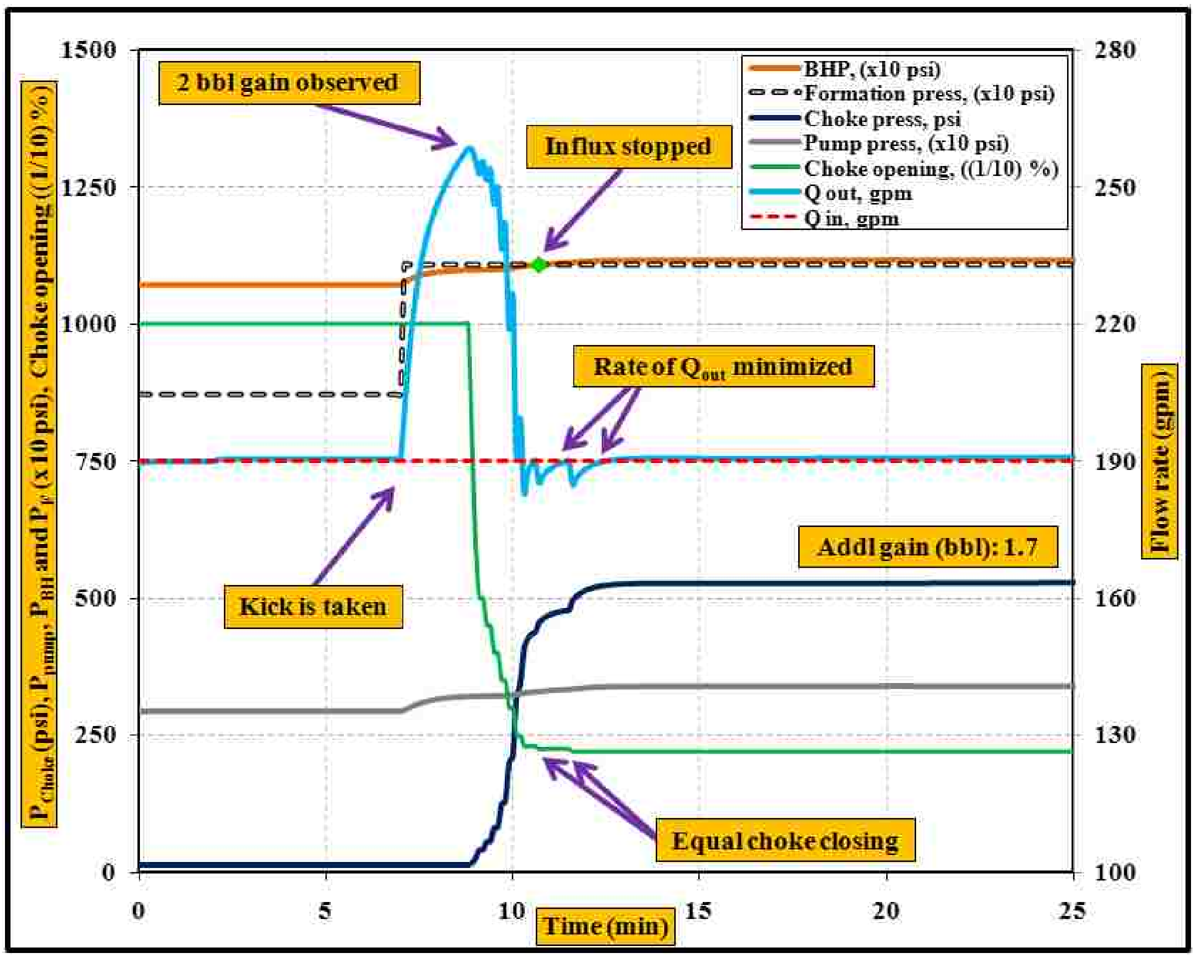


Fig. 5.8: Well X, Rapid P_c Incr on 2 bbl kick / high k / 0.5 ppge Circ UB

The rate of Q_{out} changed as soon as the each choke adjustment was made, until Q_{out} dropped below Q_{in}. This was an indication that the influx might be stopped, as in the Stepwise P_c Incr method. To confirm this, two further choke manipulations were taken as shown on the choke opening curve. The Q_{out} profile versus time was repeated almost identically after the application of these choke closing rates. This satisfied the flow stoppage criterion described in section 5.3 and confirmed that no more influx was occurring from the reservoir into the well. The green marker on the BHP curve shows when the influx stopped. This response took around 2 minutes of simulation time to complete and allowed only 1.7 bbls additional gain. The drill pipe pressure and consequently the BHP were almost constant once formation flow was stopped, so no more choke adjustments were necessary. The same procedure was applied to the rest of Well X kick and all of the Well Z kick scenarios.

5.3.4 Stepwise Q_{in} Incr

The Stepwise Q_{in} Incr response, which also requires accurate Q_{out} metering for its application, uses increased Q_{in} to increase ECD in the annulus to stop an influx. P_c remains the same with no choke adjustments made until the influx is stopped. Then, the established drill pipe pressure and pump rate must be kept constant for kick circulation. Q_{in} can be increased in steps of 10 to 20 gpm per time step (6 -12 seconds) depending on the quantity of the initial Q_{out}. If there is significant friction in the annulus, the Q_{in} should approach the Q_{out}. Q_{out} equal to Q_{in} is used as an indication that the influx has stopped.

5.3.4.1 Example of Stepwise Q_{in} Incr

Fig. 5.9 shows an application of Stepwise Q_{in} Incr response on the same Well X kick scenario. After the initial gain of 2 bbls while keeping the same choke pressure (15 psi), Q_{in} was increased stepwise in response to Q_{out} as explained above. In a slim wellbore like Well X, the clearance between the open hole and the BHA is small, therefore a large P_{AF} can be achieved simply by increasing the mud flow rate. In this simulation, Q_{in} was increased 10 gpm per step at the beginning, and while approaching the Q_{out}, a smaller increment of 5 gpm was taken. As annotated on the plot, when Q_{in} surpassed Q_{out} after applying a 5 gpm mud flow rate increase, the influx was stopped. At this time, two 5 gpm identical flow rate increments were applied, similar to applying choke pressure increases in the other circulating responses, to assure that the kick is stopped and to acquire some BHP margin. This response successfully stopped the influx and allowed only 2.4 bbls additional gain during its application.

The drill pipe pressure of 5960 psi, established during the initial response, did not drop much during the period shown, but it would have if the monitoring had continued for a few minutes more. Due to the fact that gas expansion in the annulus was accelerated by the elevated Q_{in} (over 300 gpm), the loss of hydrostatic pressure in the annulus was rapid for this response, and consequently, the BHP kept falling. A second kick would result if the choke pressure was not increased to keep the drill pipe pressure constant during kick circulation.

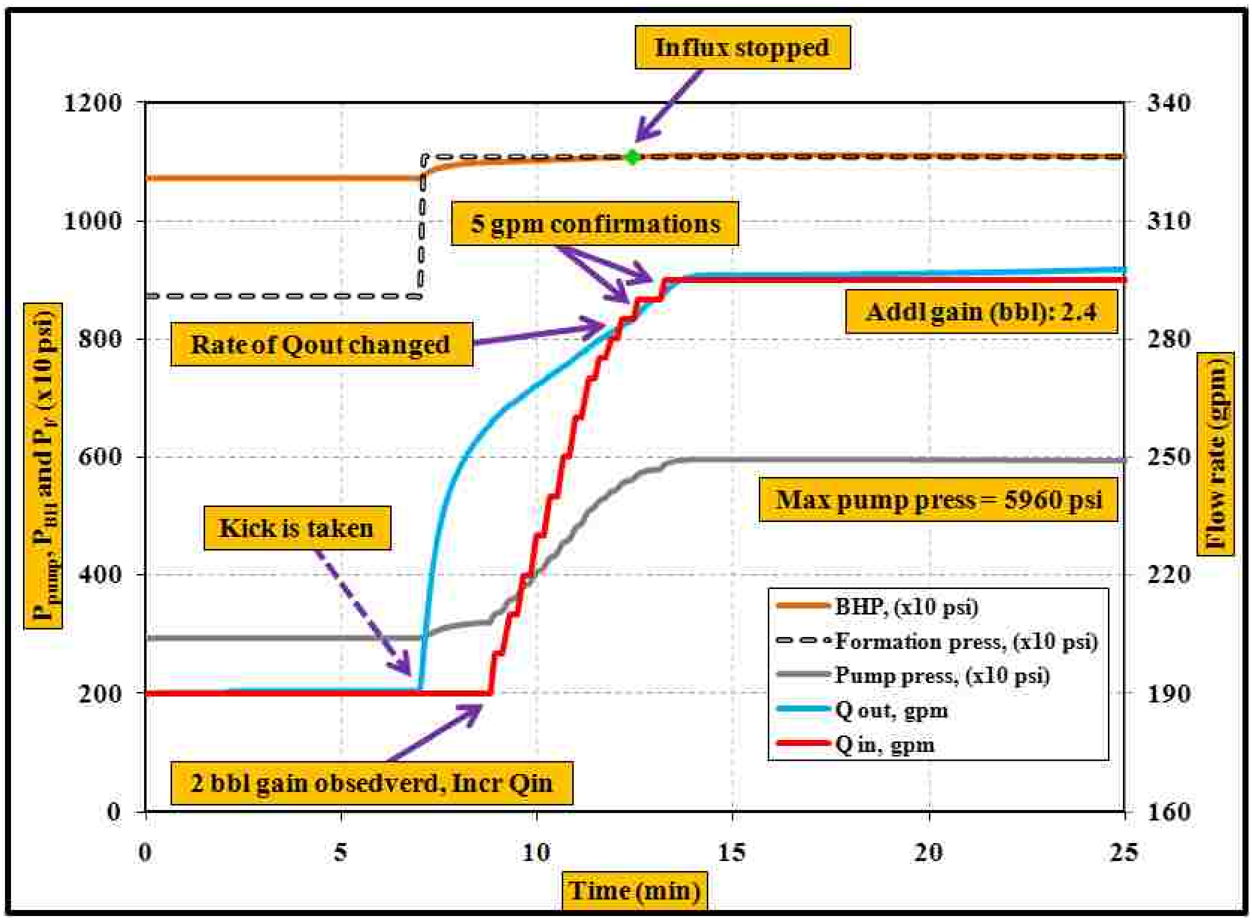


Fig. 5.9: Well X, Stepwise Q_{in} Incr on 2 bbl kick / high k / 0.5 ppge Circ UB

6. DATA ANALYSIS

6.1 Introduction

The non-circulation and circulating initial responses (NCRs and CRs), defined in the previous chapter were applied to all Well X and Well Z kick scenarios. The results of these simulations are discussed in this chapter. Specifically, these include a validation summary for DFD choke input options, a summary of simulation results, the method for determining kick stoppage during CRs, the identification of the best initial responses based on the evaluation criteria introduced in Chapter 3, and an initial response plan based on the best identified responses.

6.2 DFD Inputs for Choke Operation

DFD has two options for the choke input. Pressure values may be input directly during simulations to increase or decrease the choke pressure. Alternatively, choke openings can be selected from 0 to 1. Since the NCRs required the choke to be closed fully, the pressure input option was not helpful. However, it was much easier to select the choke pressure input for some of the CRs, such as Stepwise P_c Incr or Incr P_c to 80% of MAASP. In order to determine the best initial responses, the simulation results from application of the initial responses to different kicks are compared. Therefore, it seemed necessary to evaluate the simulation results to make certain that they were independent of the DFD choke input options.

Fig. 6.1 shows the simulation result of Incr P_c to 80% of the MAASP response to a 2 bbl kick from the Well X HP sand with high permeability and a circulating (Circ) UB of 0.1 ppge. Although this response was performed throughout this research using the choke pressure input, it was also tried using the choke opening input on this plot. Several choke adjustments, as seen, were required before the target pressure could be achieved (670 psi), which took slightly longer than the DFD through the use of a fixed pressure change rate of 5 psi/ (unit time), available with the choke pressure input option.

It was experienced after several simulations that the target pressure could not be possibly be achieved fast enough by the operator's manual manipulation of the choke opening compared to the pressure achieved by DFD when the choke pressure was used as an input. Also, the operator involvement needed when using choke opening made consistency difficult. Ultimately, it was concluded to use the pressure input for the choke in DFD for those respective initial responses that require pressure input to ease simulation to make the results more repeatable. Table 6.1 summarizes the results of the simulations shown in Fig. 6.1. There is no practical difference between BHP, pressure at shoe, and drill pipe pressure data. The difference in the gains between choke input options is solely due to the difficulty of adjusting the pressure manually using the choke opening.

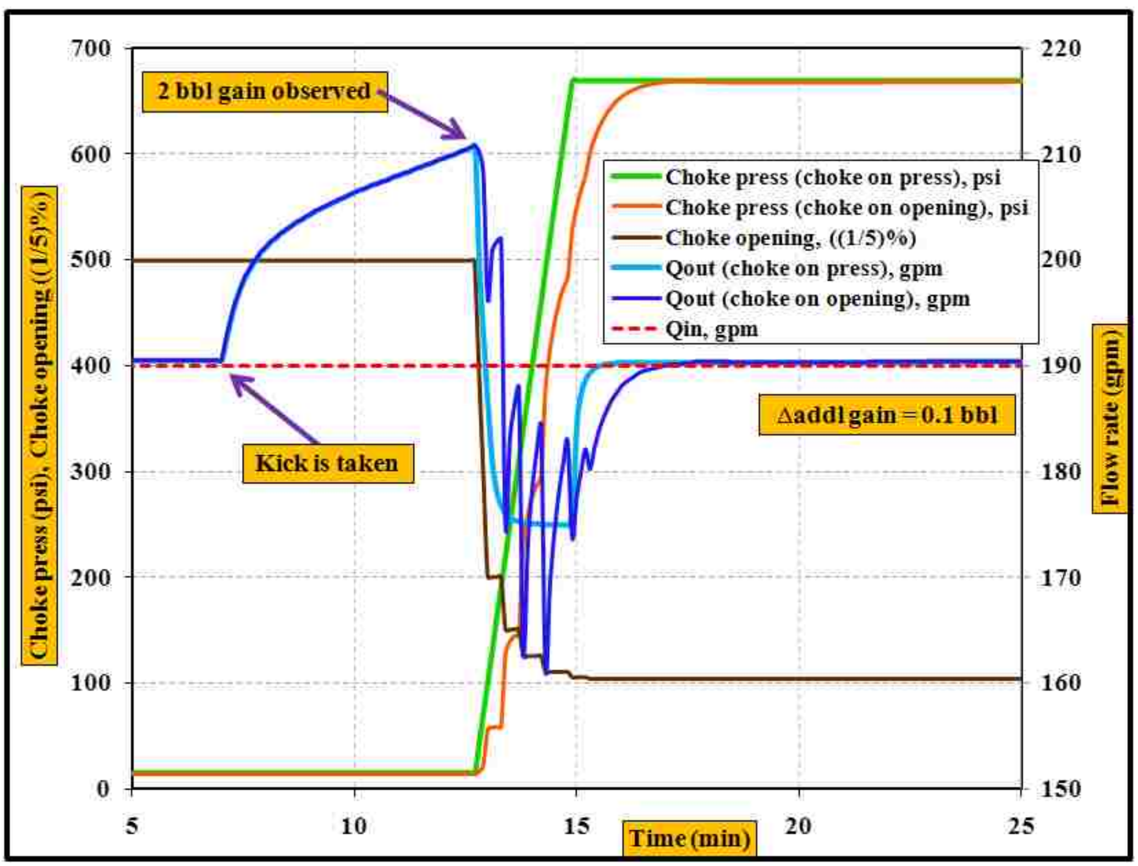


Fig. 6.1: Comparison of choke input selection on a 2 bbl kick / high k / 0.1 ppge Circ UB

Table 6.1: Comparison of DFD choke inputs on a 2 bbl kick from Well X

	BHP (psi)	Shoe press (psi)	$P_{drill\ pipe}$ (psi)	total gain (bbl)
Choke input on pressure	**10785**	**10086**	**3018**	**2.00**
Choke input on opening	**10790**	**10090**	**3020**	**2.10**
Difference (%)	**0.05**	**0.04**	**0.07**	**5**

6.3 Simulation Results

Appendix C presents the results of the simulations in two parts. In the first part, the results of the application of the non-circulating responses (five NCRs) and the circulating responses (four CRs) are tabulated versus different kick scenarios and well geometries. Since the entire simulation output data could not be tabulated, the most important results are shown including a) choke pressure when the kick stopped and its value after 10 minutes, b) pressure at shoe when the kick stopped and its value after 10 minutes, c) BHP at 10 minutes after kick stoppage and additional gain from kick detection until its stoppage. The 10 minutes monitoring time was chosen as a rule of thumb, because, not only is it important to know the simulation outputs at the kick stoppage, but also to know and compare what occurs shortly thereafter. Twelve kick scenarios are coded, based on each set of initial responses (NCR or CR) and well geometries (2). Consequently, 48 cases were recognized (C1 to C48, where C refers to Appendix C). An index of these tables is found in Appendix C, where the tables of results and simulation plots of Well X and Z are shown. Further limitations or inapplicability of a response are addressed in the tables.

In the second part of Appendix C, the results of the simulations are plotted. Each page presents a case with the same code given for the corresponding tables. Flow rates and choke pressures are plotted versus time. Moreover, additional gains and any other significant results are annotated on the plots. Since the NCRs reduce to SI for Well Z, it became possible to plot all of the twelve kick scenarios on two single pages. For the manual and automated MPD pump SD responses, the no-kick fingerprints are also plotted to see what the responses would look like in absence of the kick. For each successful circulating response, kick stoppage time was retrieved from the BHP data. The corresponding time was marked by an arrow in the same color of the respective curve. There might be some minor differences between these marks and the kick stoppage times interpreted from the Q_{out} trend change during implementation of the simulations.

It should be noted that the simulation outputs of the NCRs, such as choke pressure and BHP are independent of operator manipulation once the pumps are stopped and well is closed in. For the CRs however, the procedure employed for each response can impact the outputs. Consequently, as opposed to the NCRs the simulation results of the CRs are inherently more operator and procedure dependent. This is the reason why the simulation outputs, such as choke pressure and pressure at the shoe, might be less consistent among the CRs.

6.4 Determining whether Kick Influx Stopped for Circulating Responses

The presumed basis for determining that an influx has been stopped by a circulating response is that flow out, Q_{out}, is equal to flow in, Q_{in}. This method to confirm the stoppage of a kick and of formation flow into the well, pertained only to the application of the CRs. It is unnecessary for the NCRs, since the influx surely stopped if an intact well was closed-in. In both categories of the CRs, either increasing the choke pressure at the same pumping rate or increasing the ECD with a fully open choke, the basic concept of matching Q_{out} to Q_{in} as a sign that the influx stopped proved to be effective for intact wells in a previous study[91]. Simulation of water kicks in this study showed that the influx from the HP zone did stop as the Q_{out} was matched with Q_{in} (Fig. 6.2). Consequently, it became the primary approach in all of the circulating response simulations because it confirmed that a kick was stopped.

During larger gas kicks however, simulations showed that the Q_{out} could not be forced to match the Q_{in} exactly, even after the influx was stopped, or even by applying a much higher choke pressure than was required to stop the flow. This was due to gas expansion occurring in the annulus that would push the mud out of the well thus causing the Q_{out} to increase, as exemplified and explained in a previous report[101]. Consequently, flow matching does not provide a reliable means to determine whether a gas influx has been stopped, at least for a large influx into a water base mud.

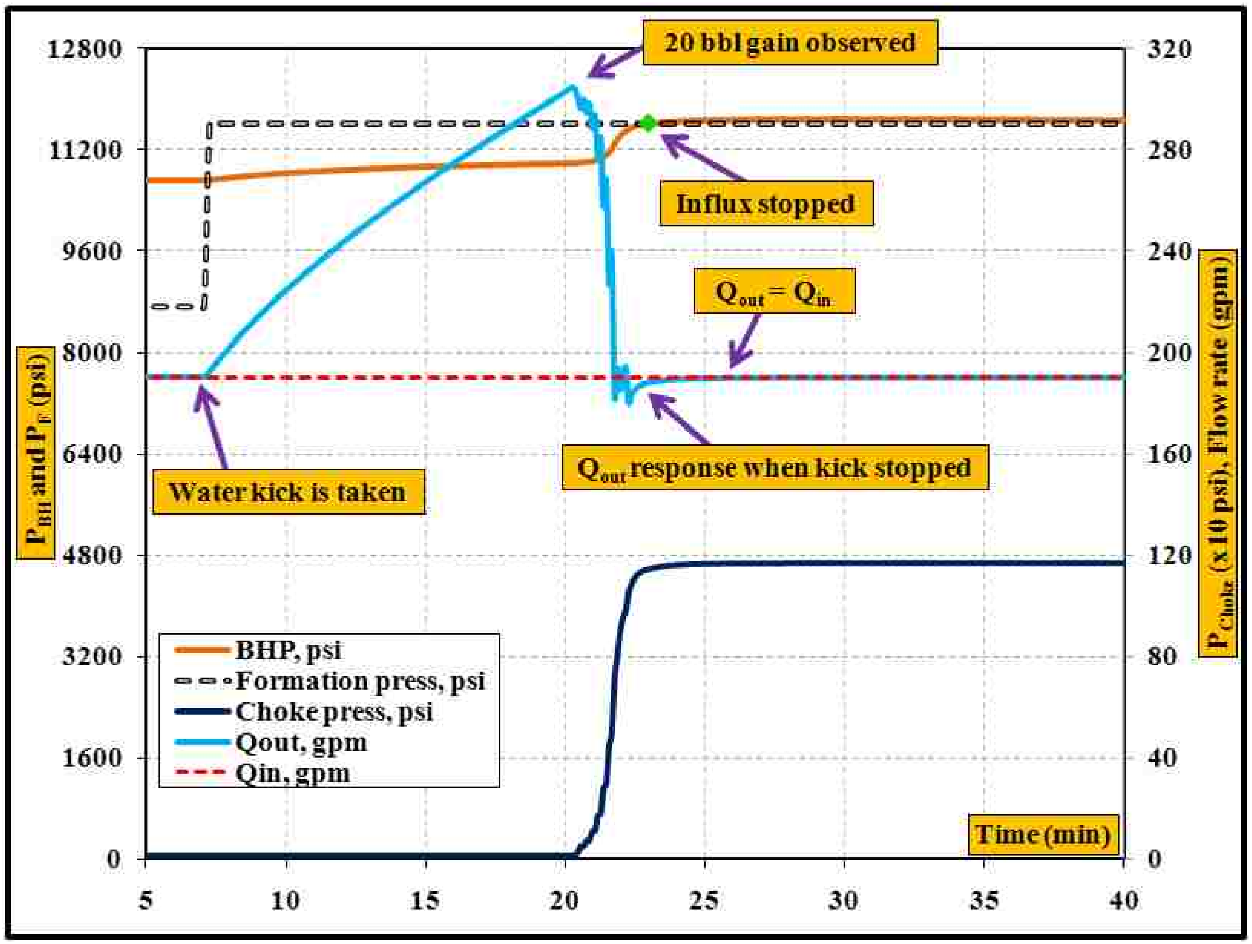


Fig. 6.2: 20 bbl water kick in Well X (high k, 1.2 ppge Circ UB)

6.4.1 Flow out Behavior during Circulating Responses to Gas Kicks

Drilling is typically stopped immediately after a kick is identified to make an initial response to stop the kick. A commonly proposed MPD response would be to reduce the size of the choke opening. An example response is the Rapid P_c Incr method. Fig. 6.3 shows a simplified illustration of this response to an ongoing gas kick during a typical MPD operation, after drilling into a zone with a higher PP than expected. If the well is intact, this elevated choke pressure will compress the fluid in the annulus and increase the BHP. Therefore, the drawdown at the kick zone will be reduced. This results in a reduced influx rate from the reservoir (predicted by reservoir inflow performance equation, Eq. 6.1 in the next section). Consequently, a reduction in the surface Q_{out} will be observed (Eq. 6.2 in the next section). Further choking of the mud flow increases the BHP and reduces the Q_{out} progressively until a ΔP_{Choke} is achieved that causes the drawdown to reduce to zero, i.e., the BHP will be equal to the HP zone PP, and thus the influx stops.

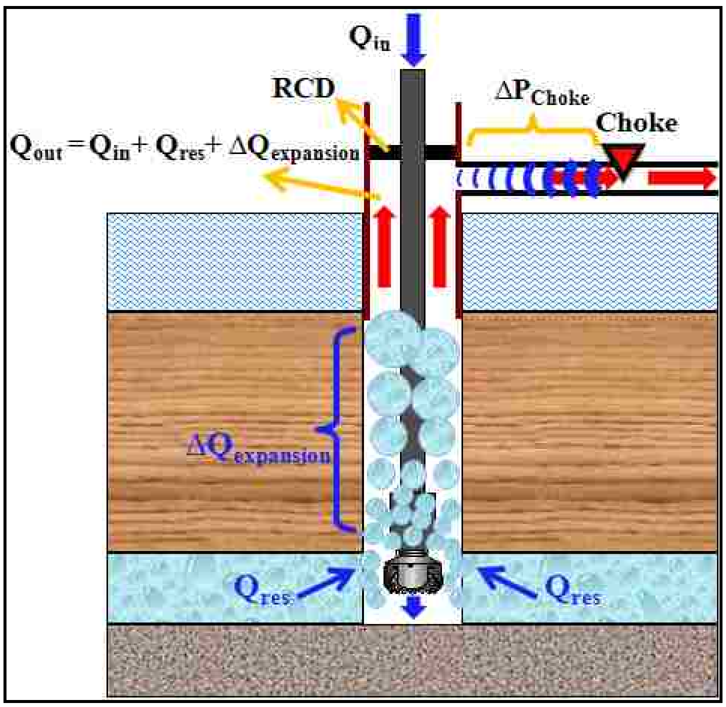


Fig. 6.3: Qualitative illustration of increasing choke pressure at constant pumping rate

Fig. 6.4 is a provisional simulation of a gas kick in Well X, where the flow of mud was sequentially choked to examine flow rate Q_{out} behavior after the kick stopped. Note that after influx stopped, the Q_{out} increased much slower than previous choke size reductions. It is also notable that this was true for the water kicks shown in Fig. 6.2. More importantly, this flow out transient behavior was then repeatable, following subsequent choke size reductions. This behavior provides a logical basis for determining stoppage of an influx more conclusively than simply comparing Q_{out} to Q_{in}.

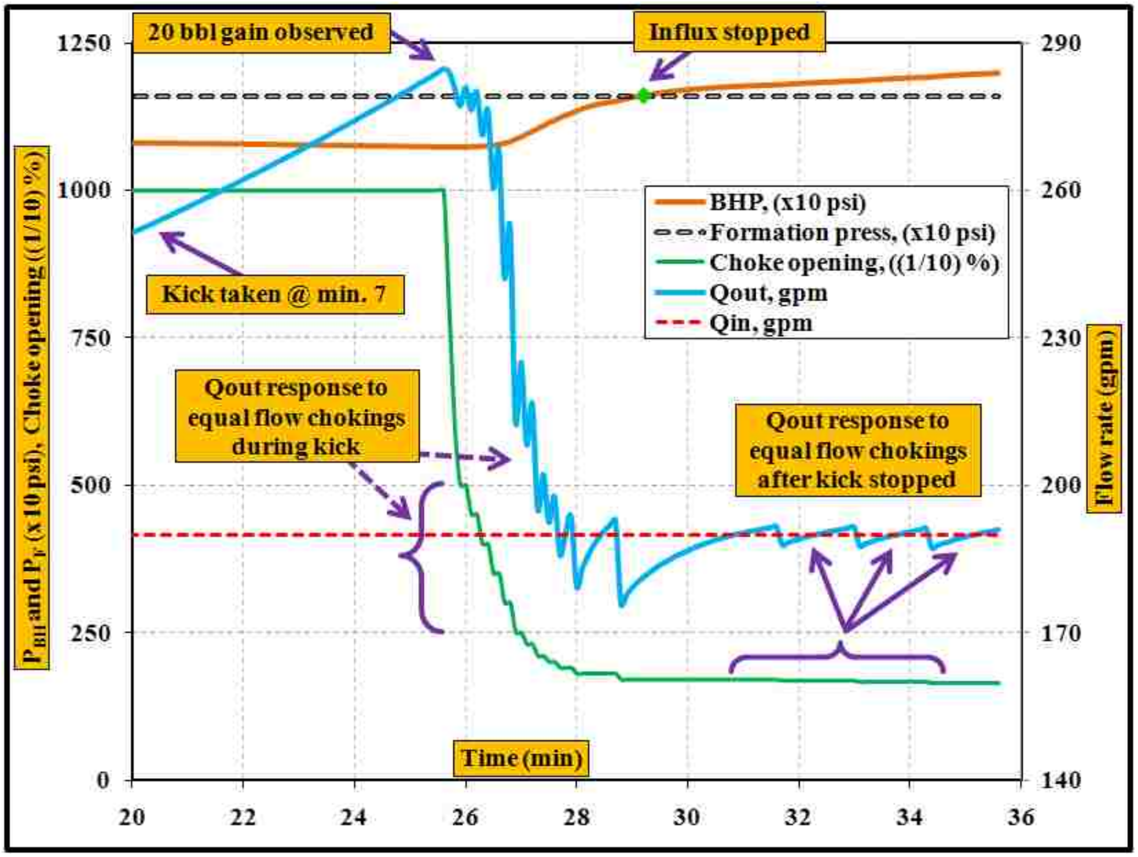


Fig. 6.4: A minimized Q_{out} Incr rate and repeatable trend versus time after influx stopped

6.4.1.1 Explanation

The influx rate from a gas reservoir (Q_{res}) is a complicated function. Equation 6.1 is a typical radial gas inflow equation[102] consisting of a Darcy and a non-Darcy term. A key element which controls the influx rate in any inflow equation is the drawdown between the average formation PP and the BHP. This means that if the BHP can be increased enough by the application of an initial response, then the influx rate can be reduced to zero. The coefficient A and B in this form of inflow equation represent a function of reservoir permeability, viscosity, temperature, thickness, Z factor, skin effect and reservoir and wellbore radii. In order to simulate gas kicks in DFD, a proprietary influx model was selected whose rate depended on formation permeability, porosity, length of penetrated reservoir, and the pressure drawdown.

$$P_f^{\,2} - P_{BH}^{\,2} = AQ + BQ^2 \quad \text{(Eq. 6.1)}$$

The gas phase of a kick is immiscible in WBM and migrates up the annulus due to its lighter density. It travels upward even faster due to the mud circulating in the well (Q_{in}) during the application of circulating responses similar to the one shown in Fig. 6.3. Since the pressure is reduced on the gas as it travels up the annulus in a nearly isothermal environment, the gas should expand, as represented by larger bubbles. Consequently, while taking a gas kick in WBM, three components qualitatively contribute to Q_{out} at surface, as can be seen in Fig. 6.3 and Eq. 6.2:

$$Q_{out} = Q_{in} + Q_{res} + \Delta Q_{expansion} \quad \text{(Eq. 6.2)}$$

The flow out of the well, Q_{out} is also related to the pressure drop through the choke. The flow of drilling mud through a choke is mostly subsonic, and hence, Eq. 6.3[102] can sufficiently describe the relation between the pressure drop across the choke and the Q_{out} of the liquid. This equation is modified to present the choke area, rather than diameter, in order to match the DFD choke setting input. In this equation, ρ is the mud density (ppg), A_c is the choked area (sq. in), Q_{out} (gpm), A is a constan, and C is the flow coefficient. Crane[102] (1957) developed a correlation that estimated C to be 0.9 to 1.2 for various ratios of diameters of flow line to choke versus a range of Reynolds numbers.

$$\Delta P_{Choke} = \frac{\rho Q_{out}^{\,2}}{AC^2 A_c^{\,2}} \quad \text{(Eq. 6.3)}$$

The key observation relative to whether inflow has stopped is that applying further choke pressure once formation inflow has stopped will increase the BHP but only reduces the rate of the Q_{out} temporarily. Once the resulting transient has subsided, the gas expansion in the annulus solely controls the increasing rate of Q_{out}, and thus, each transient after a choke opening reduction is expected to be similar. This can be observed in Figs. 5.8, 6.2, 6.4 and simulation results of other circulating responses in Appendix C. Before the influx stops, the transient response of Q_{out} versus time to a change in choke opening includes the change in Q_{res} as implied by Eq. 6.4, and obtained by combining Eq. 6.2 and Eq. 6.3. But when the influx stops and Q_{res} is zero, the transient is dependent only upon the fluid compressibility in the well, and there is no change observed due to flow from the reservoir (Eq. 6.5).

$$\Delta P_{Choke} = \frac{\rho(Q_{in} + Q_{res} + \Delta Q_{expansion})^2}{AC^2 A_c^2} \qquad \text{(Eq. 6.4)}$$

$$\Delta P_{Choke} = \frac{\rho(Q_{in} + \Delta Q_{expansion})^2}{AC^2 A_c^2} \qquad \text{(Eq. 6.5, when influx stops)}$$

This allows confirmation that the influx has stopped, by further choke manipulations. All of the simulations showed that the increasing rate of Q_{out} versus time became minimal when influx stopped. This minimum rate versus time defined a trend that was repeatable by subsequent choke pressure increases (bumping the choke). Therefore, stoppage of inflow determines a minimum in the Q_{out} trend that is repeatable. Consequently, after the trend in Q_{out} versus time was concluded to indicate formation flow had stopped, two equal and arbitrarily selected choke opening reductions of 0.5% and 1% were sequentially applied to all simulated kick scenarios of Well X and Z for a Rapid P_c Incr response. For a Stepwise P_c Incr response, the corresponding choke pressure increases were 50 psi. The results of applying this approach can be seen in the plots of Q_{out} in Figs. 5.6, 5.8, 6.4 and Appendix C.

Fig. 6.5 shows an example of 20 bbl kick taken in Well X from the HP zone with a low permeability where the Circ UB is 1.2 ppge. To confirm the kick stoppage, two unequal steps in decreasing choke size were applied and then plotted for comparison to two equal steps. In each case, the increasing trend in Q_{out} versus time was nearly unchanged. This implies that it is possible to apply a decreasing choke size in order to detect kick stoppage. The significance of this example is that especially when a large gas kick is taken, a very small increase in choke pressure can be used to confirm kick stoppage. This minimizes the extra pressure imposed on the bottom resulting from the kick confirmation procedure. This may be critical in an extremely narrow drilling environment. In Fig. 6.5, the difference between the two confirmation sequences in BHP is about 70 psi.

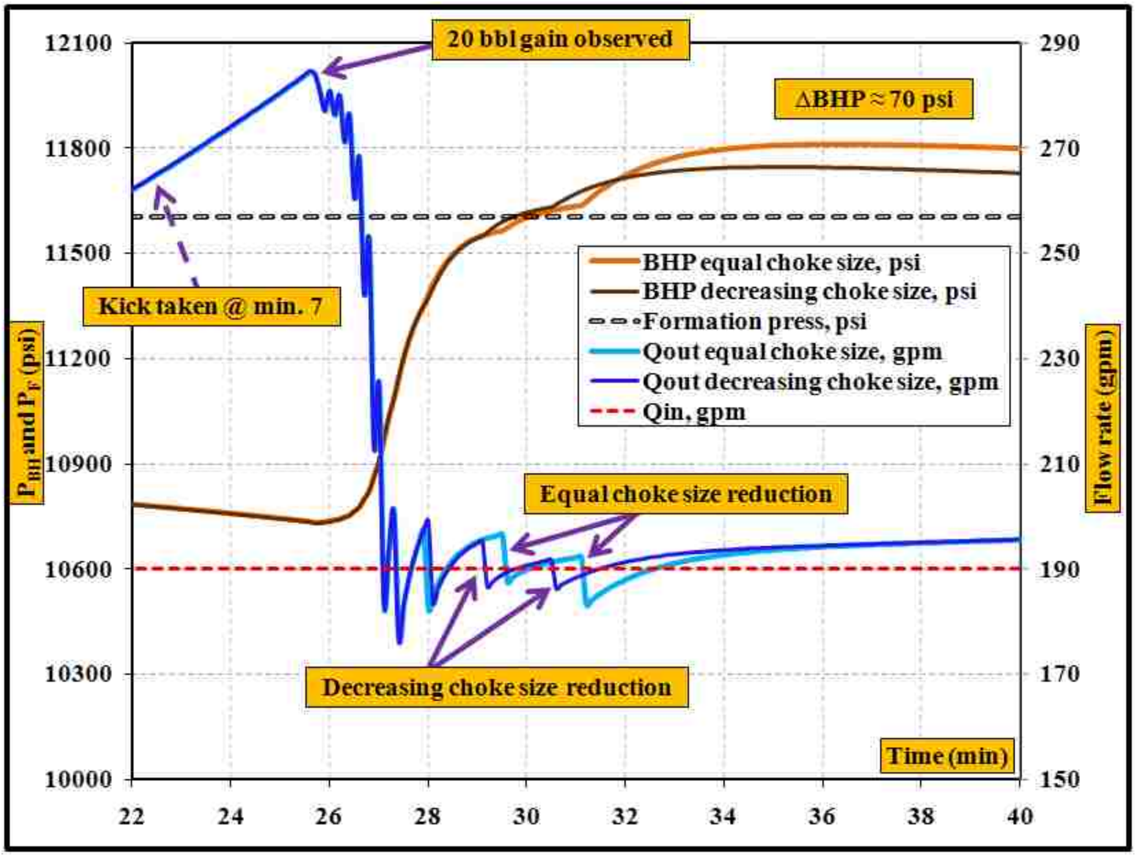


Fig. 6.5: After influx stopped, choke size reduction controls Q_{out} suppression not its trend

Another example that compares high and low k cases is shown in Fig. 6.6. Both plots describe simulations of 20 bbl gas kicks taken in the Well X HP zone with a 0.5 ppge Circ UB. The curves on the left are for the high k simulation, and those to the right, are for the low k kick simulation. The pressure at the shoe, BHP and choke opening are shown on the top plot, and the Q_{out}, Q_{in} and choke pressure on the lower plot. A significant increase in BHP and shoe pressure curves (green color) was experienced for the high k case, after the kick was taken. This is because the large increase in Q_{out} increased the frictional pressure losses in the annulus. There is a smaller increase in BHP and shoe pressure (blue color) for the low k case, which decreased to less than the original values as the kick volume approached the assumed 20 bbl kick detection limit.

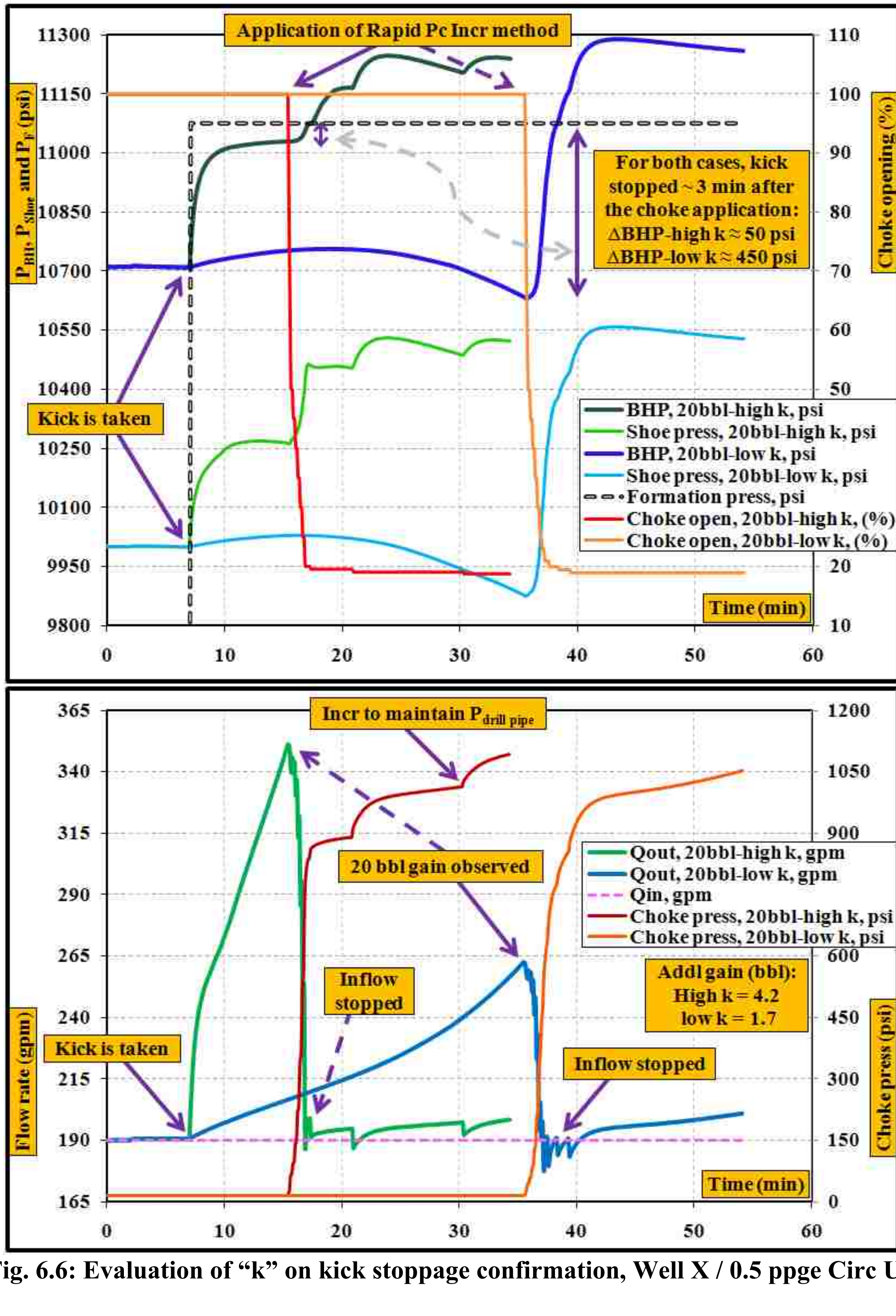


Fig. 6.6: Evaluation of "k" on kick stoppage confirmation, Well X / 0.5 ppge Circ UB

Approximately three minutes after applying the Rapid Choke Incr method, the kick stopped with the choke being about 80% closed for both cases. BHP increased about 450 psi for the low k case and only about 50 psi for the high k case. Overall, the BHP build up to stop the kicks for the high k simulation cases was achieved with minimum choke manipulations, after Q_{out} was reduced to a value close to Q_{in}, whereas more adjustments were required for the low k case, see Fig 6.6 and cases C22 and C46 in Appendix C. Therefore, it was easier to confirm the kick stoppage for the high k kick scenarios compared to the low k cases.

Confirmation of kick stoppage using this approach was even trickier for the 2 bbl kicks, since the Q_{out} was already close to the Q_{in}. However, it was also much less critical because the smaller kick volume causes less expansion, and Q_{out} can be made to nearly equal Q_{in}. Cases C19-21 and C43-45 in Appendix C show the results for small kick sizes.

6.4.1.2 Q_{in} Increase Response

Interpreting the change in the rate in Q_{out} as a tool to confirm that a kick has stopped is difficult when applying this response to a large gas kick. Fig. 6.7 presents results for a 20 bbl kick from the same HP sand in the Well X, but with low k. Since the increased Q_{in} accelerates the gas expansion in the annulus, the expanding gas pushes the mud in front of it faster out of the well, and hence Q_{out} keeps increasing. This rapid expansion prevented both the detection of the minimal rate increase in the trend of Q_{out} versus time and achieving Q_{in} greater than Q_{out} following the kick stoppage as occurred for the 2 bbl kick in Fig. 5.9. In this example, significant P_{AF} has increased the BHP to exceed the formation pressure and the influx is actually stopped, but there is no way to verify that the influx stopped by Q_{out} monitoring. Additionally, the required drill pipe pressure exceeded the capabilities of most drilling rigs. Ultimately, these same complications were experienced in all 20 bbl kick scenarios, and therefore, it is not practical to apply this initial response for high gain cases. Other examples of these cases can be seen in

Appendix C, where annotated on the plots and labeled impractical in the tables. For the 2 bbl kick scenarios, however, a noticeable change in the trend of Q_{out} versus time was identifiable. For these simulations, two 5 gpm Q_{in} increases were applied to evaluate this trend and to confirm the stoppage of kicks which can be seen in the Fig. 5.9 and on the respective cases in the Appendix C.

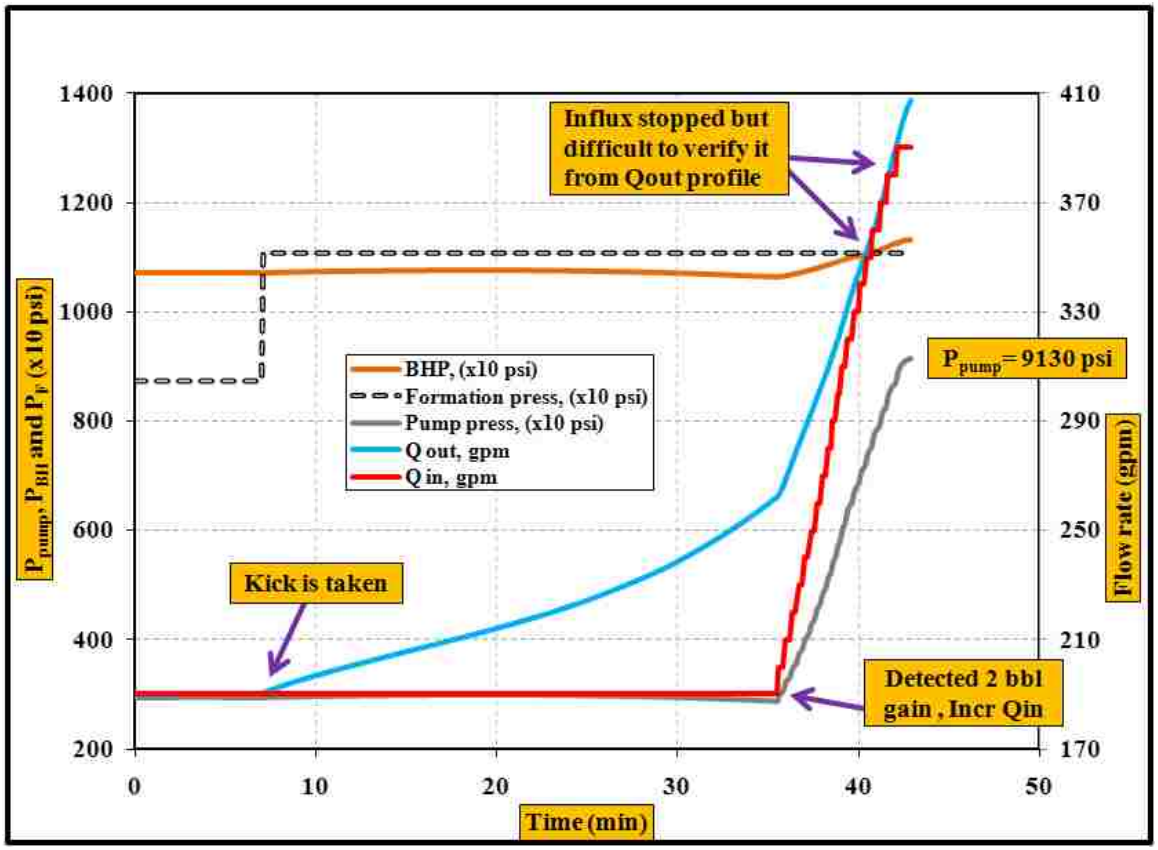


Fig. 6.7: Well X, Stepwise Q_{in} Incr on 20 bbl kick / low k / 0.5 ppge Circ UB

6.4.1.3 Summary of the Kick Influx Stoppage Confirmation for Circulating Responses

With a flow rate out, Q_{out} interpretation is required to determine whether a gas influx has stopped for circulating initial responses, CRs. This interpretation was not difficult for 2 bbl kick scenarios, and for a variety of well geometries and, reservoir conditions, Q_{out} was almost equal to Q_{in} when influx stopped. For 20 bbl kicks however, Q_{out} could not be generally forced to equal Q_{in}, and visually, it was difficult to confirm a kick stoppage. However for the responses that applied choke pressure to control the kick, a method of applying repetitive choke pressure increases served to identify a repeatable transient behavior in Q_{out} to confirm that formation influx had stopped. This method was successful for determining the kick stoppage for Well X and Z kick scenarios, but its application had not been quantified. Unfortunately, the confirmation of kick stoppage for the Q_{in} increase response was practically impossible for large kicks, as the gas expansion offset the change of Q_{out} trend that occurred upon kick stoppage.

6.5 Comparison of Initial Responses

Results of the application of the alternative initial responses on the broad spectrum of the Well X and Z kick scenarios are discussed in this section. Nine initial responses in two categories, non-circulating and circulating responses (NCRs and CRs), were investigated in this research. A good, reliable response should be effective, regardless of the hole size, formation pressure, and permeability. These conditions may cause some of the responses to function inefficiently. Therefore, an effective way to discuss the simulation results of a response to kicks is to present its application versus a range of kick scenarios. Also, a logical approach to determine the best initial response, or responses, is to compare the NCRs and CRs independently before comparing the best of each.

6.5.1 General Significance of Kick Scenario Variables

Some general observations were commonly seen throughout the simulations of the different kick scenarios. These will be discussed so that the significance of Circ UB, initial gain, permeability, and well geometry can be more easily deduced.

6.5.1.1 Kick Detection Limits

The simulation examples of the initial responses to 2 bbl kicks, introduced in Chapter 5, assumed that sensitive kick monitoring equipment was in service, such as an accurate flow out meter, which allowed early kick detection. Conversely, a large kick, assumed to be 20 bbl in this study, is expected before being detected with conventional kick detection equipment. Fig. 6.8

compares the results of three SI simulations. It includes application of the SI response on the same 2 bbl kick from the Well X HP zone (high k and 0.5 ppge Circ UB), which was discussed in Chapter 5 (Fig. 5.1). If a 20 bbl kick is taken while drilling into the same HP zone, retaining the same PP and k, a higher choke pressure is required to stop the influx as seen on the plot. The choke pressure for this case stabilizes at around 1500 psi, which indicates an increase of about 400 psi, compared to the 2 bbl kick case. This is simply due to a larger loss of hydrostatic pressure, which also increases the pressure drawdown at the kick zone and the influx rate from the reservoir, as compared to a 2 bbl kick. Therefore, higher choke pressure and additional gain are experienced for the 20 bbl kick case. Additionally, the larger gas influx travelling up the annulus increases the void fraction more significantly, causing a larger slope of choke pressure versus time than in 2 the bbl case.

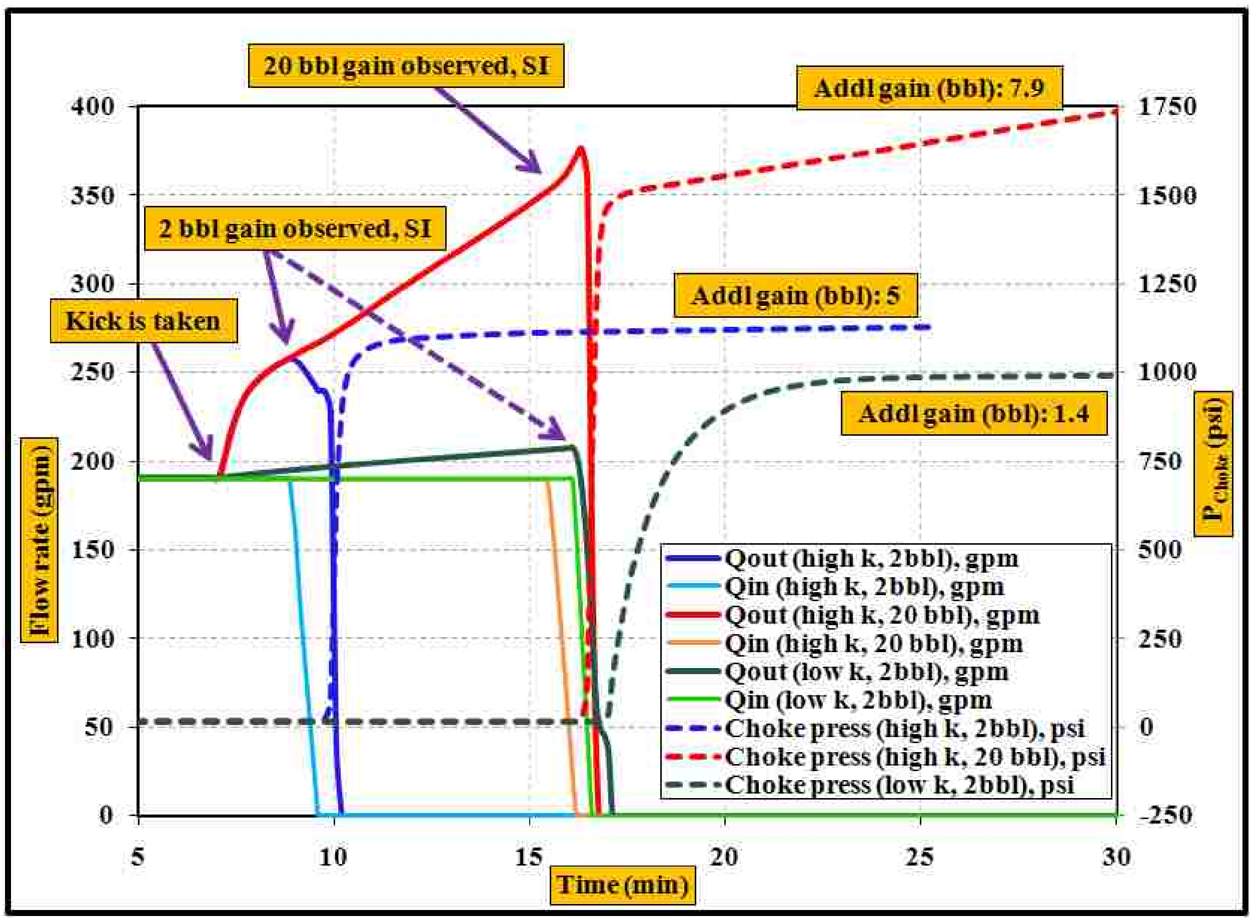


Fig. 6.8: Well X, SI on 2 & 20 bbl kick / high k versus 2 bbl / low k (0.5 ppge Circ UB)

The higher choke pressure increases the risk of exceeding the pressure limits of the surface equipment and of the integrity of the shoe. Overall, these conditions are the penalty for less accurate kick monitoring and a resulting 20 bbl kick. The pressure at the shoe when the kick was stopped, as well as the additional gain until influx stopped, were also higher for 20 bbl kicks compared to 2 bbl kicks. This effect on the pressure at the shoe and additional gain were also generally true for the circulating responses. Exceptions may be due to the effects of circulation for CRs, as well as the location of the gas column in the annulus relative to the shoe and surface.

6.5.1.2 Formation Permeability

Fig. 6.8 also shows results for a 2 bbl kick taken in Well X with the same formation pressure (0.5 ppge Circ UB), but the permeability is reduced to 5 mD (low k). In this case, choke pressure stabilizes at around 1000 psi, which is 100 psi less than the similar high k case. Although formation pressure and initial kick size are similar between the high and low k cases, the choke pressure required to stop the kick is different. This is due to the larger additional gain in the high k case. Simulation results of the NCRs and CRs also showed that generally, for the same kick size and formation pressure, the high k cases resulted in higher choke pressure, pressure at the shoe, and larger additional gain, compared to the respective responses for low k cases. Exceptions sometimes exist due to the effect of the location of gas in the annulus.

6.5.1.3 Underbalance when Kick is Taken

The application of the SI response on a 2 bbl kick, taken after drilling into the Well Z HP sand at 4500 ft MD with high k, is shown in Fig. 6.9. In this plot, the SI responses are shown for different levels of Circ UB, given as a ppg equivalent in parentheses on the legend. It can be seen, as the formation PP and Circ UB increases, that the HP zone delivers larger influx rates, allowing a 2 bbl kick to be achieved earlier. It can be simply and intuitively deduced that the larger the Circ UB, the higher the choke pressure required to stop the influx. Simulation results of the non-circulating and circulating responses showed that for the same kick size and permeability, the choke pressure and the pressure at the shoe when the kick was stopped increased directly with a larger Circ UB. Generally, the additional gain before the influx stopped also increased directly with the larger Circ UB.

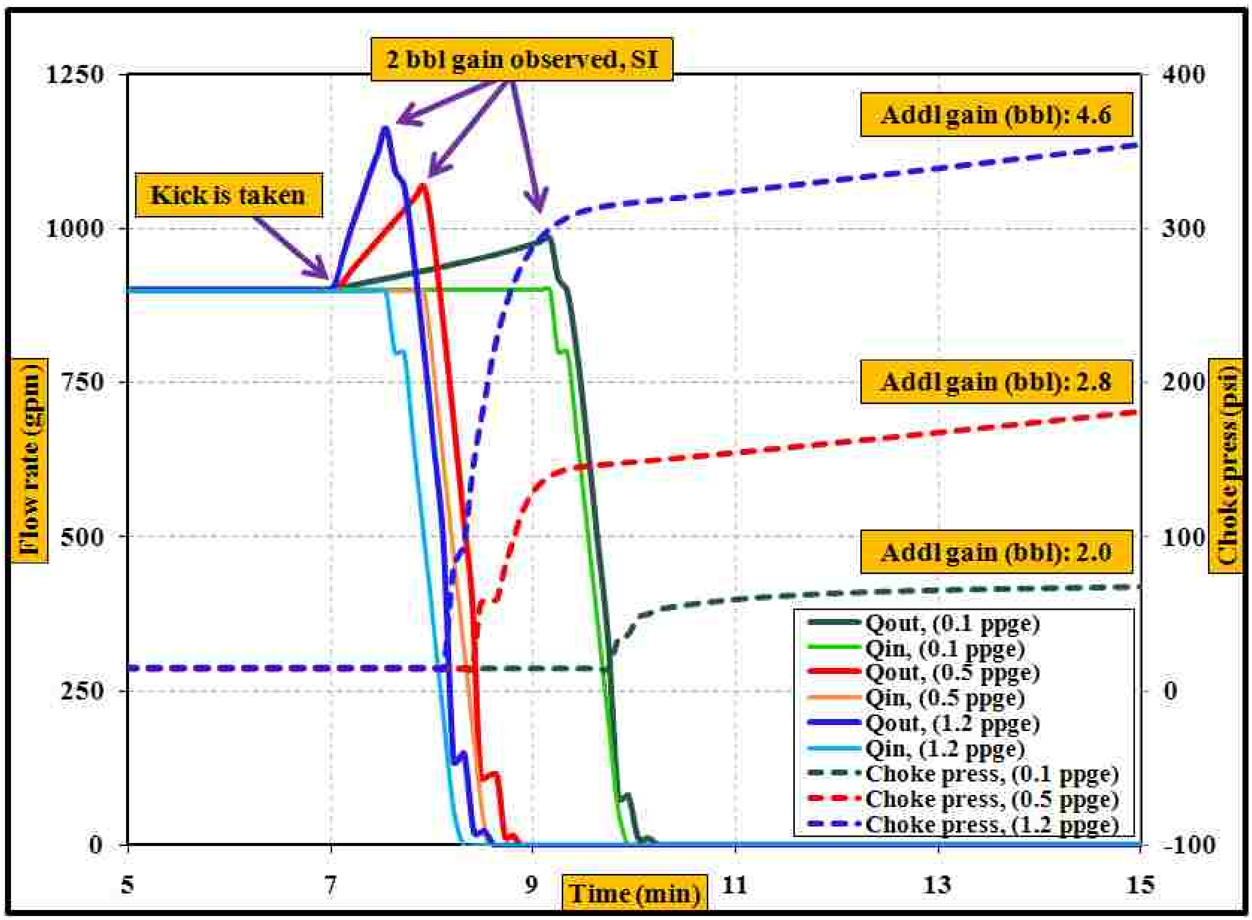


Fig. 6.9: Well Z, SI on 2 bbl kick / high k versus different levels of the Circ UB

6.5.1.4 Summary for Well X

Table 6.2 tabulates the simulation data from the application of the SI response to the complete range of Well X kick scenarios. A more complete data summary is provided in Appendix C. However, this table is shown as an example of the kick scenario observations that were discussed. There are minor exceptions to the general observations that primarily pertain to the additional gain taken while a kick was being stopped.

Table 6.2: Applications of SI response on Well X kick scenarios

High k (500 mD permeability)				
Init gain	Circ UB @ 190 gpm	Choke press (psi)	Shoe press (psi)	Addl gain (bbl)
2 bbl	0.1 ppge	736	10321	3.2
	0.5 ppge	1095	10665	5.0
	1.2 ppge	1656	11223	5.9
20 bbl	0.1 ppge	1160	10400	5.1
	0.5 ppge	1506	10753	7.9
	1.2 ppge	2034	11316	7.1
Low k (5 mD permeability)				
Init gain	Circ UB @ 190 gpm	Choke press (psi)	Shoe press (psi)	Addl gain (bbl)
2 bbl	0.1 ppge	686	10257	1.5
	0.5 ppge	984	10571	1.4
	1.2 ppge	1524	11116	1.6
20 bbl	0.1 ppge	1199	10359	5.0
	0.5 ppge	1419	10641	3.5
	1.2 ppge	1943	11178	4.1

6.5.1.5 Well Geometry

A 20 bbl kick taken on the bottom of Well X results in more loss of hydrostatic head, compared to Well Z, due to its smaller hole size to BHA clearance. Additionally, the frictional pressure losses are minimal in Well Z due to its larger hole size to BHA clearance. Consequently, the simulation results of NCRs and CRs in Well Z generally showed less sensitivity to kick detection limits, i.e., 2 versus 20 bbl kick scenarios. The corresponding results in Well X are more significant, which may also be seen in Table 6.2. These results also suggest that the initial responses in slim hole applications may experience more severe consequences in regards to higher kick detection limits or higher reservoir productivity.

6.5.2 Non-Circulating Responses (NCRs)

The non-circulating initial responses (NCRs) described in Chapter 5 were: SI (NCR1), MPD pump SD W/ CFC and SI (NCR2), MPD pump SD and SI (NCR3), Auto MPD pump SD W/ CFC and SI (NCR4), and Auto MPD pump SD and SI (NCR5). In this section, these responses are compared, based on simulation results.

Figs. 5.1, 5.2, 5.3, 5.4, and 5.5, which introduced the application of the NCRs on the 2 bbl kick scenario in Well X, showed that all of these successfully stopped the kick, yet the SI was the fastest. This is clearly evident from the green marker on the BHP curves. Figs. 5.2, 5.3, 5.4, and 5.5 further illustrated that the formation was flowing at all times during the application of MPD pump SD responses until the well was shut-in. Therefore, additional kick volume entered the well, which required additional choke pressure to offset the loss of hydrostatic. Consequently, higher pressure was imposed on the casing shoe. The evaluation criteria for the best initial response, explained in Chapter 3, requires a fast response which in turn minimizes the risk to the well; hence, the SI response was the best NCR for this kick scenario.

Table 6.3 illustrates the simulation results for this particular kick scenario (case C2 in the Appendix C). It confirms that the SI response (NCR1) poses the least risk to the surface equipment and the casing shoe, compared to the other responses.

Table 6.3: Well X, applications of the NCRs on 2 bbl kick / high k / 0.5 ppge Circ UB

Data is reported at the kick stoppage				
Case Code	**Initial response**	**Choke press (psi)**	**Shoe press (psi)**	**Addl gain (bbl)**
C2	**NCR1**	**1095**	**10665**	**5.0**
	NCR2	**1842**	**10827**	**42.3**
	NCR3	**1606**	**10776**	**30.4**
	NCR4	**1372**	**10777**	**16.9**
	NCR5	**1166**	**10678**	**8.3**

Fig. 6.10 shows the application of the NCRs on a 20 bbl kick from the Well X HP zone with high k and 0.1 ppge Circ UB (case C4 in the Appendix C), where the flow rates and choke pressures are plotted versus time. A brief increase in the Q_{out} after the application of SI response is due to the loss of the P_{AF} as the result of shutting down the mud pump before closing the choke. The Q_{in} for the MPD pump SD responses are exactly the same as the Q_{in} shown by the no kick fingerprint curves and therefore, are not plotted.

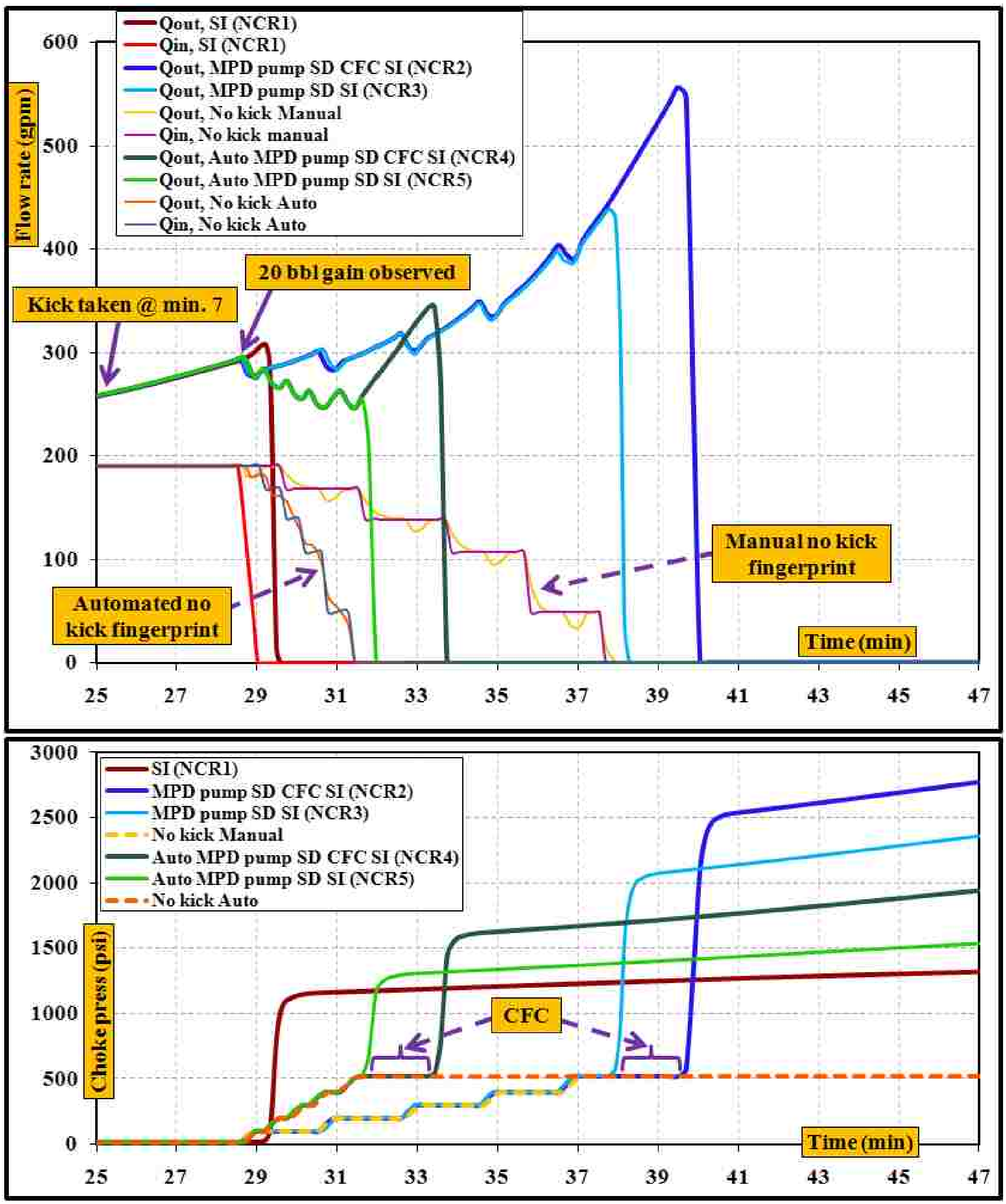


Fig. 6.10: Well X, application of the NCRs on 20 bbl kick (high k, 0.1 ppge Circ UB)

A significant separation between the Q_{out} and the Q_{in} curves reveals that the well was flowing during the application of all the MPD pump SD responses. The influx rate even increased considerably during the "choked flow check" period (marked CFC in Fig. 6.10), when used in a MPD pump SD response, because the required P_c was not enough to contain the influx.

Additionally, the manual MPD pump SD responses were slow, and hence allowed the well to be underbalanced for a longer time. Consequently, a larger influx entered into the well, compared to the automated responses. The SI response (NCR1) however, stopped the influx faster than all of the MPD pump SD responses, as evidenced in Table 6.4. The SI response also resulted in the least additional gain and the least pressure imposed, on the surface equipment and the shoe.

Table 6.4: Well X, applications of the NCRs on 20 bbl kick / high k / 0.1 ppge Circ UB

Data is reported at the kick stoppage				
Case Code	**Initial response**	**Choke press (psi)**	**Shoe press (psi)**	**Addl gain (bbl)**
C4	**NCR1**	**1160**	**10400**	**5.1**
	NCR2	**2531**	**10604**	**71.2**
	NCR3	**2066**	**10534**	**49.0**
	NCR4	**1610**	**10537**	**25.8**
	NCR5	**1303**	**10430**	**12.3**

It is observed from the 2 bbl and the 20 bbl kicks discussed to this point, that all of the NCRs ultimately stopped the simulated kicks in the assumed intact wellbore. However, the MPD pump SD responses, either manual or automated, allowed additional kick to enter into the well. Consequently, this would cause more complications to the control of the well if the responses were taken as the initial response to a flowing well because the influx rate was intensified due to the increasing loss of hydrostatic pressure during the MPD pump SD schedule. In contrast the SI response minimizes the duration that the well is underbalanced, and therefore this was the best response for both cases shown. Moreover, the SI response is the best response for Well Z because all of the MPD pump SD responses were not applicable due to low P_{AF}. Even if proper wellbore and BHA geometries would reasonably allow a pump SD schedule to be constructed, the SI response would yet be the best response to a flowing Well Z, similar to the Well X cases. Thus, with regard to all the facts mentioned above, and based on other simulation results in Appendix C for the Well X and Z kick scenarios, the SI response was the most generally successful response among the NCRs.

A practical application for the MPD pump SD responses was realized during the simulation of the least severe kick scenario for Well X. This case (case C7 in the Appendix C) is a 2 bbl kick from the HP zone with a low k and 0.1 ppge Circ UB, as shown in Fig. 6.11, where the well had been flowing over 20 minutes before the assumed kick detection limit was reached.

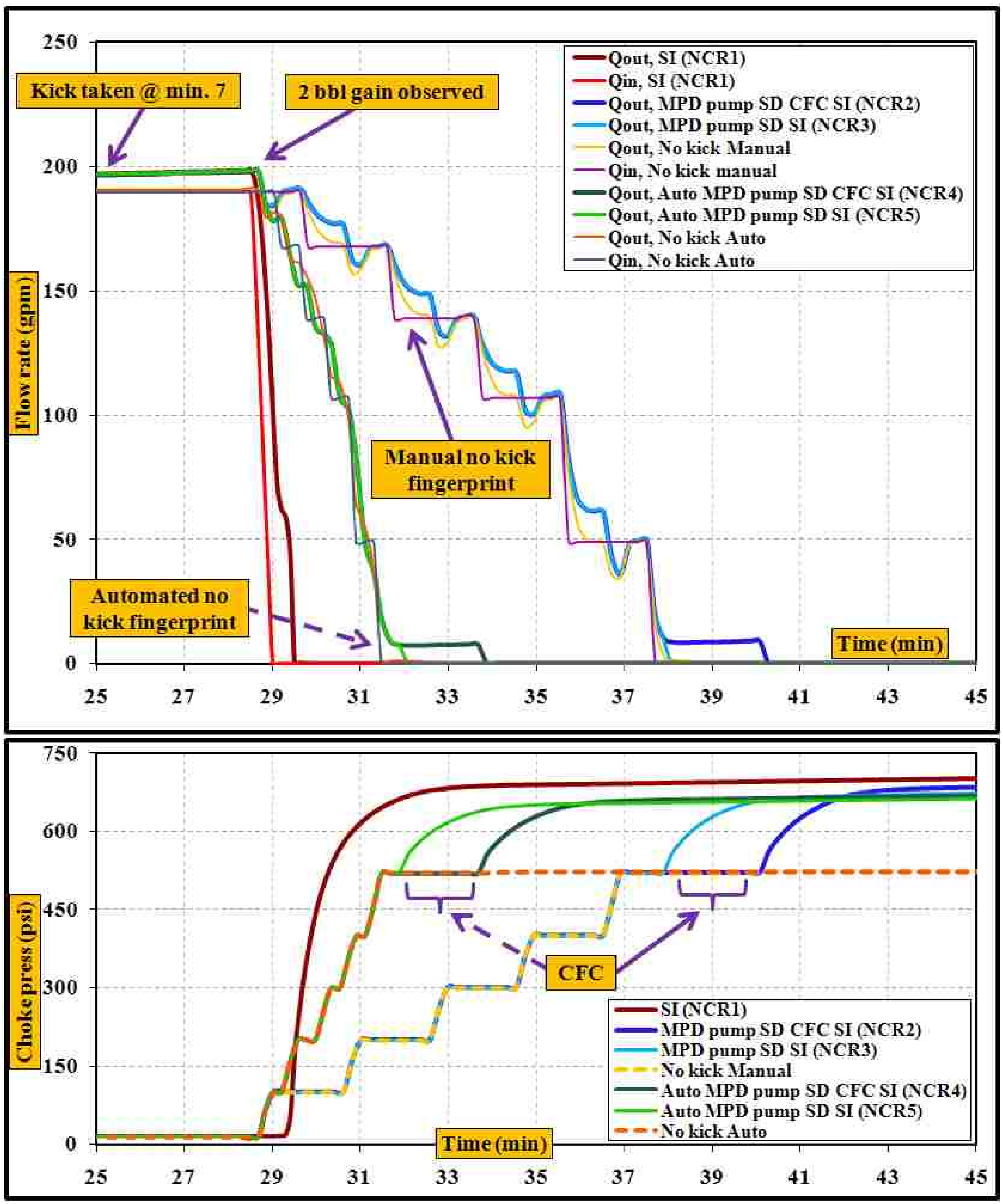


Fig. 6.11: Well X, application of the NCRs on 2 bbl kick (low k, 0.1 ppge Circ UB)

There is no significant difference in the Q_{out} versus time between the MPD pump SD responses and the no kick fingerprints. Consequently, during a kick incident with such low intensity, it would be difficult to conclude that the well was flowing, based on the Q_{out} profiles during a MPD pump SD. However, a choked flow check, CFC at the end of the pump SD can determine whether a kick is occurring or not. If a kick is taken, then the final P_c on the SD schedule is insufficient to contain the well. Thus, the Q_{out} continues, even increasing slightly during the CFC, as shown in Fig. 6.11. Subsequently, a casing pressure buildup will be observed after the well is SI, which confirms that the well was flowing. A similar buildup will also be experienced after a normal MPD pump SD and SI, or a simple conventional SI. However, these buildups could be due to trapped pressure. Therefore, it would be necessary to bleed choke pressure to check for trapped pressure in order to conclusively determine whether a kick occurred or not. Consequently, the MPD pump SD responses that end in a CFC have an advantage in detecting a weak, suspected kick, or an undetected kick during a connection, versus other NCRs.

Fig. 6.11 illustrated a higher choke pressure for the SI response despite stopping the influx faster than all of the MPD pump SD responses. This is primarily due to the loss of P_{AF} during the mud pump shut down, which increased the influx rate from the kick zone prior to closing the choke. The MPD pump SD responses did not allow a large BHP drop due to the P_{AF} and P_{back} applied during the step-wise schedule, although it took a longer time to implement them. This advantage was due to both low differential pressure at the kick zone and low permeability and the resulting low productivity associated with this kick scenario. The lower additional gains for MPD pump SD responses, therefore, caused the lower choke pressure and pressure at the shoe versus a simple SI for this case, see Table 6.5.

Table 6.5: Well X, applications of the NCRs on 2 bbl kick / low k / 0.1 ppge Circ UB

Data is reported at the kick stoppage				
Case Code	Initial response	Choke press (psi)	Shoe press (psi)	Addl gain (bbl)
C7	NCR1	686	10257	1.5
	NCR2	680	10234	1.6
	NCR3	667	10221	1.1
	NCR4	660	10226	0.7
	NCR5	651	10217	0.4

6.5.2.1 Summary of the Best Non-Circulating Responses

Table 6.6 summarizes the application of the NCRs on 4 different Well X kick scenarios including 2 and 20 bbl kicks versus high and low k for the same Circ UB of 0.5 ppge.

Table 6.6: Well X, applications of the NCRs (0.5 ppge Circ UB)

Data is reported at the kick stoppage, (Data in red if $P_{shoe} > P_{FP}$)				
Case Code	Initial response	Choke press (psi)	Shoe press (psi)	Addl gain (bbl)
2 bbl High k (C2)	NCR1	1095	10665	5.0
	NCR2	1842	10827	42.3
	NCR3	1606	10776	30.4
	NCR4	1372	10777	16.9
	NCR5	1166	10678	8.3
Case Code	Initial response	Choke press (psi)	Shoe press (psi)	Addl gain (bbl)
20 bbl High k (C5)	NCR1	1506	10753	7.9
	NCR2	3421	10932	100.6
	NCR3	2762	10855	69.3
	NCR4	2070	10870	35.2
	NCR5	1687	10779	17.4
Case Code	Initial response	Choke press (psi)	Shoe press (psi)	Addl gain (bbl)
2 bbl Low k (C8)	NCR1	984	10571	1.4
	NCR2	1058	10588	4.9
	NCR3	1029	10569	3.9
	NCR4	1000	10573	2.2
	NCR5	975	10553	1.3
Case Code	Initial response	Choke press (psi)	Shoe press (psi)	Addl gain (bbl)
20 bbl Low k (C11)	NCR1	1419	10641	3.5
	NCR2	1971	10725	29.8
	NCR3	1804	10675	22.1
	NCR4	1603	10687	11.8
	NCR5	1474	10635	6.4

It is evident, based on this discussion, the table shown, and Appendix C that the SI response is the most successful response among all the NCRs for the cases studied. The MPD pump SD responses without a CFC have shown no significant advantages overall. At the best, the automated MPD pump SD and SI response (NCR5) is a poor alternative to the SI response (NCR1), due to simulation results that are close to those for the SI response. The MPD pump SD responses that end in a CFC (NCR2 and NCR4) carry a particular advantage. They permit a choked flow check that identifies a questionable, very low rate or undetected kick. Either is a valuable response for these situations where a SI response may not be justified.

6.5.2.2 Advantages of the Best Non-Circulating Responses

There are several advantages in applying the SI response (NCR1). The most important value is its simple operational procedure, which can be completed quickly in about one minute. This reduces the extra kick volume entering the well. It is also the primary well control procedure for the conventional applications. Additionally, the conventional well control wisdom requires that a well must be shut-in where there is an uncertainty regarding the appropriate conduct of the well control procedure or in the case of any surface equipment failure. Therefore, it is a well-known response in the industry, and its benefits extend to MPD applications as well. The interpretation of the pressure data following a SI allows determination of the HP zone PP, which is useful for controlling the kick. A SI response is also possible by the application of the rig choke and the BOP, which allows higher pressure ratings. It may also be implemented without requiring any special equipment such as flow out metering, an automated choke or hydraulics modeling. Finally, it can minimize the risk of loss of returns at a depth below a shallower HP kick zone[91].

The primary advantage of the MPD pump SD W/ CFC and SI response (NCR2) lies in its inherent capability to detect low rate kicks during the CFC, which is an adaptation of a conventional flow check. Therefore, it can be applied regularly for flow checks, including on connections. Since it ends in SI, it has similar advantages to a SI response, such as determining the formation PP and minimizing the risk of lost returns on bottom, as explained above.

6.5.2.3 Limitations or Disadvantages of the Best Non-Circulating Responses

Table 6.7 presents the results of the best NCRs (NCR1 and NCR2) to 20 bbl kicks from the Well X HP zone with high and low k (Case C5 and C11) and the same Circ UB of 0.5 ppge. While the choke pressure, pressure at the shoe, and additional gain when the kick was stopped were shown in Table 6.6 for the same kick scenarios, here the choke and shoe pressures are shown ten minutes after the kick stoppage. The high increase in the choke pressure within ten minutes after the kick stoppage shows that gas is migrating in the annulus, which gradually elevates the surface and shoe pressures. Consequently, the pressure applied to the shoe may exceed what the shoe can tolerate. In those cases, the shoe pressure is shown in red. This data simply reveals that both responses increase the risk of lost returns, as the casing pressure builds up due to gas migration. There is also a significant complication in the determination of the formation PP or detection of an ongoing loss of returns after the well is shut-in when a NRV is used in the BHA because it prevents reading drill pipe pressure versus time. A NRV is a necessity for MPD operations that are statically underbalanced. These are the common disadvantages of responses ending in SI.

Non-circulating responses also require a pump start up procedure to control the kick. This generally increases the NPT versus circulating responses. In addition, pump start ups and shut downs typically cause pressure fluctuations that can increase the risk of excessive pressures. A hard SI will also typically trap some pressure in the well, which relates to the NCR1, NCR3, and NCR5 cases as explained specifically for NCR3 in Chapter 5.

The main disadvantage of the MPD pump SD W/ CFC and SI response (NCR2) is related to its application. It can be the worst initial response if it is applied to a known kick (shown on previous sections) because it will allow a large additional gain into the well and thus seriously complicate the well control operation.

Table 6.7: Well X, applications of the best NCRs on 20 bbl kicks / 0.5 ppge Circ UB

Data is reported 10 minutes after kick stoppage, (Data in red if $P_{shoe} > P_{FP}$)			
Case Code	**Initial response**	**Choke press (psi)**	**Shoe press (psi)**
C5 (high k)	**NCR1**	**1692**	**10848**
	NCR2	**3880**	**11144**
C11 (low k)	**NCR1**	**1497**	**10688**
	NCR2	**2249**	**10910**

6.5.3 The Best Circulating Responses (CRs)

The initial Circ responses (CRs) described in Chapter 5 include: Stepwise P_c Incr (CR1), Incr P_c to 80% of MAASP (CR2), Rapid P_c Incr (CR3), and Stepwise Q_{in} Incr (CR4). In this section, the results of simulating these responses are discussed.

Fig. 6.12 shows the application of all of CRs, which were individually introduced by Figs. 5.6, 5.7, 5.8, and 5.9 on the 2 bbl kick scenario in Well X (high k, 0.5 ppge Circ UB). It was shown in Chapter 5 that all of the CRs successfully stopped the kick. Table 6.8 tabulates the results of these responses to one kick scenario, where data is given at the time that the kick is stopped.

Table 6.8: Well X, applications of the CRs on 2 bbl kick / high k / 0.5 ppge Circ UB

Data is reported at the kick stoppage				
Case Code	**Initial response**	**Choke press (psi)**	**Shoe press (psi)**	**Addl gain (bbl)**
C14	**CR1**	**490**	**10401**	**2.6**
	CR2	**465**	**10413**	**1.0**
	CR3	**455**	**10405**	**1.7**
	CR4	**15**	**10241**	**2.4**

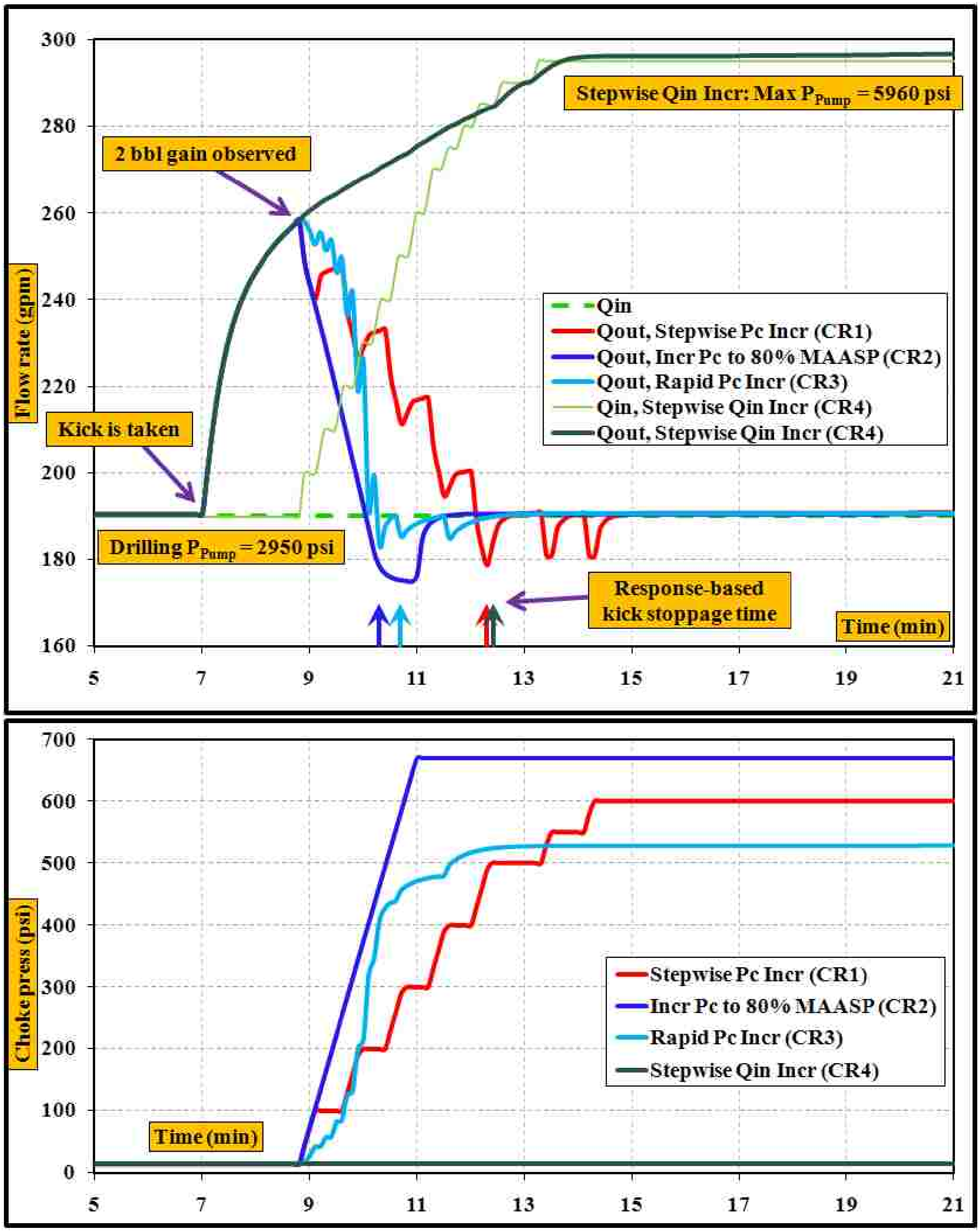


Fig. 6.12: Well X, application of the CRs on 2 bbl kick (high k, 0.5 ppge Circ UB)

It is evident from Fig. 6.12 and Table 6.8 that CR2 stopped the kick faster than the others resulting in the least additional gain. However, as explained in 5.3.2.1, this was due to a large pressure (670 psi) applied rapidly to the choke. Consequently, after the choke pressure was established, this response had the largest pressure applied to the surface casing and shoe, as well as at bottom (refer also to case C13 in Appendix C). Application of CR4 resulted in the least surface and shoe pressure because this response only utilizes the ECD to stop the kick. However, drill pipe pressure increased to a maximum of 5960 psi, which was the highest among all CRs. CR1 had a larger additional gain, compared to others, because the manual application of choke pressure was slower than for simulated automated responses, thus allowing a larger gain before it stopped the kick. Application of CR3 was successful and resulted in lower choke pressure than CR1 and CR2.

The success of the CRs depend on parameters such as well design and kick detection limits, as explained in Section 5.1. For the example shown in Fig. 6.12, Well X has a 1.15 ppge kick margin at the shoe (at 190 GPM, refer to Table 4.2) and could tolerate a 2 bbl kick from the HP zone with the Circ UB of 0.5 ppge. With such a strong shoe, relative to the kick severity and the 2 bbl kick size, based on accurate kick detection equipment, the CRs all proved to be fast and efficient. A more severe kick scenario might challenge the effectiveness of the CRs.

An example of the above discussion may be seen after the application of all CRs on a 20 bbl kick scenario in Well X (high k, 0.5 ppge Circ UB), shown in Fig. 6.13. The 20 bbl kick volume, when detected, was selected to represent kick detection with conventional equipment. In this plot, Q_{in}, Q_{out} and choke pressure versus time for the respective responses are shown. For CR2, the pressure equal to 80% of MAASP was insufficient to contain the well. Therefore, the well continued flowing, and Q_{out} kept increasing, as marked by “uncontrolled” on the figure. Hence, this response was not successful for this case. For Stepwise Q_{in} Incr, CR4, BHP data indicated that the kick was stopped (where the arrow is) by increased ECD in the open hole. Table 6.9 shows that shoe pressure at kick stoppage for CR4 is even less than pressure at the shoe for the 2 bbl kick shown in Table 6.8 (same Circ UB). This is because of a more elevated ECD below the shoe. Kick stoppage confirmation became difficult for the Q_{out} behavior due to the rapid expansion of gas in the annulus noted in Section 6.4.1.2. Furthermore, the drill pipe pressure required to stop the kick for CR4 exceeded the capabilities of most drilling rigs. Consequently, CR4 was not conducted to be useful for this kick scenario.

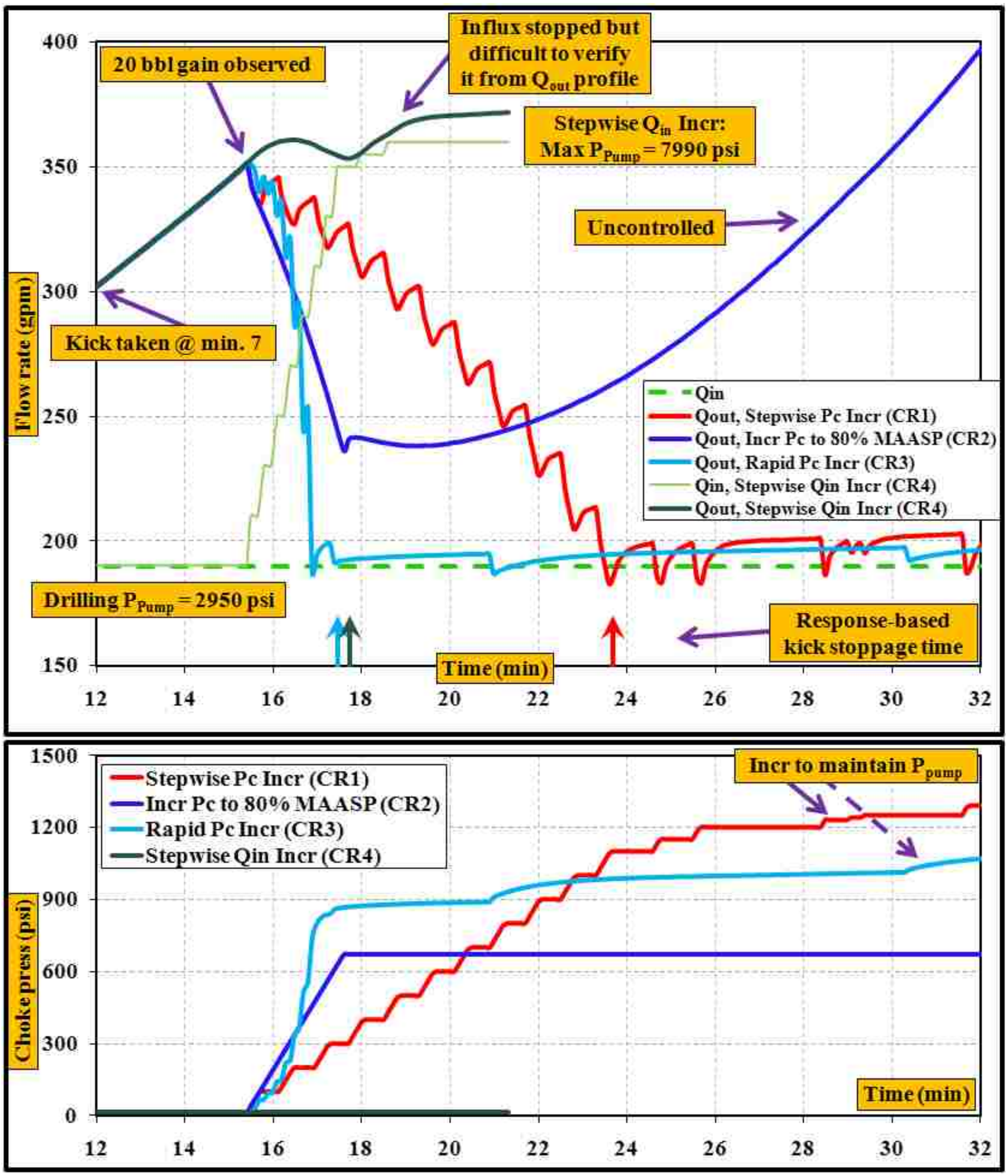


Fig. 6.13: Well X, application of the CRs on 20 bbl kick (high k, 0.5 ppge Circ UB)

The Rapid P_c Incr (CR3) and the Stepwise P_c Incr (CR1) methods stopped the kick effectively. The CR3 method stopped the kick faster. Table 6.9 shows that CR3 only allowed an additional 4.2 bbls of gain, while CR1 allowed an additional 17.9 bbls. The large gain resulted from the longer time required to implement this response. Consequently, it had a larger choke pressure than the rapid method, as seen in Table 6.9. This is opposite to what is seen for the pressure at the shoe. The BHP at the kick stoppage and the mud circulation rate are equal for both methods, and knowing that the wellbore is intact in DFD simulations, the lower shoe pressure for CR1 is due to less gas in the annulus below the shoe despite a larger kick volume in the well. The larger gas kick in the annulus for the CR1 method also presents increased potential risks at the surface. Therefore, the Rapid P_c Incr method, CR3, was a more successful response for this kick scenario. It stopped the kick faster without breaking the shoe and resulted in lower choke pressure.

Table 6.9: Well X, applications of the CRs on 20 bbl kick / high k / 0.5 ppge Circ UB

Data is reported at the kick stoppage				
Case Code	**Initial response**	**Choke press (psi)**	**Shoe press (psi)**	**Addl gain (bbl)**
C17	**CR1**	**1100**	**10399**	**17.9**
	CR2	**Uncontrolled**	**Uncontrolled**	**Uncontrolled**
	CR3	**865**	**10458**	**4.2**
	CR4	**15**	**10147**	**4.1**

The results of the 2 and 20 bbl kick examples from Tables 6.8 and 6.9 show that a 20 bbl kick resulted in significant additional choke pressure and additional gain. This is due to a larger loss of hydrostatic head for a 20 bbl kick in the slim wellbore of Well X compared to the 2 bbl kick. This difference is much smaller for the large wellbore of Well Z (Well Z Cases C38 and C41 in Appendix C). Consequently, the penalty for poor kick detection equipment is substantial for well control incidents in slim hole MPD operations.

A Circ UB of 1.2 ppge can create a kick severity that the design of Well X cannot tolerate. However, the simulation of such kicks can determine the effectiveness of the CRs for kick scenarios that were not planned, which often happens in real field applications. Additionally, an initial response that can stop such a kick successfully is important.

Fig. 6.14 demonstrates an example of the application of CRs to a 20 bbl kick in Well X with high k and Circ UB of 1.2 ppge, which is the most severe kick scenario. The Q_{out} for all CRs are plotted versus time. The tabulated results of the choke and the shoe pressure at the kick stoppage, as well as additional gain, are presented in Table 6.10.

The Incr P_c to 80% of the MAASP method, CR2, was not enough to contain the formation pressure, and the well continued flowing. The response was not successful for this case. Neither was the Stepwise P_c Incr method, CR1, effective for this kick. This was due to the slow manual increase in choke pressure to a kick with larger well deliverability. The jagged Q_{out} profile was due to the application of 100 psi choke pressure increments. The stepwise increase of choke pressure was apparently slower than the loss of hydrostatic with a high influx rate, and thus the application of this response was not effective.

The Rapid P_c Incr method, CR3, however stopped the kick and only allowed 5.6 bbls of additional kick. The pressure applied at the shoe when the kick stopped for the CR3 method exceeded the casing shoe limits, shown in red color on Table 6.10. This is a constraint in the design of Well X and does not undermine the general effectiveness of the CR3 method. The results do reinforce that different responses may be required for different well conditions.

The Stepwise Q_{in} Incr method, CR4, stopped this kick without pressure at the shoe that exceeded the fracture pressure. This is a general advantage of the CR4 method, in that it minimizes the risk of losing returns at the shoe versus all other responses investigated. On the other hand, the application of this response requires careful planning. As shown in Fig. 6.14, the drill pipe pressure went far beyond what any rig pumps are currently rated for. Therefore, special BHA and/ or hydraulics designs are required for application of this response to be relied on in practice. In addition, it is difficult to confirm whether a kick was stopped due to the increasing rate of the Q_{out}. This problem is a general weakness of this response, when applied to large kicks. Moreover, the mud-gas separator must also be capable of handling the high surface fluid rates.

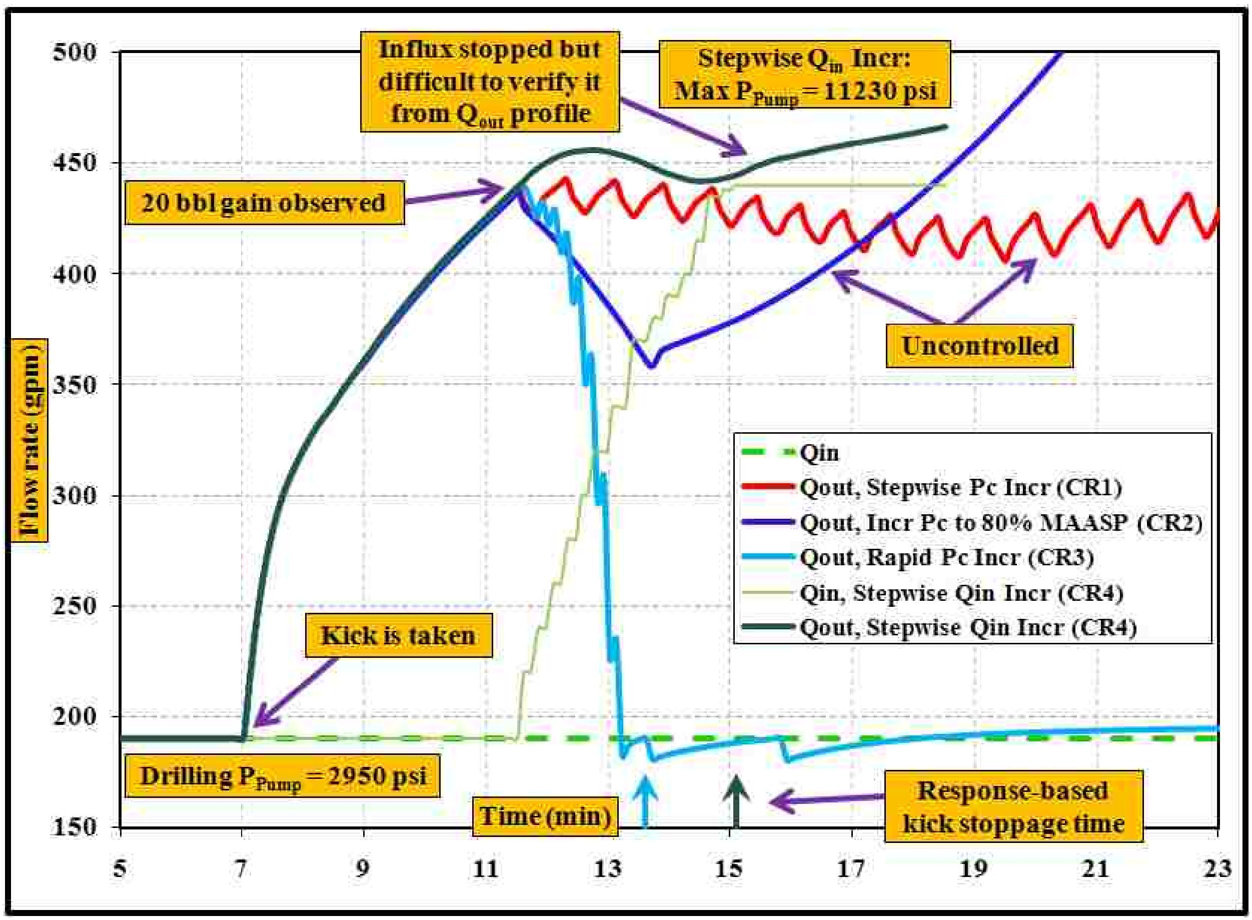


Fig. 6.14: Well X, application of the CRs on 20 bbl kick (high k, 1.2 ppge Circ UB)

Table 6.10: Well X, applications of the CRs on 20 bbl kick / high k / 1.2 ppge Circ UB

Data is reported at the kick stoppage, (Data in red if $P_{shoe} > P_{FP}$)				
Case Code	Initial response	Choke press (psi)	Shoe press (psi)	Addl gain (bbl)
C18	CR1	Uncontrolled	Uncontrolled	Uncontrolled
	CR2	Uncontrolled	Uncontrolled	Uncontrolled
	CR3	1471	11040	5.6
	CR4	15	10495	7.6

The results of the simulations of all the CRs on Well Z, high k kick scenarios are tabulated in Table 6.11, which confirms the results observed from the Well X simulations. For the severe kick scenarios, the Incr P_c to 80% of MAASP, CR2, was not effective. These cases are shown by "Uncntrl" in the table. The Rapid P_c Incr method, CR3, stopped all the kicks and generally had the lowest choke and shoe pressure, as well as the smallest additional gain. The Stepwise P_c Incr method, CR1, was slower and generally allowed additional gain into the well before it stopped the kicks. The Stepwise Q_{in} Incr, CR4, was not functional for Well Z due to insignificant friction in such a large wellbore.

Table 6.11: Well Z, applications of the all CRs on high k kick scenarios

High k			Choke press when kick stopped (psi)				Addl gain until influx stopped (bbl)			
Init gain	Circ UB	Code	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4
2 bbl	0.1 ppge	C37	66	66	46		-0.1	-0.1	0.0	
	0.5 ppge	C38	150	140	146		0.8	0.1	0.6	
	1.2 ppge	C39	326	Uncntrl	307		5.5	Uncntrl	2.1	
20 bbl	0.1 ppge	C40	100	115	103		0.7	0.5	1.7	
	0.5 ppge	C41	226	Uncntrl	200		9.2	Uncntrl	3.7	
	1.2 ppge	C42	451	Uncntrl	374		39	Uncntrl	8.2	

The Stepwise Q_{in} Incr was also investigated for less severe Well Z kick scenarios. Fig. 6.15 illustrates an application of the Stepwise Q_{in} Incr method to a 2 bbl kick from the HP zone of the Well Z (at 4500 ft) with high permeability and a formation pressure that provides a Circ UB of 0.5 ppge. Since the BHA and open hole clearance are large for Well Z, a significant increase in P_{AF} cannot be achieved, and the ECD is practically the same as ESD. After taking 2 bbl of kick, it may be seen that ramping up the pump rate increases the Q_{out}, while the BHP continues to drop. Consequently, the pit gain increases. This response was not successful for any of the Well Z kick scenarios, and therefore, no results are shown in Table 6.11.

6.5.3.1 Summary of the Best Circulating Responses

Based on the results of simulating the application of all CRs on high k kick cases, shown in the previous section and the more comprehensive data in Appendix C, two initial CRs have favorable applications, CR3 and CR4. The Stepwise P_c Incr, CR1 is a less complex alternative to CR3 but is slower and less effective.

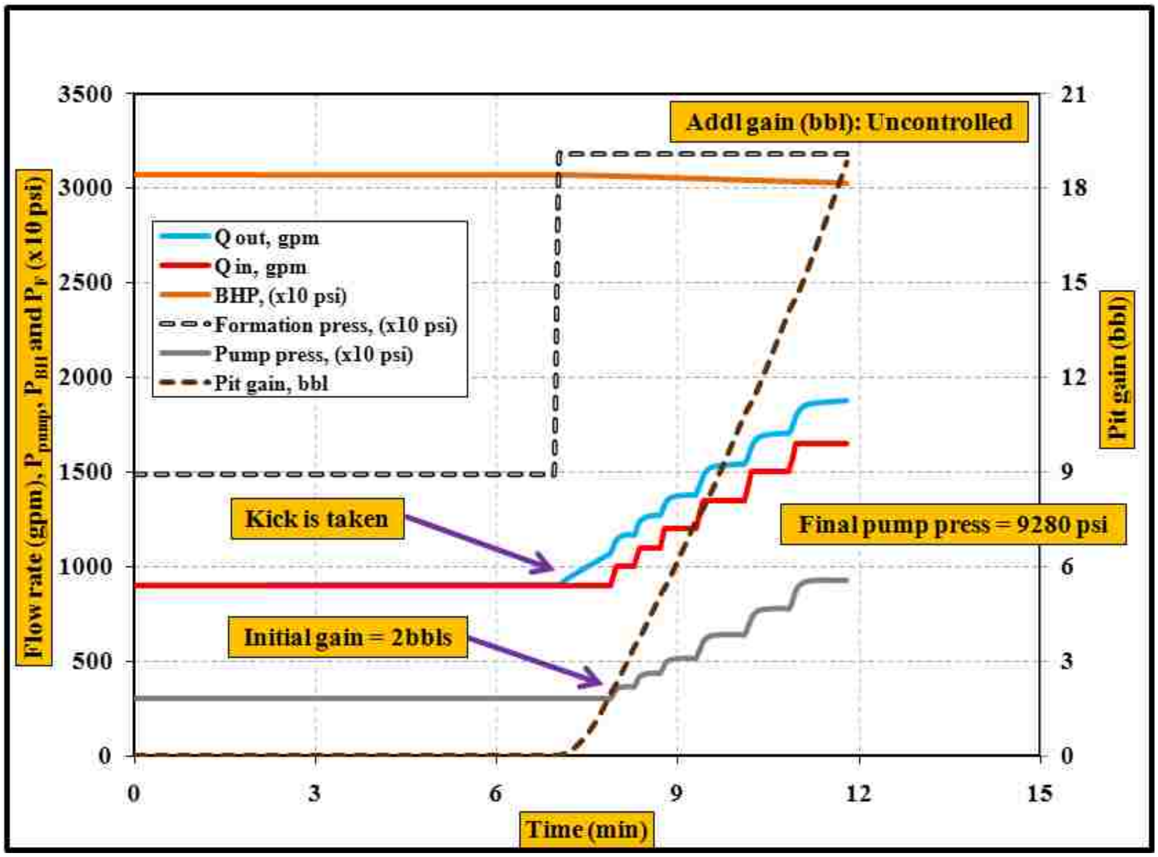


Fig. 6.15: Well Z, application of Stepwise Q_{in} Incr on 2 bbl kick / high k / 0.5 ppge Circ UB

The Rapid P_c Incr method, CR3, stopped all the kicks and generally allowed minimal additional kick into the well. The Stepwise Q_{in} Incr method, CR4, was successful on low volume kicks in the Well X slimhole applications and imposed the least pressure at the shoe. Nevertheless, the application of CR4 has limitations, and hence requires careful pre-planning. No major differences were observed between the low k cases, compared to the high k cases in terms of best identified CRs. The pressures at the shoe and the choke, as well as additional gain, were comparatively lower for the low k cases, due to lower well deliverability. More simulation plots and tables confirming the usefulness of the CR3 and CR4 initial circulating responses can be seen in Appendix C.

6.5.3.2 Advantages of the Best Circulating Responses

There are several advantages in applying the CRs and specifically, the Rapid P_c Incr method, CR3. The most important are the lower choke pressure and pressure applied to the casing shoe as compared to the best NCR; the SI response, NCR1. For a SI response, the choke pressure to stop a kick is always higher, because it must to be increased to offset the loss of ECD. This fact is not significant in the larger wellbore of Well Z. Additionally, CR3 is designd to be a rapid procedure. Therefore, its application in the simulations was relatively fast and effective and did not allow the well to be underbalanced for a long period. Consequently, this procedure generally resulted in a lower additional gain compared to the SI response.

Application of the Stepwise Q_{in} Incr response, CR4, on 2 bbl kicks in Well X also resulted in relatively rapid control. It is also used ECD rather than choke pressure to increase BHP. Accordingly, CR4 resulted in the least shoe pressure among all initial responses for all of the kick scenarios studied. Therefore, it can potentially minimize the risk of lost returns at casing shoe. Moreover, CR4 inherently had minimum choke pressure. The advantages mentioned for CR3 and CR4 versus NCR1 can be observed by comparing Tables 6.8 and 6.9 which display the results of the applications of the CRs to 2 and 20 bbl kicks with Table 6.6, which included the application of NCR1 to the same respective kick scenarios.

Another benefit in applying CR3 or CR4 lies in their ability to proceed to the kick control and circulation operation directly, after stopping the kick. Therefore, pump shut downs and start ups, a routine part of a SI response and subsequent circulation, are unnecessary. Consequently, the application of CR3 or CR4 reduces the NPT and imposes less BHP fluctuations compared to a SI response.

6.5.3.3 Limitations or Disadvantages of the Best Circulating Responses

There are common disadvantages or limitations to the application of the best circulating responses of CR3 and CR4. The most important limitation is that their application requires accurate Q_{out} metering for comparing Q_{out} with Q_{in}. Also, the application of CR3 and CR4 imposes ECD throughout the response. Therefore, there is a higher risk of lost returns, especially for deep and slim wellbores such as Well X, if the HP zone is above a weak zone[91] (for example, drilling in lower, depleted sands in Fig. 4.2). For Well X cases studied in this research, where the HP zone is exactly on bottom while the weak zone is at shoe, the BHP for CR3 is generally higher than for the SI response, NCR1, which confirms this concern (see BHP 10 minutes after the kick stoppage in Appendix C for respective cases).

There is no direct application to confirm kick stoppage for these methods. Therefore, an interpretation of Q_{out} is required. This can create different complications pertinent to each response. For the CR3 method applied to low rate kicks (low k) or large gains, the interpretation of Q_{out} can be difficult, as explained in Section 6.4. However, the method developed to confirm kick stoppage worked satisfactorily in the CR3 simulations. Nevertheless, its practicality should be explored in real field situations or full-scale laboratory well experiments. For the CR4 method however, no practical way was found to confirm the kick stoppage for large gains in Well X although BHP data confirmed the kick stoppage in those simulations where formation pressure is known.

There are limitations specific to Rapid P_c Incr method, CR3. Appendix C shows that the effective application of CR3 to all Well X and Z kick scenarios took an average of 2 to 3 minutes. Slower application of this response causes more gas influx and expansion in the annulus, which results in the interpretation of Q_{out} being more difficult. Therefore, it should be applied as fast as is practical, which may require automated choke operation. Moreover, the application of choke pressure to match Q_{out} with Q_{in} can create and mask lost returns[91].

There are other limitations specific to the Stepwise Q_{in} Incr method, CR4. For large holes like Well Z, it was seen that this response was not functional at all, due to insignificant P_{AF} in the annulus. Therefore, the application of CR4 only accelerates the gas expansion in the annulus, which may rapidly develop into a surface blowout. Additionally, the rig equipment may not have the capability required for CR4. These limitations may include the pressure rating of the pump and surface piping, the maximum pump rate, and the maximum operational limits of the mud-gas separator.

6.5.4 The Results of the Best Alternative Initial Responses

Four out of the nine initial responses evaluated were identified with relative advantages. These responses are: SI (NCR1) and MPD pump SD W/CFC and SI (NCR2) from non-circulating responses, and Rapid P_c Incr (CR3) and Stepwise Q_{in} Incr (CR4) from circulating responses. The rest of the studied initial responses show very specific and limited applications at best and consequently, are not considered generally applicable. The application of these best responses to the high permeability kick scenarios of Well X are tabulated in Table 6.12.

Table 6.12: Well X, application of the best initial responses on high k kick scenarios

High k		Press[1] @ shoe when kick stopped (psi)				Addl gain until influx stopped (bbl)			
Init gain	Circ UB	NCR1	NCR2	CR3	CR4	NCR1	NCR2	CR3	CR4
2 bbl	0.1 ppge	10321	10665	10081	10041	3.2	13.6	0.3	0.3
	0.5 ppge	10665	10827	10405	10241	5.0	42.3	1.7	2.4
	1.2 ppge	11223	11393	10952	10606	5.9	67.2	3.4	4.8
20 bbl	0.1 ppge	10400	10604	10132	9918	5.1	71.2	2.7	4.5
	0.5 ppge	10753	10932	10458	10147	7.9	100.6	4.2	4.1
	1.2 ppge	11316	Incmp[2]	11040	10495	7.1	132.7	5.6	7.6

[1]Pressure data in red when greater than shoe fracture pressure

[2]Incmp: Incomplete data due to the software crashing

The application of the MPD pump SD method of NCR2 is only recommended when the evidence of a kick is not conclusive. The largest additional gain and highest pressure applied to shoe results from using NCR2, when it is conclusive that a kick has been taken. Therefore, this response is only good for low rate or uncertain kicks. The SI response is simple, effective, and may be applied without specialized equipment. Neither NCR1 nor NCR2 require accurate Q_{out} metering. However, if a weak zone is above the kick zone, like the Well X and Z cases in this research, these increase a risk of lost returns at the shoe. Table 6.12 shows that the NCR response causes higher pressure at the shoe and on the average, larger additional gains compared to CRs. Consequently, the application of NCR1 and NCR2 require a careful consideration of the well design, that provides an appropriate kick margin. The NCRs also generally increase NPT and BHP fluctuations.

The rapidly increasing choke pressure method, CR3, stopped kicks and showed advantages in lowering choke and shoe pressure, as well as minimizing additional gain. Therefore, this response is advantageous when there are constraints in terms of well design margins. However, it requires accurate Q_{out} metering, is most practical when using an automated drilling choke, and requires a special interpretation of Q_{out} versus Q_{in} for common size kicks.

The stepwise increasing Q_{in} method, CR4, showed the expected potential to minimize the pressure applied to the shoe. However, it cannot be a standard response due to several critical limitations. These include well geometry providing significant annulus friction pressure losses, surface equipment pressure ratings, and difficulty in interpreting kick stoppage. The application of CR4 also requires accurate Q_{out} metering.

An additional advantage of CR3 and CR4 responses is that they usually tend to reduce NPT and reduce BHP fluctuations.

6.6 Initial Response Plan for kicks Taken during the CBHP Method of MPD Operations

The most applicable initial responses identified herein can be appropriate if conditions and constraints pertinent to their successful application are known and planned. Significant considerations are an availability of accurate Q_{out} metering, the location of weak zones relative to a kick zone, the hole size and its implications for the practicality of a response, and the well design and surface equipment operational limits. These conditions should be considered and collectively satisfied for a practical response. Unfortunately, these conditions vary case by case, and hence, a single initial response that was generally the best was not realized. Yet four initial responses were identified with different advantages and limitations. Therefore, a general guideline was deemed necessary to help choose an initial response that can successfully stop an influx and minimize any associated risks. Careful planning is required in order to provide the conditions and equipment to ensure that a particular response is the best for a given set of well requirements.

Fig. 6.16 summarizes the two key considerations for selecting an initial response into a graphical flow chart. The Stepwise Q_{in} Incr method, CR4, is not considered a standard response due to its limitations but can be an alternative to the Rapid Pc Incr, CR3, response. It is not shown in the flow chart. If an increasing flow rate response, including the necessary equipment, has been designed for successful application, then it may replace the Rapid P_c Incr method in the flow.

A specific consideration when applying the flow chart occurs when accurate Q_{out} metering is available, but an automated drilling choke is not. When an automated drilling choke is not available, manual application of Rapid P_c Incr method, CR3, should be practiced by rig personnel prior to drilling the relevant hole interval, in order to assess its practicality. This approach has not been investigated, and its limitations are not known. A more detailed decision tree for well control operations in the CBHP method of MPD has been developed by the LSU MPD research team. That decision tree, which considers well design in choosing a best initial response is not the focus of this research and is therefore not documented herein.

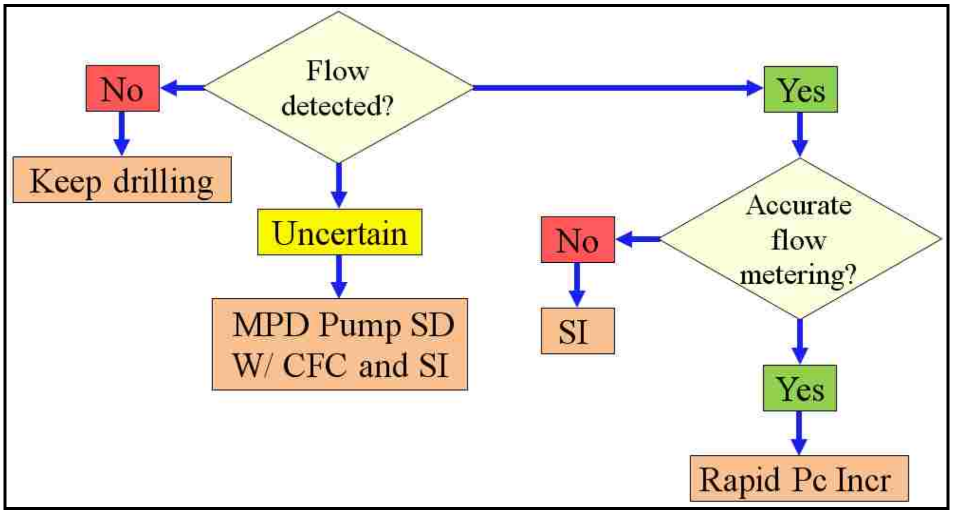


Fig. 6.16: Plan of selecting an initial response to kicks taken during CBHP method of MPD

7. CONCLUSIONS AND RECOMMENDATIONS

7.1 Summary

MPD is a set of new equipment and techniques which aims to reduce problems associated with and the cost of a drilling operation. MPD technology demonstrates a unique application in environments with narrow drilling margins where the drilling-related hazards are more pronounced. The CBHP method, as a variant of MPD, is where pressure at a certain downhole zone is maintained at a constant. A statically underbalanced mud weight is typically used. The downhole pressure is held almost constant at a small overbalance relative to the formation pressure by application of ECD and/or back pressure within a closed annulus. This is mainly to reduce hole problems and may also increase the ROP. In such a drilling environment with restricted kick margins, proper preparation for responding to kicks is important.

The initial response to a kick is an immediate action taken to stop the formation fluid flow into the well. A SI response is the standard initial response to kicks taken in conventional drilling. In the closed annulus of the CBHP method however, there are alternative initial responses to stop an influx. The objective of this research was to identify and evaluate the best initial response to kicks as a basis for reliable well control procedures during MPD operations.

Dynaflodrill^{TM}, a multi-phase transient simulator, was used to study the application of the initial responses to kicks after a satisfactory validation of the software was performed. Gas kicks in water-based mud were selected as the most troublesome kick scenarios for a conservative approach. Kicks taken while drilling into the high pressure (HP) zone of two representative wells: the 6” hole interval of Well X, and the 17.5” hole interval of Well Z, were simulated. Initial pit gains of 2 bbl and 20 bbl were used to represent accurate and conventional kick detection limits for a sensitivity evaluation of a response to initial kick volume. Additionally, two different permeabilities and three different formation pore pressures were selected to provide a broad range of kick severities. Having the casing shoe above the HP zones in both wells, as a typical weak zone in the annulus, allowed an investigation of potential risks imposed on the shoe, while each response focused on stopping a kick. Other criteria for evaluation of the initial responses included the ability to stop an influx while minimizing risks to surface equipment and the ability to minimize additional gains allowed into the well. These criteria helped to identify the most effective responses that caused the least risks.

Nine initial responses to kicks were defined in two categories of responses: non-circulating responses (NCRs) and circulating responses (CRs), based on the mechanism each used to stop a kick. The NCRs included: Shut In (SI), MPD pump shut-down (SD) w/ choked flow check (CFC) and SI, MPD pump SD and SI, Automated MPD pump SD w/ CFC and SI, and Automated MPD pump SD and SI. The CRs, which required accurate flow rate-out (Q_{out}) metering to be applicable, were: Stepwise casing pressure (P_c) Increase, Increase P_c to 80% of MAASP, Rapid P_c Increase, and Stepwise Q_{in} Increase.

7.2 Conclusions

Four initial responses were identified as most applicable. Consequently, an initial response plan was developed, which was based on advantages, practicality, and the conditions required for these responses to be effective. The best initial responses with their associated advantages and limitations follow:

1. **Shut-in (SI):** SI is the most generally applicable response. The specific SI response investigated in this research included shutting down the mud pump followed by closing the choke as rapidly as possible. The advantages of this response are that:

- It stopped all the simulated kicks successfully.
- It is a very simple operational procedure, well known to the industry.
- It can be completed quickly, often resulting in minimal additional gain.

- It allows determining the pressure required for the kick control operation with a simple interpretation of the shut-in casing pressure versus time.
- It does not require special equipment.
- It may be implemented using a rig BOP and choke for containment of higher surface pressure.
- It is the most apt response if the surface equipment fails[95] or if the appropriate conduct for the well control procedure is uncertain.
- It can minimize risk of lost returns at TD or any weak zones below the kick zone[91].

The limitations and disadvantages associated with SI response are that:

- It can increase the risk of lost returns at casing shoe or any other weak points above the kick zone in the annulus.
- It requires pump start ups and shut downs that potentially increase bottomhole pressure fluctuations and usually add to the NPT.
- Due to gas migration, the choke and therefore annulus pressures keep increasing with time after a gas kick is taken in a water-based fluid. This carries a potential risk to well and surface equipment.
- Due to the nature of the hard shut-in associated with this response, extra pressure may be trapped in the well.

2. **MPD pump SD W/ CFC and SI:** This NCR has limited, but useful applications. It includes a MPD stepwise pump SD schedule, which ends by holding the choke pressure constant for a short period as a "choked flow check or CFC," followed by shutting in the well. If the formation is flowing, then the choke pressure can only be kept constant during the CFC by bleeding pressure through the choke. A choke pressure buildup above the scheduled choke

pressure when the well is shut in after bleeding will also confirm the kick. The main advantages with this response are:

- It allows an opportunity for a flow check for uncertain or low rate kicks. Therefore, it can be used as a precaution or on connections for a flow check.
- Like the SI response, it can minimize risk of lost returns at TD or at any weak zones below the kick zone.
- Like the SI response, it determines the pressure required for the kick control operation.

There are limitations and disadvantages associated with this response are:

- Like the SI response, it can increase the risk of lost returns at casing shoe or any other weak points above the kick zone in the annulus.
- It can result in very large gains that seriously complicate the well control operation if applied to a known or high rate kick.

3. **Rapid P_c Increase:** This is the most applicable of the circulating responses. This response, which was applied manually during the simulations, is intended to represent a proprietary automated response. At a constant mud pumping rate, the choke is closed rapidly until Q_{out} approaches Q_{in}, then smaller manipulations are attempted to match Q_{out} to Q_{in}. The main advantages with this response are:

- It was effective over all kick scenarios.
- It generally resulted in a lower choke pressure and pressure at the shoe than both non-circulating responses and than the other circulating responses that used increased casing pressure. Therefore, it has a lower risk of lost returns at shoe than those responses, including SI.
- It generally allowed less additional gain into the well.

- Conceptually, it is a relatively simple operational procedure.
- No pump shut downs or start ups are required. Therefore, it imposes minimal bottomhole pressure fluctuations.
- After successful application of this initial response, it can continue as a kick control operation. Hence, it reduces non-productive time (NPT) versus a SI response.

There are limitations and disadvantages associated with this response, which are:

- This response requires accurate Q_{out} metering in order to assess whether formation flow has been stopped.
- Even with accurate Q_{out} metering, it requires an interpretation to confirm kick stoppage. The presumed method of matching Q_{out} to Q_{in} may be difficult, especially for low rate kicks or large gas influxes. A new approach, described herein, of bumping the choke twice to evaluate the trend of Q_{out} versus time showed practical advantages for this purpose. This approach, however, was not quantified in this research.
- It was effective when applied rather quickly, within 2 to 3 minutes. Therefore, the real application of this response requires an automated choke system or personnel who have successfully practiced applying it.
- If the wellbore is not intact, the matching of Q_{out} to Q_{in} by control of choke pressure can mask lost returns[91].
- It increases the chance of lost returns at TD or into any weak zones below the kick zone[91].

4. **Stepwise Q_{in} Increase:** This CR has special, but limited applications. At a constant choke pressure, the pump rate is increased in stepwise fashion to raise the Q_{in}, and raise the ECD in the well, to match with Q_{out}. The main advantages with this response, include:

- This response applied the minimum pressure at shoe and hence it can reduce the risk of lost returns at casing shoe.

There are serious limitations and disadvantages associated with this response, including:

- It does not apply to wells with low annular frictional pressure losses, e.g. large hole sizes.
- It requires accurate Q_{out} metering.
- It requires interpretation to confirm kick stoppage. This interpretation was not possible for large gas kicks, as gas expansion in the annulus is rapidly accelerated by the increased pumping rate. This combination of interpretation difficulty and increased gas expansion can lead quickly to having a surface blowout.
- The Q_{in} and/or pump pressure required to stop a kick may be higher than possible with the available pumps. The resulting high surface flow rates can also exceed the mud-gas separator capabilities.
- This response causes the greatest likelihood of lost returns if there are any weak zones below the kick zone[91].

Based on a large number of simulations of initial responses to a variety of kicks and different sensitivities, a single best initial response to all kind of kicks during the CBHP method of MPD operations was not identified. Multiple factors impose limitations on which response will be most successful, including accurate Q_{out} metering, well design aspects, location of a weak zone relative to the kick zone, hole size, and surface equipment ratings. Therefore, proper planning and implementation are necessary for an effective initial response.

7.3 Recommendations

Based on the results of this research, the following are recommendations for future work.

1. The choked flow check was simulated using a choke pressure input which corresponded to automated application. It should also be attempted using a manual choke to evaluate its practicality (done by Jose Chirinos on actual well).

2. The realistic feasibility of bumping the choke to confirm the kick stoppage, during the Rapid P_c Increase method, should be checked on field or full-scale test wells to confirm the simulation results. A quantitative approach to examining the trend of flow rate out after a gas kick is stopped may be feasible by means of computer aided programs. In that case, one proposal may be to develop a model based on specific well geometry, reservoir conditions and kick volume to predict a steady-state flow rate out trend due to gas expansion in the annulus. This trend could actually be compared to the flow rate-out response during the choke bumping steps discussed in this research.

3. The Rapid P_c Increase response was simulated in DFD using the choke opening; however, the results showed a faster choke response, possibly due to the simulator model. A manual application of this response in a full-scale test facility might evaluate how fast the task can be completed based on real well response. This would be valuable when an automated choke is not available.

4. Since the simulation of only intact wellbores was possible in DFD, the results of best initial responses should be investigated for cases where borehole fracture occurred to evaluate their sensitivity to a broken wellbore.

5. The demonstration of the best initial responses should be conducted at a full-scale test facility to examine the practicality of the responses.

6. A method should be developed to estimate the kick zone pore pressure during the application of circulating responses.

7. A kick circulation study should be conducted as a complement to this study. It should include the application of any current methods, such as the 'drillers' method, after the successful application of an initial response to a kick. The study should aim to evaluate whether the best initial responses would pose any unidentified risks to the well, during or after the circulation work.

8. It would also be valuable to study the effect of equipment problems, such as drillstring or choke washouts, plugged bit or choke on kick responses and circulation.

9. An evaluation of the proposed "Implied Pit Gain[103]" method as a basis for identifying lost returns and/or underground blowouts following a kick during MPD operations is recommended. Simulation-based study to evaluate this possibility should be conducted.

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APPENDIX A: WELL X SIMULATIONS INPUT DATA

Case Description

Project: Alternative initial responses to gas kicks during MPD operations
Data description: Simulation inputs for no kick case (Base) with high permeability
Well: X
Well section: 6 in.
Software: Drillbench (Dynaflodrill module)
Company: SPT (Scandpower Petroleum Technology) Group
Creator: Majid Davoudi
Date: 01-Aug-2009

Survey

Md	Inclination	Azimuth	Vertical depth
[ft]	[deg]	[deg]	[ft]
0	0.0	0.0	0.00
10074	26.4	48.8	10005.88
10349	27.7	49.2	10251.08
10623	30.9	50.4	10490.69
10895	34.4	50	10719.59
11165	37	49.3	10938.2
11435	38	49.4	11152.41
11707	39.4	49.4	11364.77
11982	40.4	49.8	11575.74
12254	40.8	50	11782.57
12531	40.6	50.4	11992.47
12805	40.2	50.6	12201.02
13175	41	50.9	12481.86
13451	41	50.9	12690.06
13727	41.5	50.8	12897.89
14002	40.8	50.7	13104.65
14233	40.8	51.3	13279.25
14503	39.9	51.3	13484.61
14772	40.4	51.4	13690.42
14862	40.1	51.5	13759.11
14951	40.1	51.7	13827.19
15042	40.1	51.7	13896.8
15132	40.2	52.1	13965.59
15170	40.2	52.2	13994.62
15193	41.6	54.4	14012.01
15200	41.6	54.4	14017.24
15243	41.6	54.4	14049.37
15300	41.1	55.3	14092.16
15400	40.1	56.8	14168.12
15443	39.6	57.4	14201.13

15500	40.7	59	14244.7
15600	42.5	61.5	14319.49
15700	44.4	63.9	14392.08
15750.73	45.4	65.1	14428.01
15800	44.9	63.4	14462.76
15900	44	60.1	14534.12
16000	43.3	56.7	14606.49
16021.3	43.1	55.9	14622.02
16100	43.1	55.9	14679.49
16200	43.1	55.9	14752.5
16300	43.1	55.9	14825.52
16400	43.1	55.9	14898.54
16500	43.1	55.9	14971.55
16580.04	43.1	55.9	15029.99
16600	43.1	55.9	15044.57
16700	43.1	55.9	15117.58
16780.04	43.1	55.9	15176.03
16800	43.4	55.9	15190.56
16900	44.9	55.9	15262.31
16982.3	46.1	55.9	15319.98
17000	46.1	55.9	15332.25
17100	46.1	55.9	15401.55
17200	46.1	55.9	15470.85
17300	46.1	55.9	15540.16
17400	46.1	55.9	15609.46
17500	46.1	55.9	15678.76
17600	46.1	55.9	15748.06
17674.95	46.1	55.9	15800.01

Wellbore Geometry

Name	Hanger depth	Setting depth	Inner diameter	Outer diameter
	[ft]	[ft]	[in]	[in]
7" T95 32.0 lbs/ft	0.00	15150.00	6.094	7.000

Target depth (ft): 17700.00
Open hole length (ft): 1110.00
Open hole diameter (in): 6.00

String

Component	Type	Section length	Inner diameter	Outer diameter
		[ft]	[in]	[in]
DC 4 3/4" NC 35-37	DrillCollar	250.00	2.500	4.750
HWDP 3 1/2" NC38(3 1/2 IF)	Drillpipe	450.00	2.063	3.500
dp 3 1/2" S135 15.50 lb/ft	Drillpipe	15560.00	2.602	3.500

Average stand length (ft): 95.00
Bit outer diameter (in): 6.00
Flow area (sq in): 0.37
Number of bit nozzles: 4
Nozzles diameter (1/32 in): 11

Choke

Inner diameter (in): 3.00
Closure time (min): 0.50
Choke control: Opening
Working pressure (psi): 14.70

Mud

Type: Water Based Mud (WBM)
Base oil density (ppg): 7.3022
Water density (ppg): 8.3454
Solids density (ppg): 35.0507
Density (ppg): 13.20
Reference temperature (deg F): 90.00
Fluid type: Liquid
Oil water ratio: 0 / 100
Rheology type: Non-Newtonian; Fann tables
PVT model: Black oil

Fann Reading	
Shear rate	**Shear stress**
[rpm]	**[lbf/100ft2]**
600	47
300	26
200	17
100	11
6	3
3	2

Reservoir

Name	Top	Bottom	Type	Press	Temp	Porosity	Perm	Fluid	Flow model
	[ft]	[ft]		[psi]	[degF]	[0-1]	[mD]		
Form1	15150	16265	Matrix	8723	145.00	0.27	1	Gas	Reservoir model
HP Sand	16265	16401	Matrix	10544	155.81	0.27	500	Gas	Reservoir model

Hole cleaning criterion: Max concentration
Cuttings density (ppg): 0.1
Max concentration: 0.04

Water	
Density (ppg)	8.4289
Compressibility (1/psi)	7.58 E-08
Volume factor	1.00
Viscosity (cp)	1.00
Oil	
Density (ppg)	7.4691
Compressibility (1/psi)	1.38 E-06
Volume factor	1.10
Viscosity (cp)	2.00
Gas	
Density (SG)	0.65
N2	0.00
CO2	0.00
Hydrocarbon	1.00
H2S	0.00

Temperature

Drillstring Temperature	
Depth [ft]	**[def F]**
0.00	85.00
17700.00	170.00
Annulus Temperature	
Depth [ft]	**[def F]**
0.00	90.00
17700.00	170.00

Optional Input

Open hole roughness: 0.099996
Steel roughness: 0.0004
Pressure loss model: Semi-empirical
Gas density model: Hall-Yarborough
Friction factor model: Dodge-Metzner
Rheology model: Robertson-Stiff

End of data.

APPENDIX B: WELL Z SIMULATIONS INPUT DATA

Case Description

Project: Alternative initial responses to gas kicks during MPD operations
Data description: Simulation inputs for no kick case (Base) with high permeability
Well: Z
Well section: 17.50 in.
Software: Drillbench (Dynaflodrill module)
Company: SPT (Scandpower Petroleum Technology) Group
Creator: Majid Davoudi
Date: 01-Aug-2009

Survey

Md	Inclination	Azimuth	Vertical depth
[ft]	[deg]	[deg]	[ft]
0.00	0.0	0.0	0.00
4756.00	0.0	0.0	4756.00

Wellbore Geometry

Name	Hanger depth	Setting depth	Inner diameter	Outer diameter
	[ft]	[ft]	[in]	[in]
20" C90 133 lbs/ft	0.00	3280.00	18.728	20.000

Target depth (ft): 4756.00
Open hole length (ft): 1215.00
Open hole diameter (in): 17.50

String

Component	Type	Section length	Inner diameter	Outer diameter
		[ft]	[in]	[in]
DC 9"	DrillCollar	390.00	3.000	9.000
HWDP 5"	Drillpipe	180.00	3.000	5.000
DP 5"	Drillpipe	3925.00	4.276	5.000

Average stand length (ft): 95.00
Bit outer diameter (in): 17.50
Flow area (sq in): 0.75
Number of bit nozzles: 3
Nozzles diameter (1/32 in): 18

Choke

Inner diameter (in): 3.00
Closure time (min): 0.50
Choke control: Pressure
Working pressure (psi): 14.70

Mud

Type: Water Based Mud (WBM)
Base oil density (ppg): 7.3022
Water density (ppg): 8.3454
Solids density (ppg): 35.0507
Density (ppg): 13.10
Reference temperature (deg F): 90.00
Fluid type: Liquid
Oil water ratio: 0 / 100
Rheology type: Non-Newtonian; Fann tables
PVT model: Black oil

Fann Reading	
Shear rate	**Shear stress**
[rpm]	**[lbf/100ft2]**
600	47
300	26
200	17
100	11
6	3
3	2

Reservoir

Name	Top	Bottom	Type	Press	Temp	Porosity	Perm	Fluid	Flow model
	[ft]	[ft]		[psi]	[deg F]	[0-1]	[mD]		
Form1	3280	4500	Matrix	1491	98.00	0.3	1	Gas	Reservoir model
HP Sand	4500	4756	Matrix	3042	124.00	0.3	500	Gas	Reservoir model

Hole cleaning criterion: Max concentration
Cuttings density (ppg): 0.1
Max concentration: 0.04

Water	
Density (ppg)	8.4289
Compressibility (1/psi)	7.58 E-08
Volume factor	1.00
Viscosity (cp)	1.00
Oil	
Density (ppg)	7.4691
Compressibility (1/psi)	1.38 E-06
Volume factor	1.10
Viscosity (cp)	2.00
Gas	

Density (SG)	0.65
N2	0.00
CO2	0.00
Hydrocarbon	1.00
H2S	0.00

Temperature

Drillstring Temperature	
Depth [ft]	**[def F]**
0.00	85.00
4756.00	130.00
Annulus Temperature	
Depth [ft]	**[def F]**
0.00	90.00
4756.00	130.00

Optional Input

Open hole roughness: 0.099996
Steel roughness: 0.0004
Pressure loss model: Semi-empirical
Gas density model: Hall-Yarborough
Friction factor model: Dodge-Metzner
Rheology model: Robertson-Stiff

End of data.

APPENDIX C:

WELL X AND Z TABLES OF RESULTS AND SIMULATION PLOTS

Content Index

Well X Non-Circ Responses (NCRs[1])

High k			Choke press when kick stopped (psi)					ΔChoke press after 10 min (psi)					Addl gain until influx stopped (bbl)				
Init gain	Circ UB	Code	NCR1	NCR2	NCR3	NCR4	NCR5	NCR1	NCR2	NCR3	NCR4	NCR5	NCR1	NCR2	NCR3	NCR4	NCR5
2 bbl	0.1 ppge	C1	736	989	831	815	697	17	83	33	35	13	3.2	13.6	7.6	6.4	2.1
	0.5 ppge	C2	1095	1842	1606	1372	1166	29	283	226	128	49	5.0	42.3	30.4	16.9	8.3
	1.2 ppge	C3	1656	2844	2470	2072	1796	35	379	316	179	88	5.9	67.2	48.4	25.7	12.8
20 bbl	0.1 ppge	C4	1160	2531	2066	1610	1303	107	408	368	252	164	5.1	71.2	49.0	25.8	12.3
	0.5 ppge	C5	1506	3421	2762	2070	1687	186	459	430	334	266	7.9	100.6	69.3	35.2	17.4
	1.2 ppge	C6	2034	Incmp[2]	3755	2790	2352	185	Incmp	452	356	278	7.1	132.7	92.6	46.0	24.0
Low k			**Choke press when kick stopped (psi)**					**ΔChoke press after 10 min (psi)**					**Addl gain until influx stopped (bbl)**				
Init gain	Circ UB	Code	NCR1	NCR2	NCR3	NCR4	NCR5	NCR1	NCR2	NCR3	NCR4	NCR5	NCR1	NCR2	NCR3	NCR4	NCR5
2 bbl	0.1 ppge	C7	686	680	667	660	651	13	17	16	12	11	1.5	1.6	1.1	0.7	0.4
	0.5 ppge	C8	984	1058	1029	1000	975	10	21	18	13	11	1.4	4.9	3.9	2.2	1.3
	1.2 ppge	C9	1524	1641	1614	1570	1534	10	24	21	13	12	1.6	7.9	6.4	3.7	2.2
20 bbl	0.1 ppge	C10	1199	Incmp	1493	1317	1186	121	Incmp	Incmp	151	118	5.0	32.3	20.2	10.4	5.2
	0.5 ppge	C11	1419	1971	1804	1603	1474	78	278	208	140	90	3.5	29.8	22.1	11.8	6.4
	1.2 ppge	C12	1943	2620	2402	2162	2017	96	339	291	195	122	4.1	36.4	26.7	14.5	8.1

[1]NCR1: SI, NCR2: MPD Pump SD W/CFC & SI, NCR3: MPD Pump SD & SI, NCR4: Auto MPD Pump SD W/CFC & SI, NCR5: Auto MPD Pump SD & SI

[2]Incmp: Incomplete data due to the software crashing

Well X NCRs (Continued)

High k			Press[1] @ shoe when kick stopped (psi)					ΔPress @ shoe after 10 min (psi)					ΔPress on bottom after 10 min (psi)				
Init gain	Circ UB	Code	NCR1	NCR2	NCR3	NCR4	NCR5	NCR1	NCR2	NCR3	NCR4	NCR5	NCR1	NCR2	NCR3	NCR4	NCR5
2 bbl	0.1 ppge	C1	10321	10437	10340	10364	10274	-21	0	-6	-22	2	19	154	56	62	14
	0.5 ppge	C2	10665	10827	10776	10777	10678	-23	158	136	42	-1	59	395	323	231	96
	1.2 ppge	C3	11223	11393	11327	11340	11244	-24	198	197	83	31	85	464	402	303	161
20 bbl	0.1 ppge	C4	10400	10604	10534	10537	10430	41	187	203	116	81	160	488	452	367	230
	0.5 ppge	C5	10753	10932	10855	10870	10779	95	212	235	167	147	261	508	490	439	340
	1.2 ppge	C6	11316	Incmp	11416	11432	11355	84	Incmp	226	157	143	281	Incmp	508	455	378
Low k			**Press @ shoe when kick stopped (psi)**					**ΔPress @ shoe after 10 min (psi)**					**ΔPress on bottom after 10 min (psi)**				
Init gain	**Circ UB**	**Code**	**NCR1**	**NCR2**	**NCR3**	**NCR4**	**NCR5**	**NCR1**	**NCR2**	**NCR3**	**NCR4**	**NCR5**	**NCR1**	**NCR2**	**NCR3**	**NCR4**	**NCR5**
2 bbl	0.1 ppge	C7	10257	10234	10221	10226	10217	3	9	11	7	8	13	17	16	12	12
	0.5 ppge	C8	10571	10588	10569	10573	10553	-1	4	7	1	2	12	26	22	16	14
	1.2 ppge	C9	11116	11114	11115	11116	11112	-5	13	9	2	-3	16	34	30	23	17
20 bbl	0.1 ppge	C10	10359	Incmp	10386	10391	10329	79	Incmp	Incmp	97	85	164	Incmp	Incmp	215	145
	0.5 ppge	C11	10641	10725	10675	10687	10635	47	185	151	92	62	113	335	252	202	124
	1.2 ppge	C12	11178	11257	11210	11225	11173	66	230	213	137	92	136	375	314	254	159

[1]Pressure data in red when greater than shoe fracture pressure

Well X Circ Responses (CRs[1])

High k			Choke press when kick stopped (psi)				ΔChoke press after 10 min (psi)				Addl gain until influx stopped (bbl)			
Init gain	Circ UB	Code	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4
2 bbl	0.1 ppge	C13	130	135	128	15	70	535	24	0	0.1	0.0	0.3	0.3
	0.5 ppge	C14	490	465	455	15	110	205	73	0	2.6	1.0	1.7	2.4
	1.2 ppge	C15	1230	Uncntrl[2]	1037	15	210	Uncntrl	144	35	16.0	Uncntrl	3.4	4.8
20 bbl	0.1 ppge	C16	590	525	526	15	150	145	151	Imprac[3]	5.7	2.0	2.7	4.5
	0.5 ppge	C17	1100	Uncntrl	865	15	190	Uncntrl	139	Imprac	17.9	Uncntrl	4.2	4.1
	1.2 ppge	C18	Uncntrl	Uncntrl	1471	15	Uncntrl	Uncntrl	497	Imprac	Uncntrl	Uncntrl	5.6	7.6
Low k			Choke press when kick stopped (psi)				ΔChoke press after 10 min (psi)				Addl gain until influx stopped (bbl)			
Init gain	Circ UB	Code	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4
2 bbl	0.1 ppge	C19	130	135	116	15	70	535	17	0	-0.1	-0.1	0.0	0.1
	0.5 ppge	C20	430	435	423	15	70	235	104	0	0.2	-0.2	0.2	0.8
	1.2 ppge	C21	980	Uncntrl	941	15	20	Uncntrl	235	0	1.3	Uncntrl	0.4	1.2
20 bbl	0.1 ppge	C22	500	495	484	15	150	175	137	Imprac	1.7	0.1	1.2	4.3
	0.5 ppge	C23	890	Uncntrl	796	15	150	Uncntrl	220	Imprac	5.0	Uncntrl	1.7	4.2
	1.2 ppge	C24	1590	Uncntrl	1315	15	190	Uncntrl	241	Imprac	12.4	Uncntrl	2.5	4.7

[1]CR1: Stepwise Pc Incr, CR2: Incr Pc to 80% MAASP, CR3: Rapid Pc Incr, CR4: Stepwise Qin Incr

[2]Uncntrl: Uncontrolled, unsuccessful response to the respective kick scenario

[3]Imprac: Impractical, incomplete simulations due to the lack of practical certainty that influx is stopped

Well X CRs (Continued)

High k			Press[1] @ shoe when kick stopped (psi)				ΔPress @ shoe after 10 min (psi)				ΔPress on bottom after 10 min (psi)			
Init gain	Circ UB	Code	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4
2 bbl	0.1 ppge	C13	10079	10086	10081	10041	77	552	22	24	90	570	37	47
	0.5 ppge	C14	10401	10413	10405	10241	115	204	53	9	138	237	93	26
	1.2 ppge	C15	10911	Uncntrl	10952	10606	164	Uncntrl	132	49	182	Uncntrl	188	68
20 bbl	0.1 ppge	C16	10103	10126	10132	9918	79	80	65	Imprac	114	145	140	Imprac
	0.5 ppge	C17	10399	Uncntrl	10458	10147	42	Uncntrl	52	Imprac	74	Uncntrl	150	Imprac
	1.2 ppge	C18	Uncntrl	Uncntrl	11040	10495	Uncntrl	Uncntrl	437	Imprac	Uncntrl	Uncntrl	585	Imprac
Low k			Press @ shoe when kick stopped (psi)				ΔPress @ shoe after 10 min (psi)				ΔPress on bottom after 10 min (psi)			
Init gain	Circ UB	Code	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4
2 bbl	0.1 ppge	C19	10066	10067	10063	10030	78	559	12	28	85	572	20	46
	0.5 ppge	C20	10370	10375	10372	10241	82	257	108	5	88	274	118	16
	1.2 ppge	C21	10904	Uncntrl	10893	10616	27	Uncntrl	239	9	31	Uncntrl	244	27
20 bbl	0.1 ppge	C22	10073	10090	10078	9902	58	110	33	Imprac	79	148	66	Imprac
	0.5 ppge	C23	10379	Uncntrl	10386	10127	93	Uncntrl	159	Imprac	108	Uncntrl	191	Imprac
	1.2 ppge	C24	10917	Uncntrl	10902	10518	112	Uncntrl	172	Imprac	124	Uncntrl	188	Imprac

[1]Pressure data in red when greater than shoe fracture pressure

Well Z Non-Circ Responses (NCRs[1])

High k			Choke press when kick stopped (psi)					ΔChoke press after 10 min (psi)					Addl gain until influx stopped (bbl)				
Init gain	Circ UB	Code	NCR1	NCR2	NCR3	NCR4	NCR5	NCR1	NCR2	NCR3	NCR4	NCR5	NCR1	NCR2	NCR3	NCR4	NCR5
2 bbl	0.1 ppge	C25	48					25					2.0				
	0.5 ppge	C26	146					69					2.8				
	1.2 ppge	C27	316					80					4.6				
20 bbl	0.1 ppge	C28	117					124					9.0				
	0.5 ppge	C29	223					158					12.0				
	1.2 ppge	C30	417					179					21.7				
Low k			**Choke press when kick stopped (psi)**					**ΔChoke press after 10 min (psi)**					**Addl gain until influx stopped (bbl)**				
Init gain	**Circ UB**	**Code**	**NCR1**	**NCR2**	**NCR3**	**NCR4**	**NCR5**	**NCR1**	**NCR2**	**NCR3**	**NCR4**	**NCR5**	**NCR1**	**NCR2**	**NCR3**	**NCR4**	**NCR5**
2 bbl	0.1 ppge	C31	50					18					0.8				
	0.5 ppge	C32	143					61					1.2				
	1.2 ppge	C33	307					62					1.4				
20 bbl	0.1 ppge	C34	97					167					1.9				
	0.5 ppge	C35	192					195					2.7				
	1.2 ppge	C36	356					169					2.8				

[1]NCR1: SI, all other NCRs do not apply to Well Z due to the lack of ECD to construct the MPD pump SD schedule

Well Z NCRs (Continued)

High k			Press[1] @ shoe when kick stopped (psi)					ΔPress @ shoe after 10 min (psi)					ΔPress on bottom after 10 min (psi)				
Init gain	Circ UB	Code	NCR1	NCR2	NCR3	NCR4	NCR5	NCR1	NCR2	NCR3	NCR4	NCR5	NCR1	NCR2	NCR3	NCR4	NCR5
2 bbl	0.1 ppge	C25	2275					24					24				
	0.5 ppge	C26	2374					68					69				
	1.2 ppge	C27	2544					80					80				
20 bbl	0.1 ppge	C28	2343					121					129				
	0.5 ppge	C29	2450					157					167				
	1.2 ppge	C30	2646					172					192				
Low k			**Press @ shoe when kick stopped (psi)**					**ΔPress @ shoe after 10 min (psi)**					**ΔPress on bottom after 10 min (psi)**				
Init gain	Circ UB	Code	NCR1	NCR2	NCR3	NCR4	NCR5	NCR1	NCR2	NCR3	NCR4	NCR5	NCR1	NCR2	NCR3	NCR4	NCR5
2 bbl	0.1 ppge	C31	2270					18					18				
	0.5 ppge	C32	2369					60					61				
	1.2 ppge	C33	2534					62					63				
20 bbl	0.1 ppge	C34	2280					162					169				
	0.5 ppge	C35	2390					188					198				
	1.2 ppge	C36	2566					161					173				

[1]Pressure data in red when greater than shoe fracture pressure

Well Z Circ Responses (CRs[1])

High k			Choke press when kick stopped (psi)				ΔChoke press after 10 min (psi)				Addl gain until influx stopped (bbl)			
Init gain	Circ UB	Code	CR1	CR2	CR3	CR4[3]	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4
2 bbl	0.1 ppge	C37	66	66	46		134	74	8		-0.1	-0.1	0.0	
	0.5 ppge	C38	150	140	146		50	0	40		0.8	0.1	0.6	
	1.2 ppge	C39	326	Uncntrl	307		74	Uncntrl	111		5.5	Uncntrl	2.1	
20 bbl	0.1 ppge	C40	100	115	103		100	25	37		0.7	0.5	1.7	
	0.5 ppge	C41	226	Uncntrl	200		74	Uncntrl	76		9.2	Uncntrl	3.7	
	1.2 ppge	C42	451	Uncntrl	374		149	Uncntrl	116		39	Uncntrl	8.2	
Low k			Choke press when kick stopped (psi)				ΔChoke press after 10 min (psi)				Addl gain until influx stopped (bbl)			
Init gain	Circ UB	Code	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4
2 bbl	0.1 ppge	C43	66	66	46		134	74	8		-0.2	-0.2	-0.1	
	0.5 ppge	C44	150	140	136		50	0	13		-0.3	-0.4	-0.2	
	1.2 ppge	C45	326	Uncntrl	307		74	Uncntrl	45		-0.3	Uncntrl	-0.3	
20 bbl	0.1 ppge	C46	100	105	88		100	35	65		-1.9	-2.0	-0.6	
	0.5 ppge	C47	190	Uncntrl	187		110	Uncntrl	93		-0.2	Uncntrl	0.4	
	1.2 ppge	C48	351	Uncntrl	346		149	Uncntrl	115		1.2	Uncntrl	0.3	

[1]CR1: Stepwise Pc Incr, CR2: Incr Pc to 80% MAASP, CR3: Rapid Pc Incr, CR4: Stepwise Qin Incr

[2]Uncntrl: Uncontrolled, unsuccessful response to the respective kick scenario

[3]Stepwise Qin Incr: Not functional on Well Z as discussed in Chapter 5

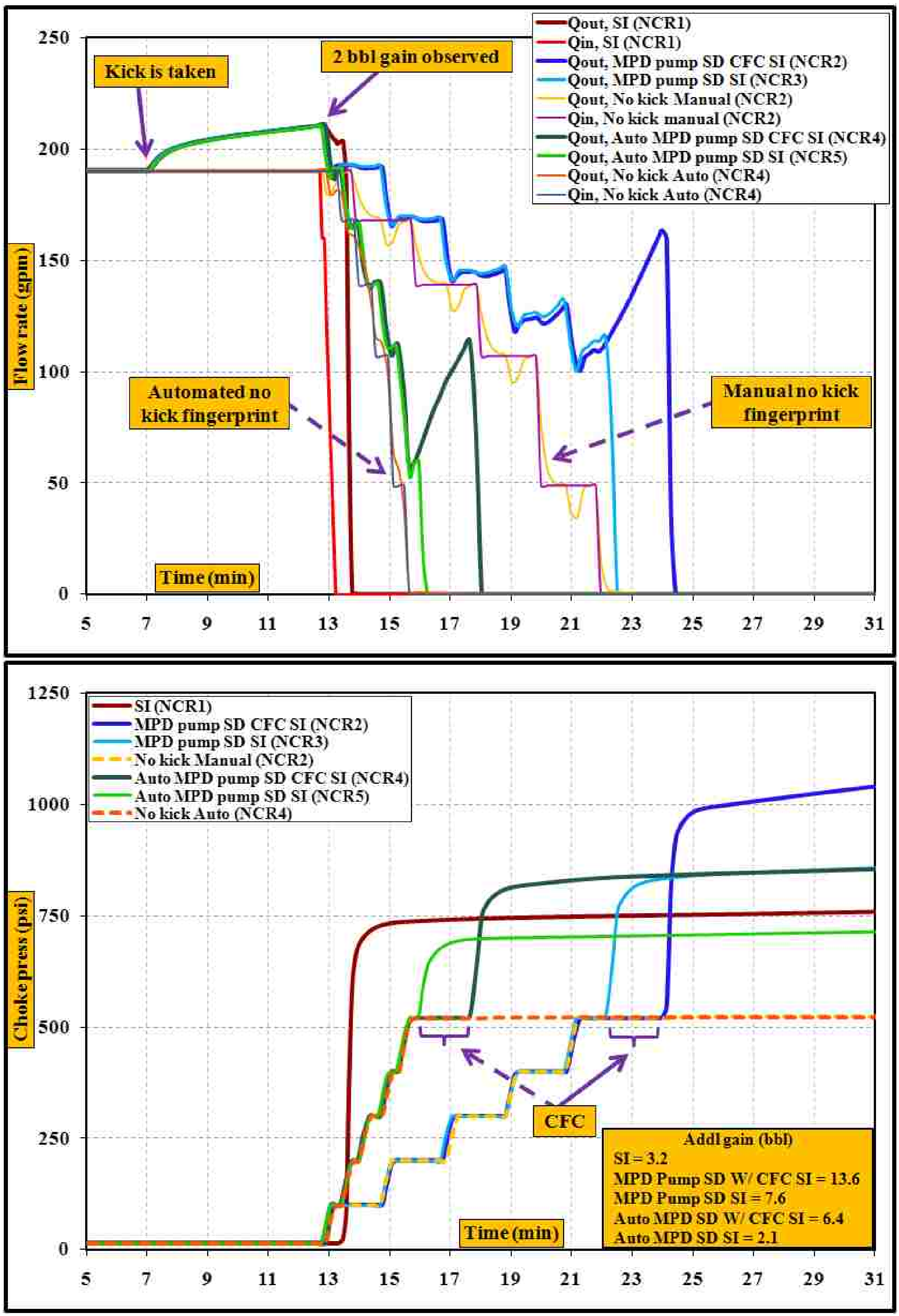
Well Z CRs (Continued)

High k			Press[1] @ shoe when kick stopped (psi)				ΔPress @ shoe after 10 min (psi)				ΔPress on bottom after 10 min (psi)			
Init gain	Circ UB	Code	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4
2 bbl	0.1 ppge	C37	2295	2295	2275		128	68	1		137	77	9	
	0.5 ppge	C38	2379	2369	2375		42	-7	33		52	1	42	
	1.2 ppge	C39	2556	Uncntrl	2537		53	Uncntrl	99		78	Uncntrl	115	
20 bbl	0.1 ppge	C40	2329	2344	2332		50	-27	-19		104	26	38	
	0.5 ppge	C41	2455	Uncntrl	2429		2	Uncntrl	20		79	Uncntrl	81	
	1.2 ppge	C42	2674	Uncntrl	2605		16	Uncntrl	50		151	Uncntrl	125	
Low k			Press @ shoe when kick stopped (psi)				ΔPress @ shoe after 10 min (psi)				ΔPress on bottom after 10 min (psi)			
Init gain	Circ UB	Code	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4	CR1	CR2	CR3	CR4
2 bbl	0.1 ppge	C43	2289	2289	2269		125	64	-2		137	76	8	
	0.5 ppge	C44	2378	2368	2364		40	-9	2		52	2	14	
	1.2 ppge	C45	2555	Uncntrl	2536		64	Uncntrl	35		76	Uncntrl	47	
20 bbl	0.1 ppge	C46	2290	2295	2274		66	-5	27		90	19	50	
	0.5 ppge	C47	2392	Uncntrl	2386		64	Uncntrl	46		97	Uncntrl	77	
	1.2 ppge	C48	2559	Uncntrl	2556		104	Uncntrl	69		142	Uncntrl	108	

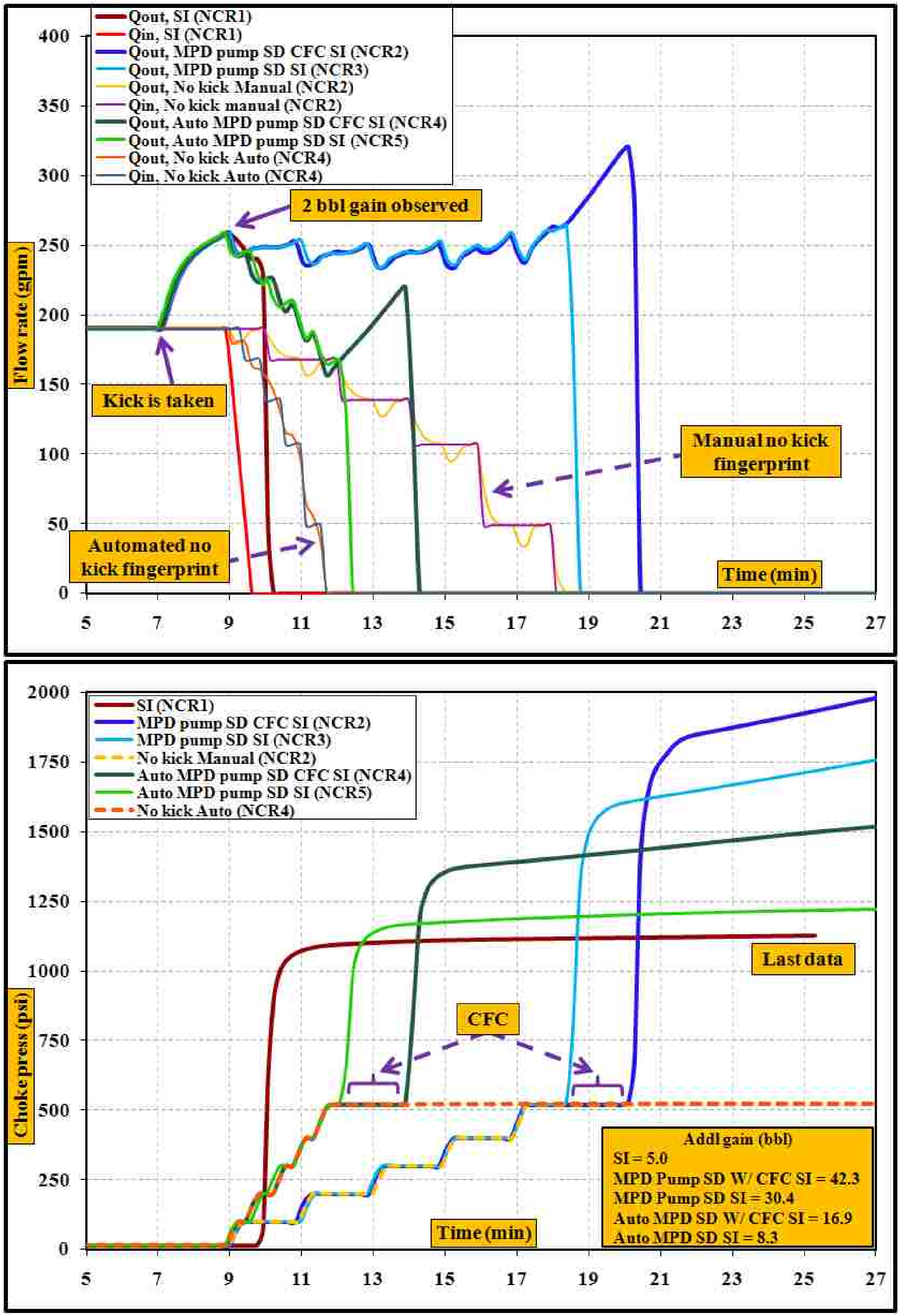
[1]Pressure data in red when greater than shoe fracture pressure

INDEX FOR WELL X SIMULATION PLOTS

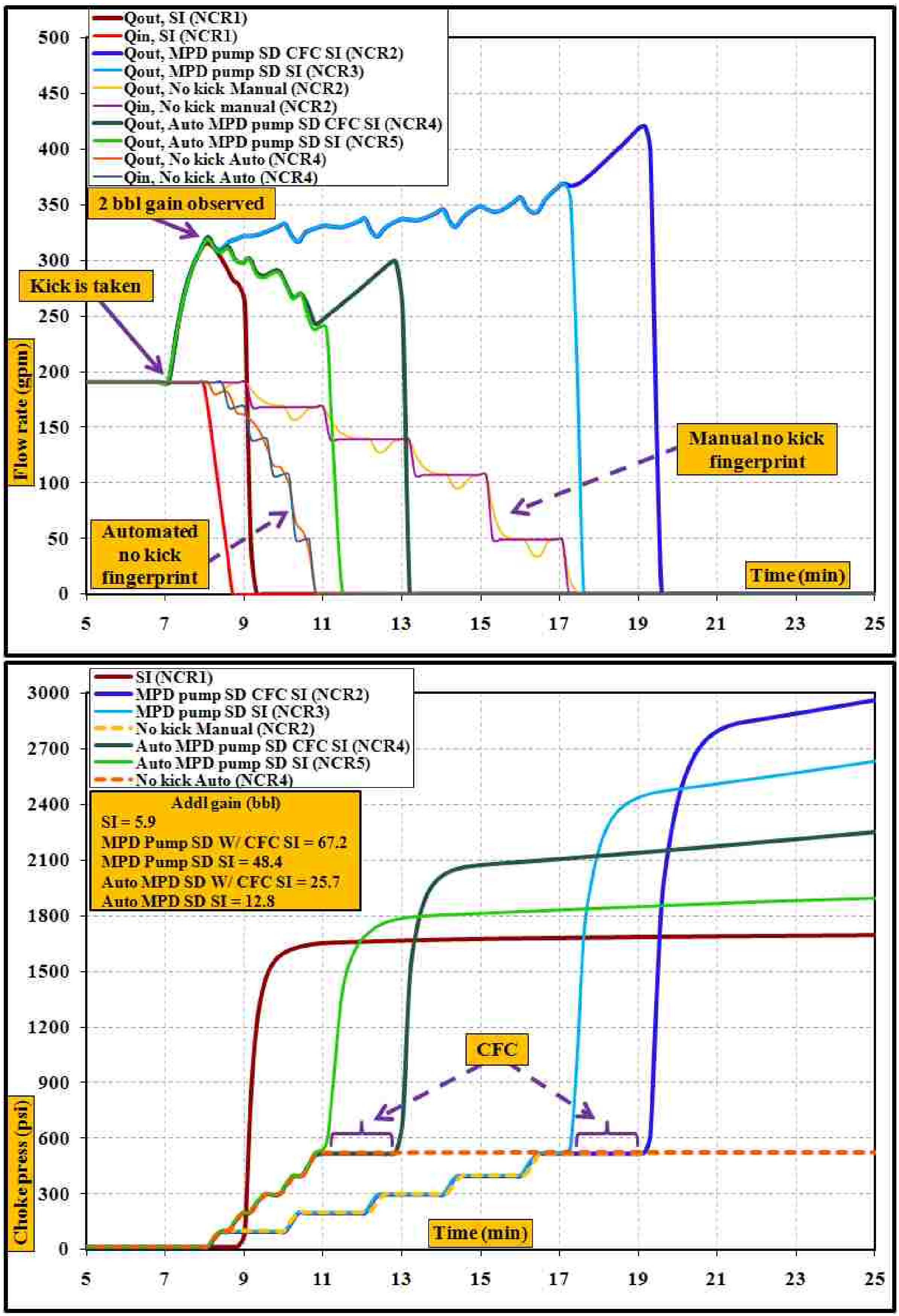
Initial response	Permeability	Initial gain	Circ UB @ 190 gpm	Case code	Page
Non-Circ	High k	2 bbl	0.1 ppge	C1	164
			0.5 ppge	C2	165
			1.2 ppge	C3	166
		20 bbl	0.1 ppge	C4	167
			0.5 ppge	C5	168
			1.2 ppge	C6	169
	Low k	2 bbl	0.1 ppge	C7	170
			0.5 ppge	C8	171
			1.2 ppge	C9	172
		20 bbl	0.1 ppge	C10	173
			0.5 ppge	C11	174
			1.2 ppge	C12	175
Circ	High k	2 bbl	0.1 ppge	C13	176
			0.5 ppge	C14	177
			1.2 ppge	C15	178
		20 bbl	0.1 ppge	C16	179
			0.5 ppge	C17	180
			1.2 ppge	C18	181
	Low k	2 bbl	0.1 ppge	C19	182
			0.5 ppge	C20	183
			1.2 ppge	C21	184
		20 bbl	0.1 ppge	C22	185
			0.5 ppge	C23	186
			1.2 ppge	C24	187



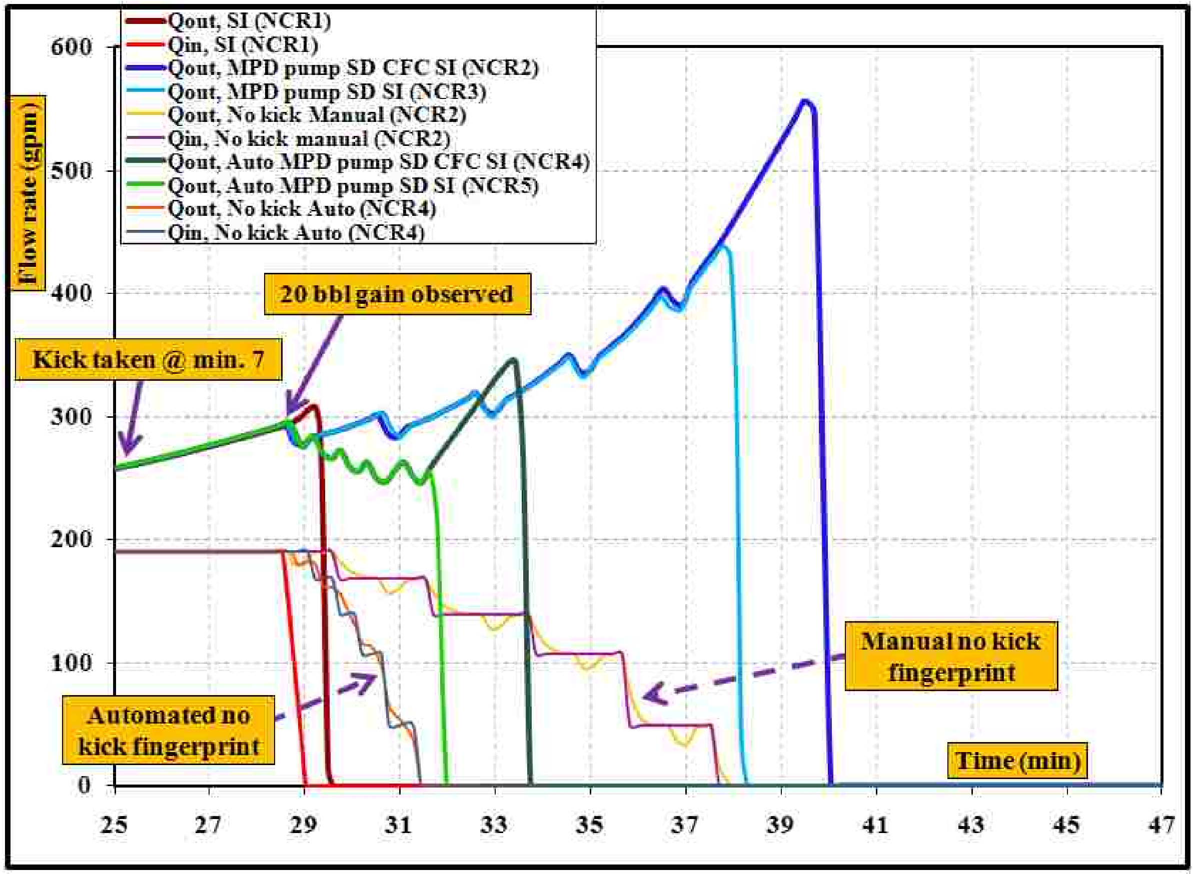
C1: Well X, application of NCRs on 2 bbl kick / high k / 0.1 ppge Circ UB

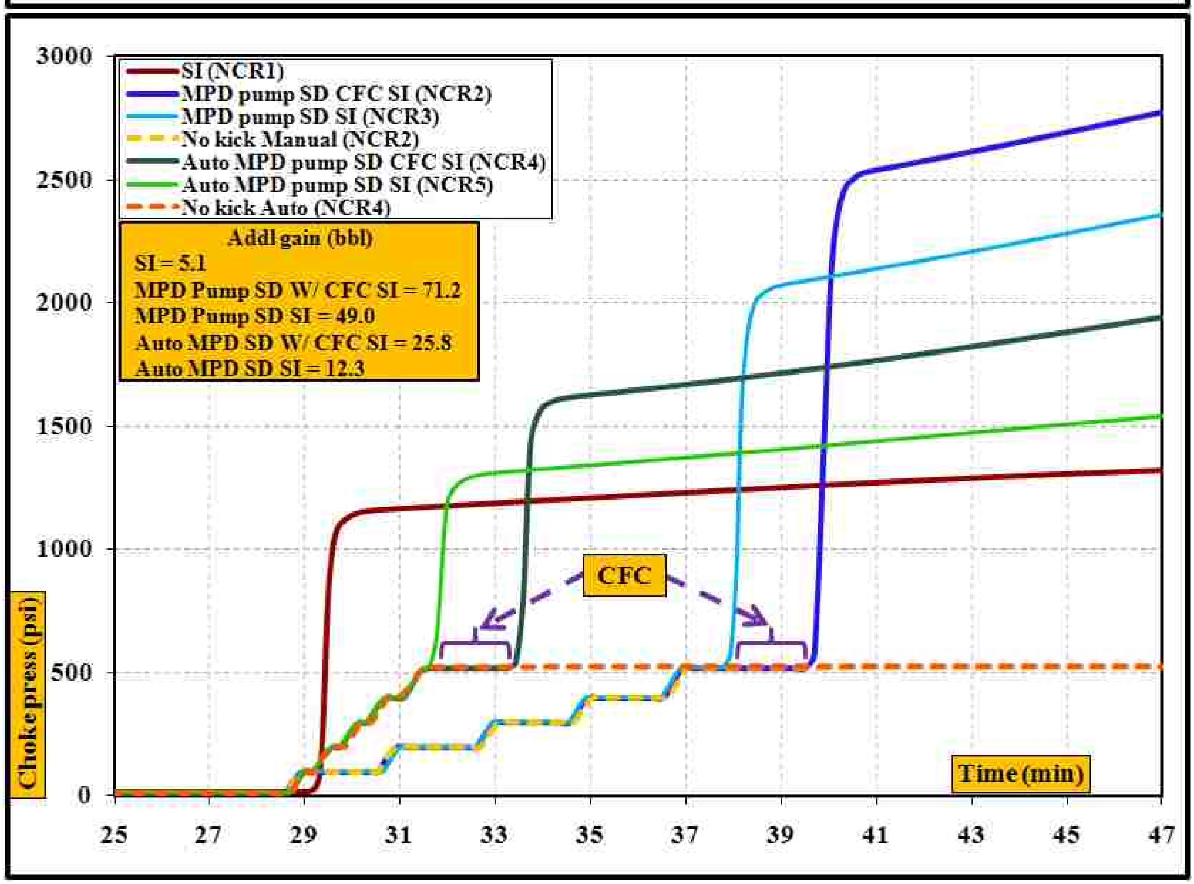


C2: Well X, application of NCRs on 2 bbl kick / high k / 0.5 ppge Circ UB

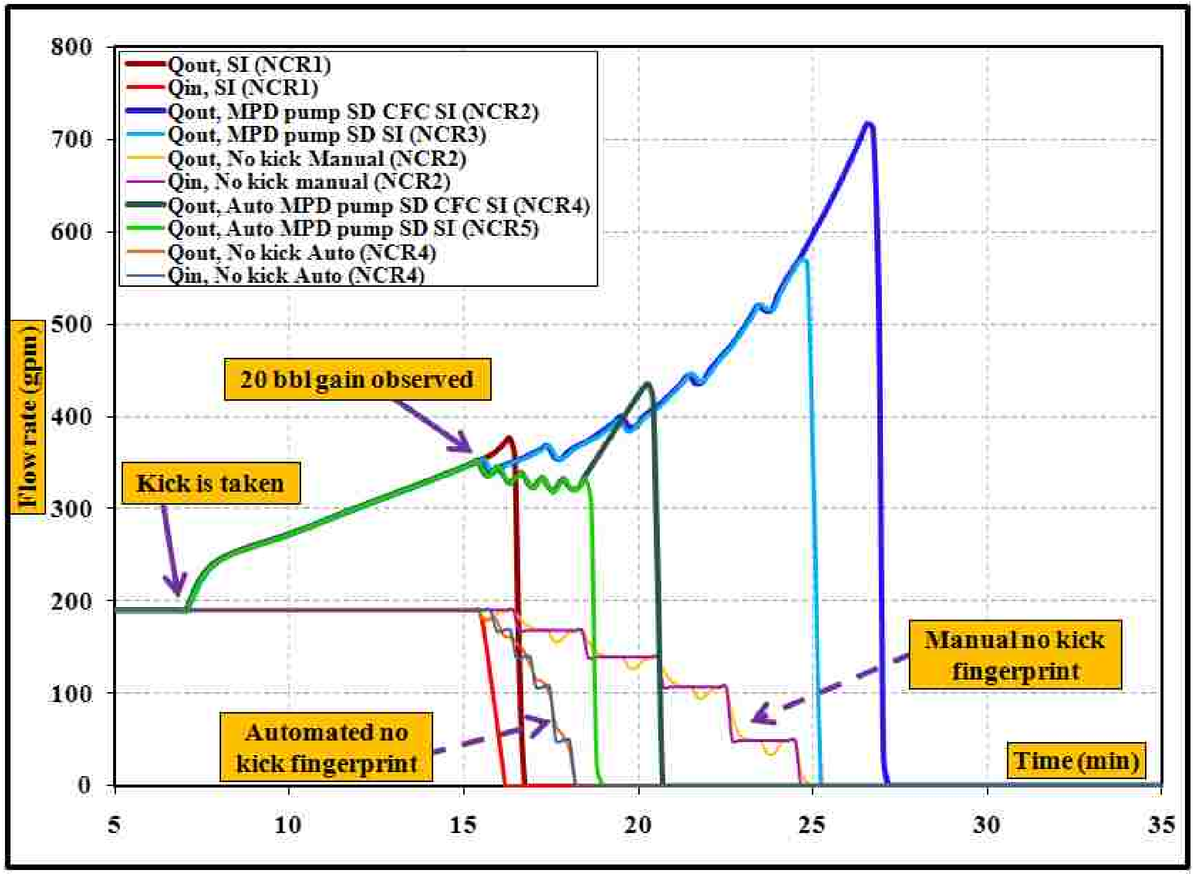


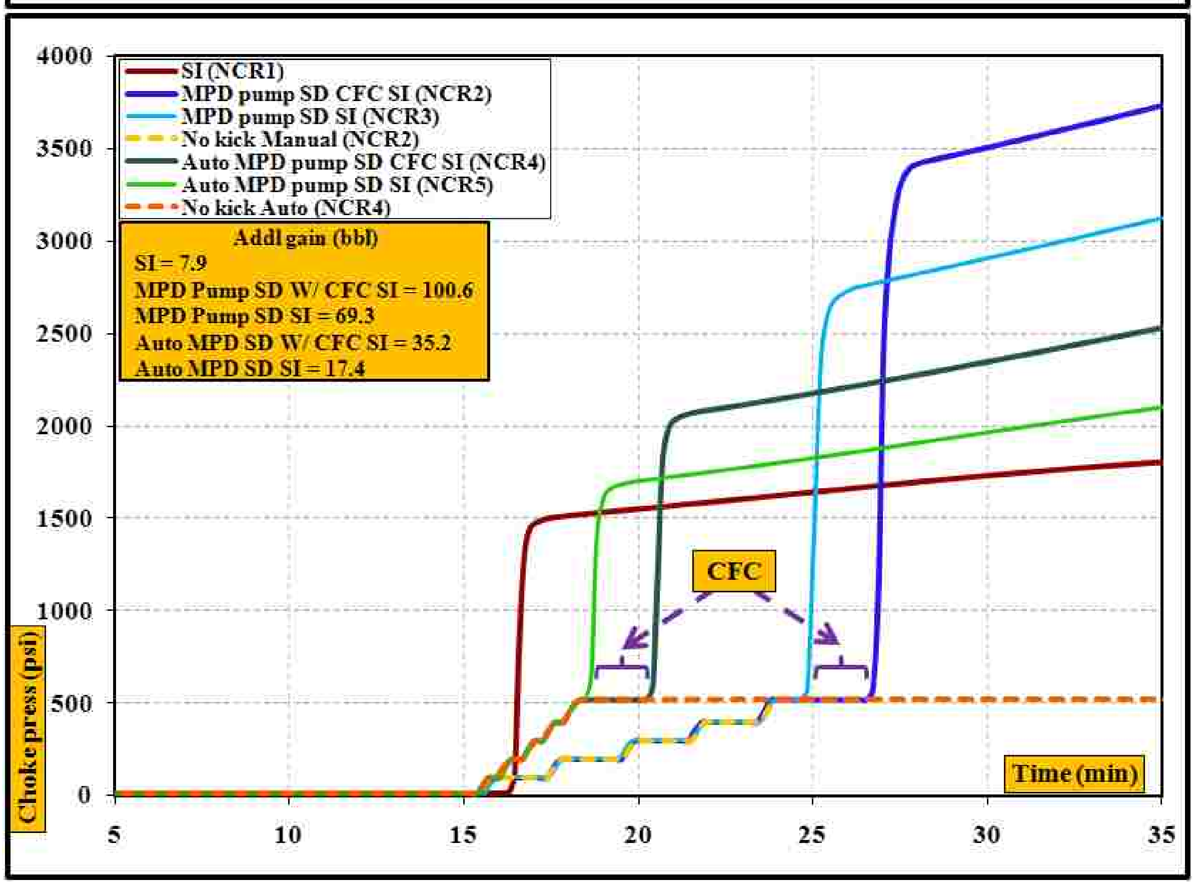
C3: Well X, application of NCRs on 2 bbl kick / high k / 1.2 ppge Circ UB



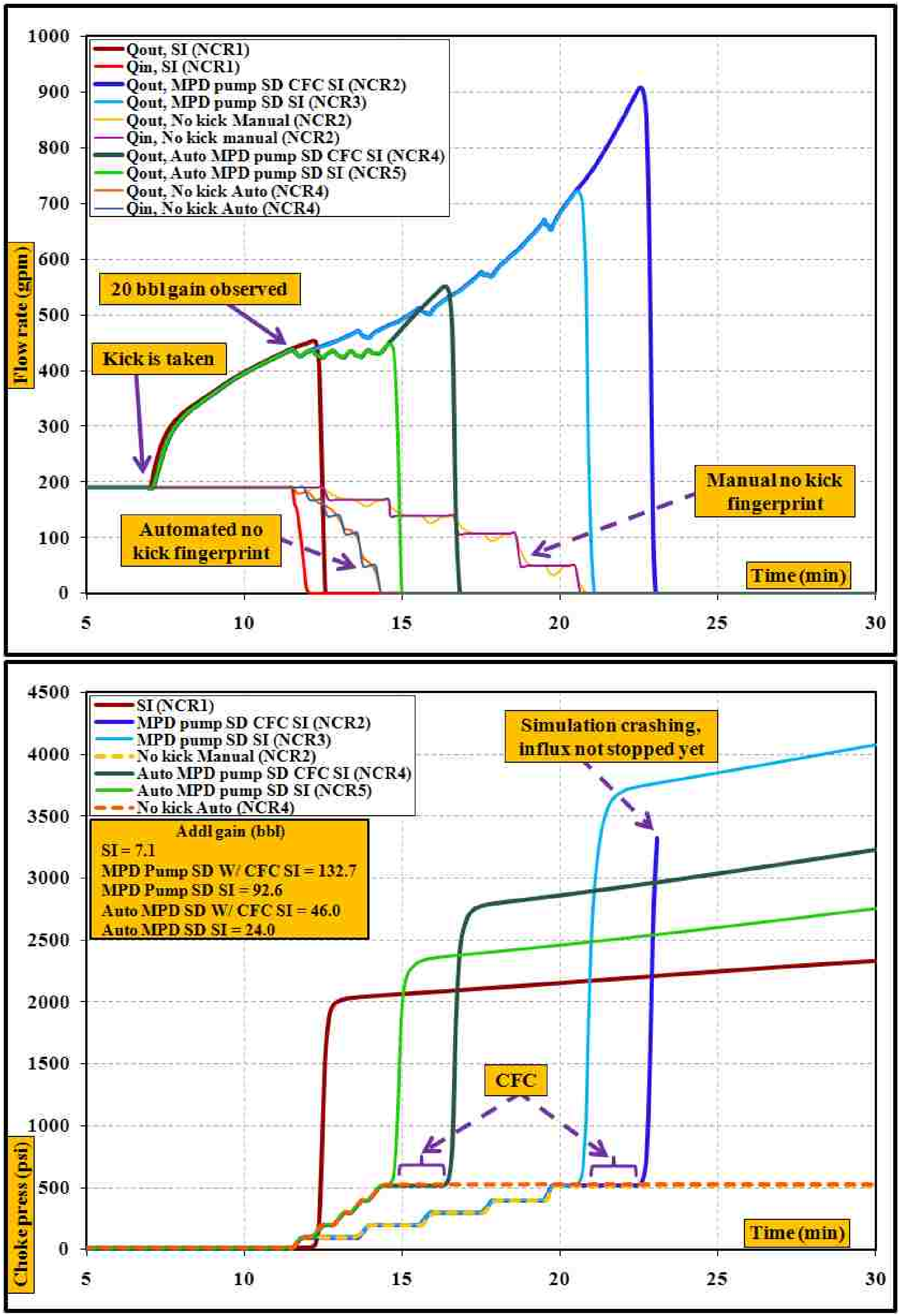


C4: Well X, application of NCRs on 20 bbl kick / high k / 0.1 ppge Circ UB

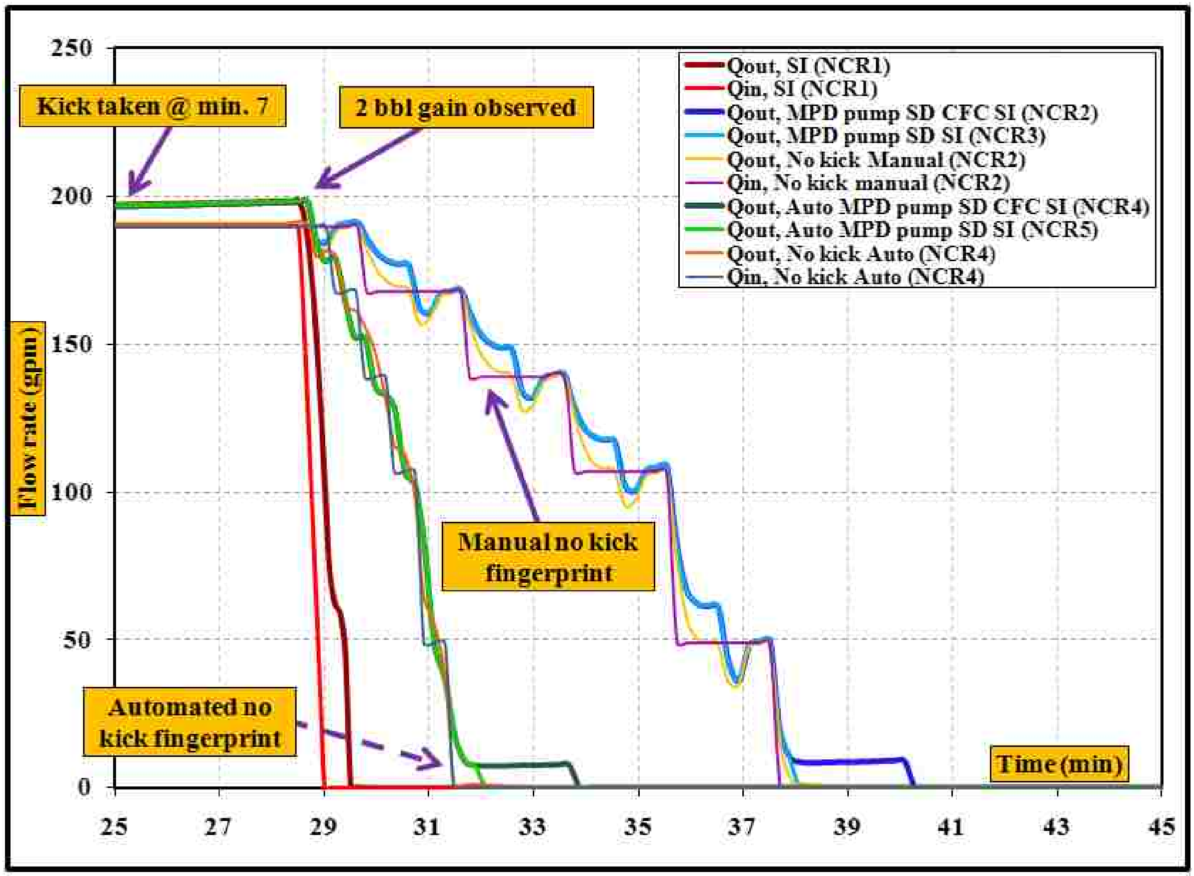


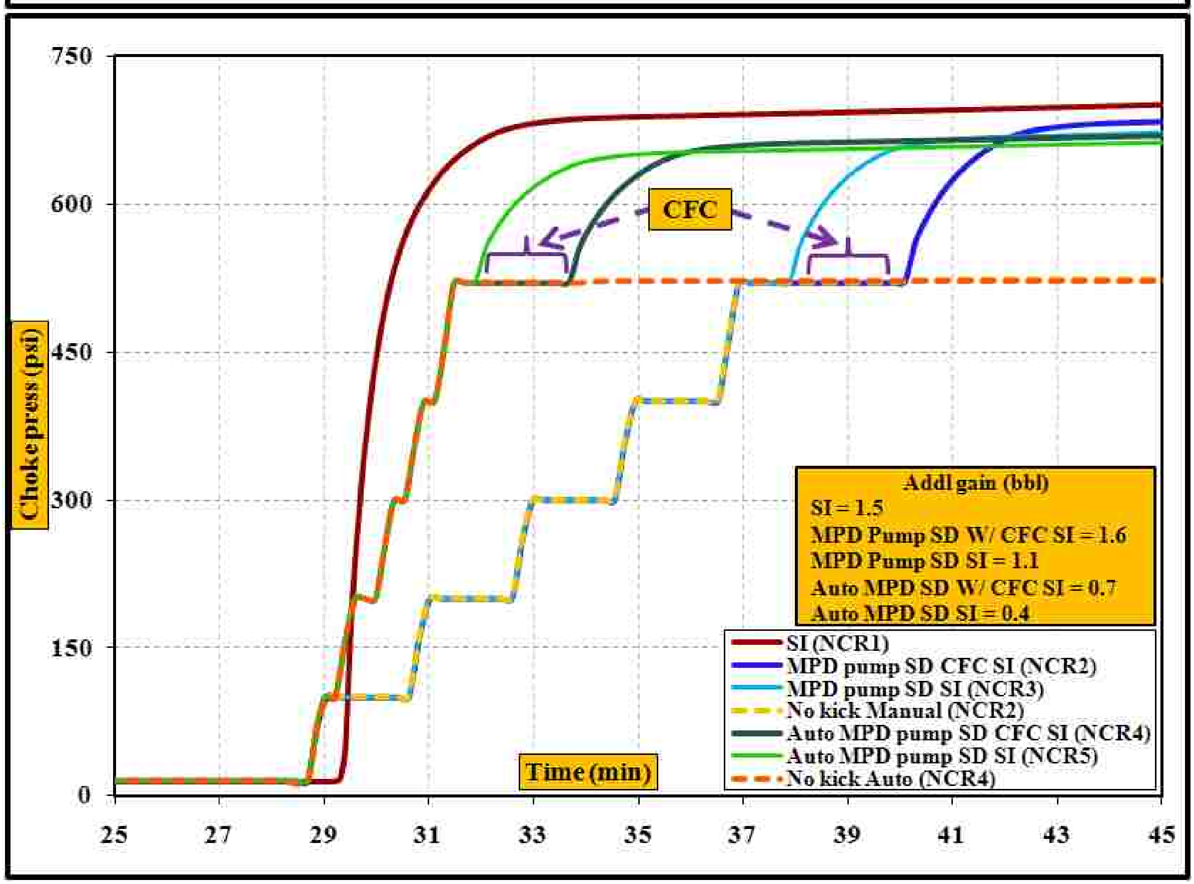


C5: Well X, application of NCRs on 20 bbl kick / high k / 0.5 ppge Circ UB

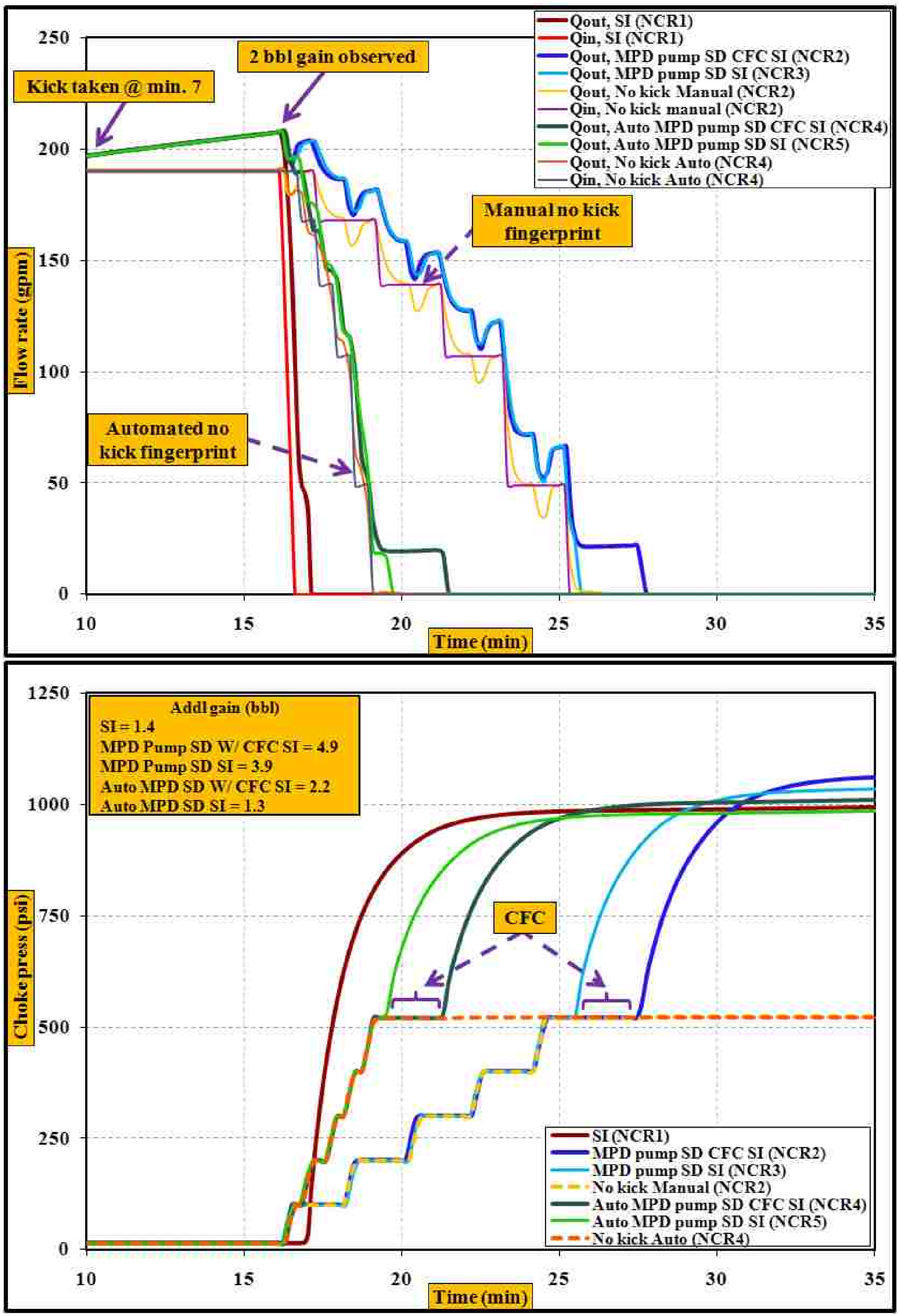


C6: Well X, application of NCRs on 20 bbl kick / high k / 1.2 ppge Circ UB

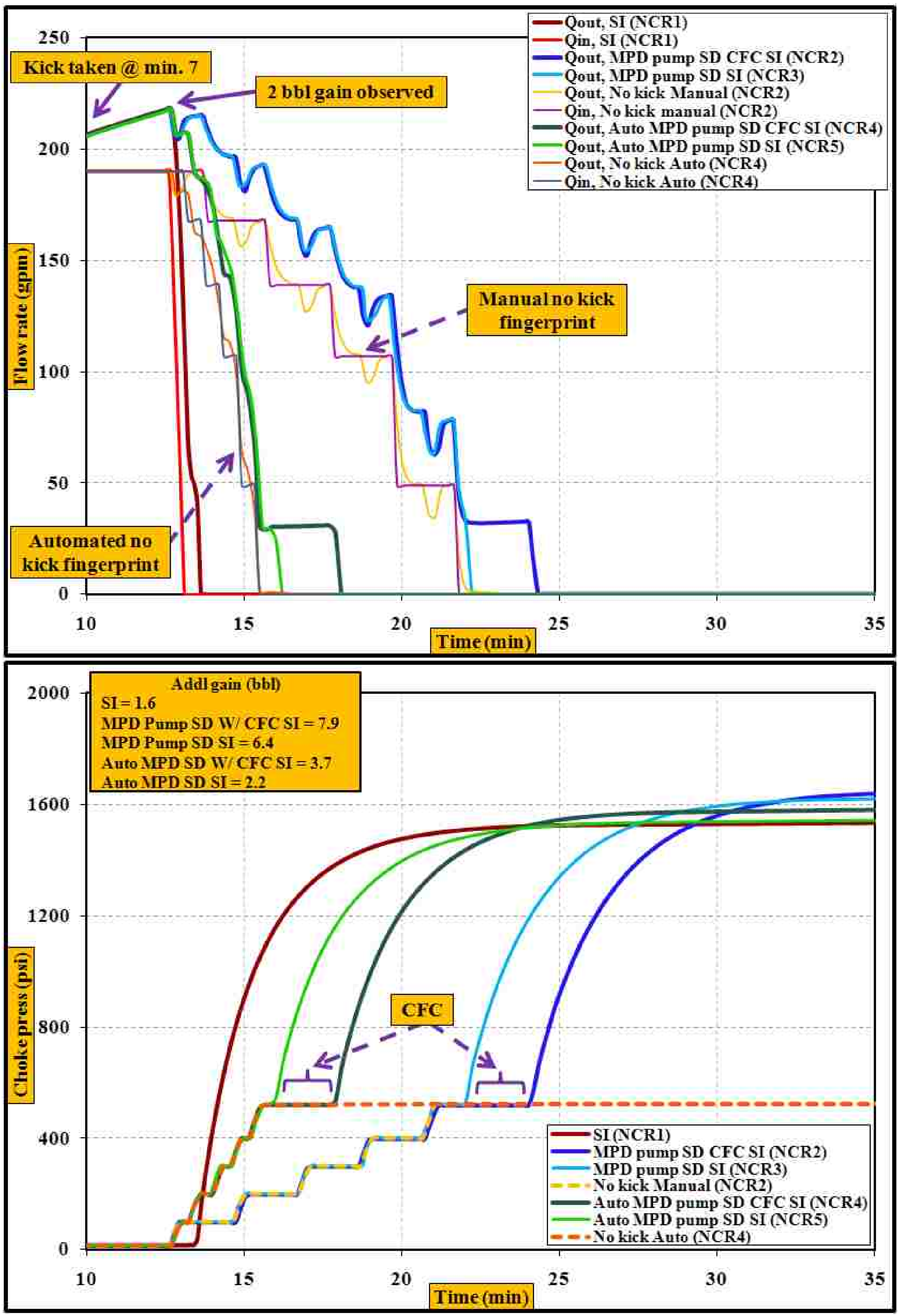




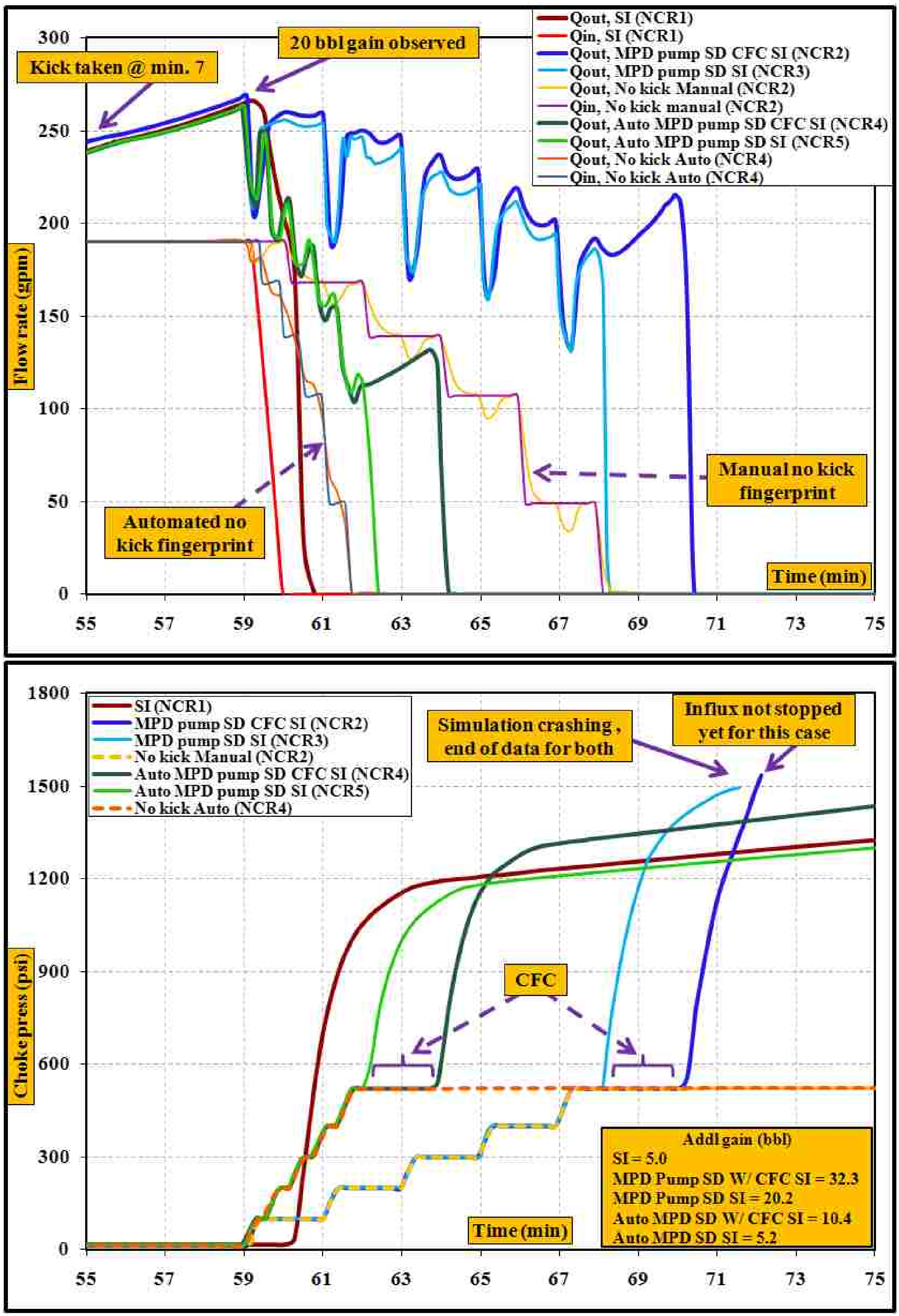
C7: Well X, application of NCRs on 2 bbl kick / low k / 0.1 ppge Circ UB



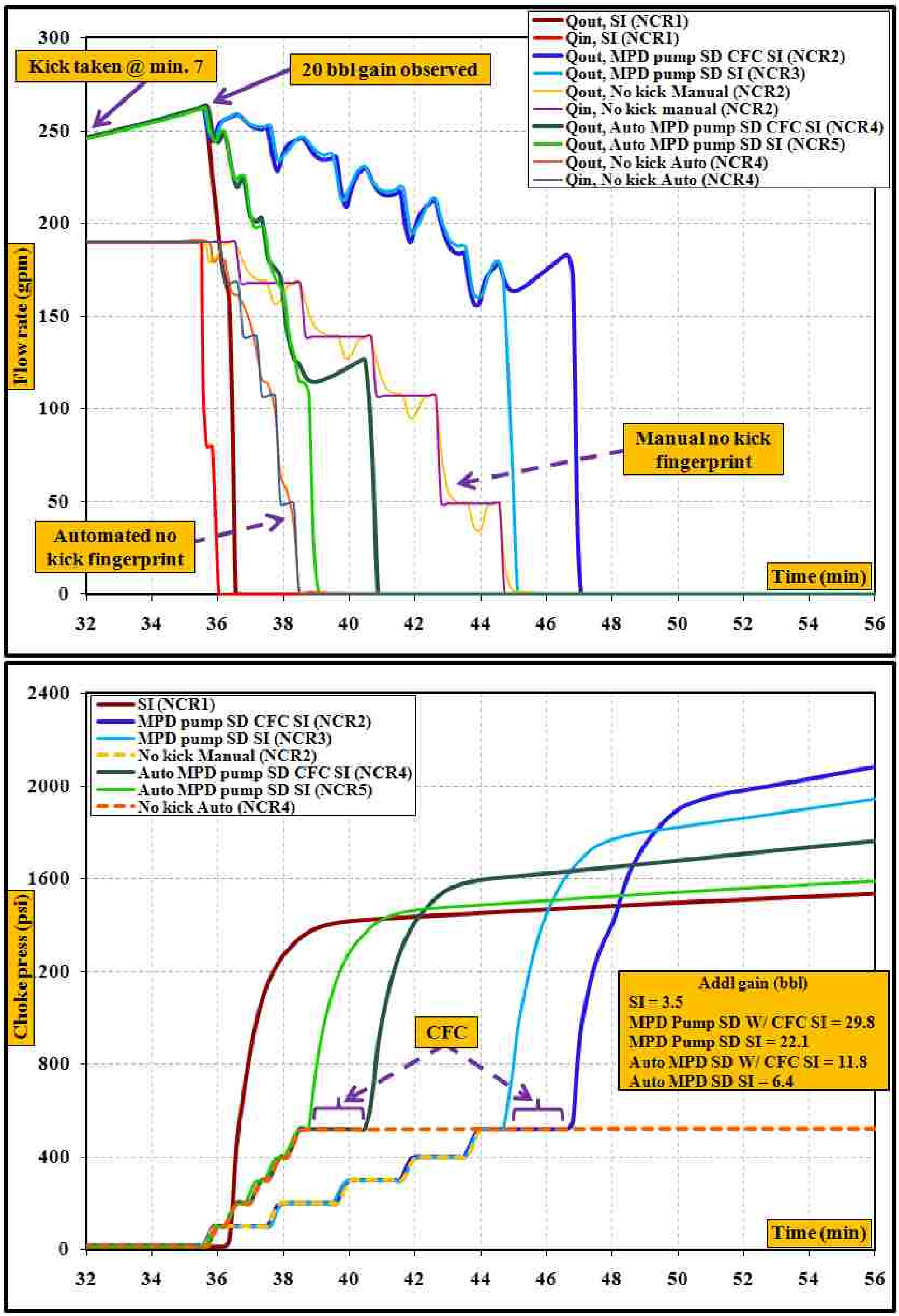
C8: Well X, application of NCRs on 2 bbl kick / low k / 0.5 ppge Circ UB



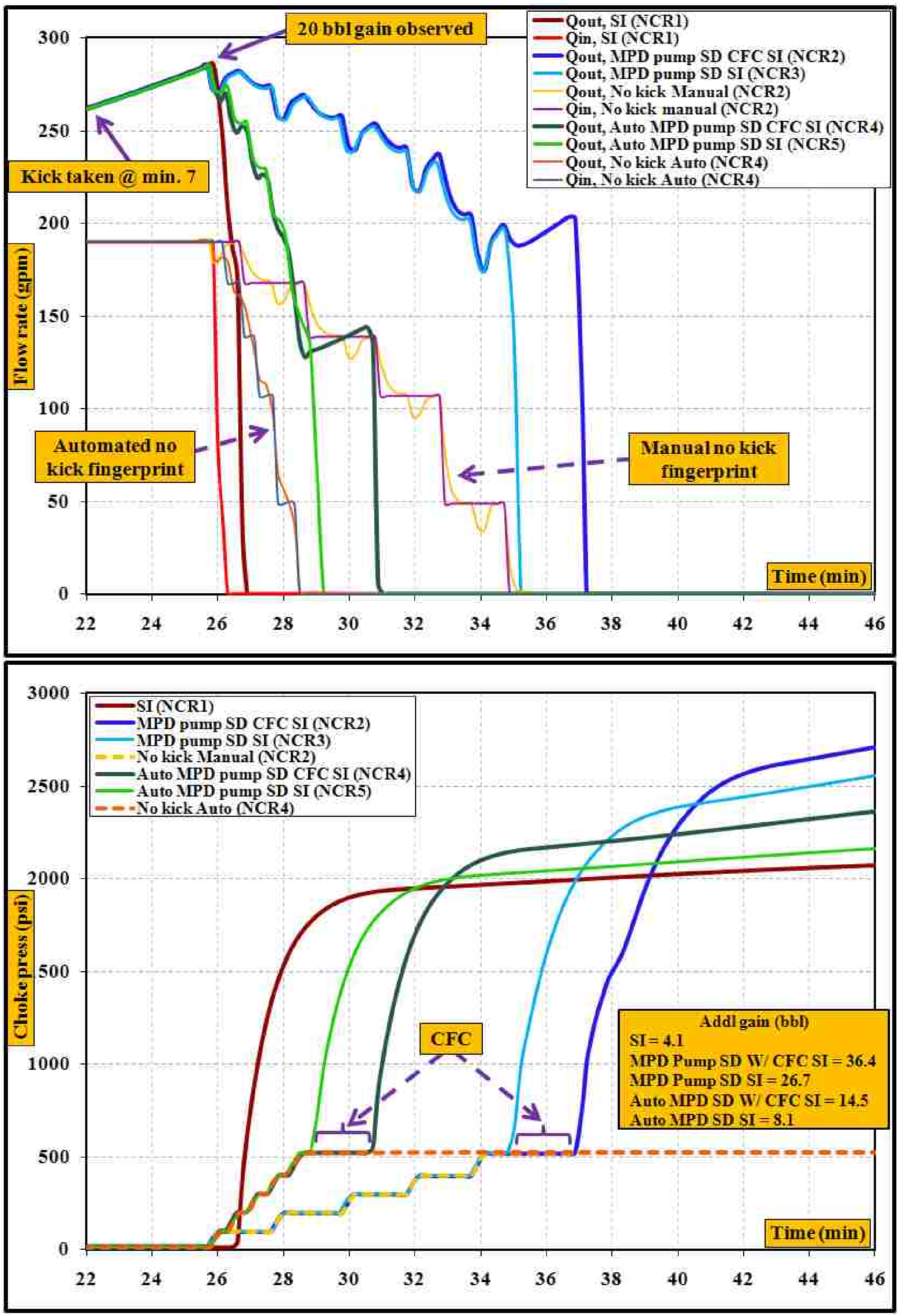
C9: Well X, application of NCRs on 2 bbl kick / low k / 1.2 ppge Circ UB



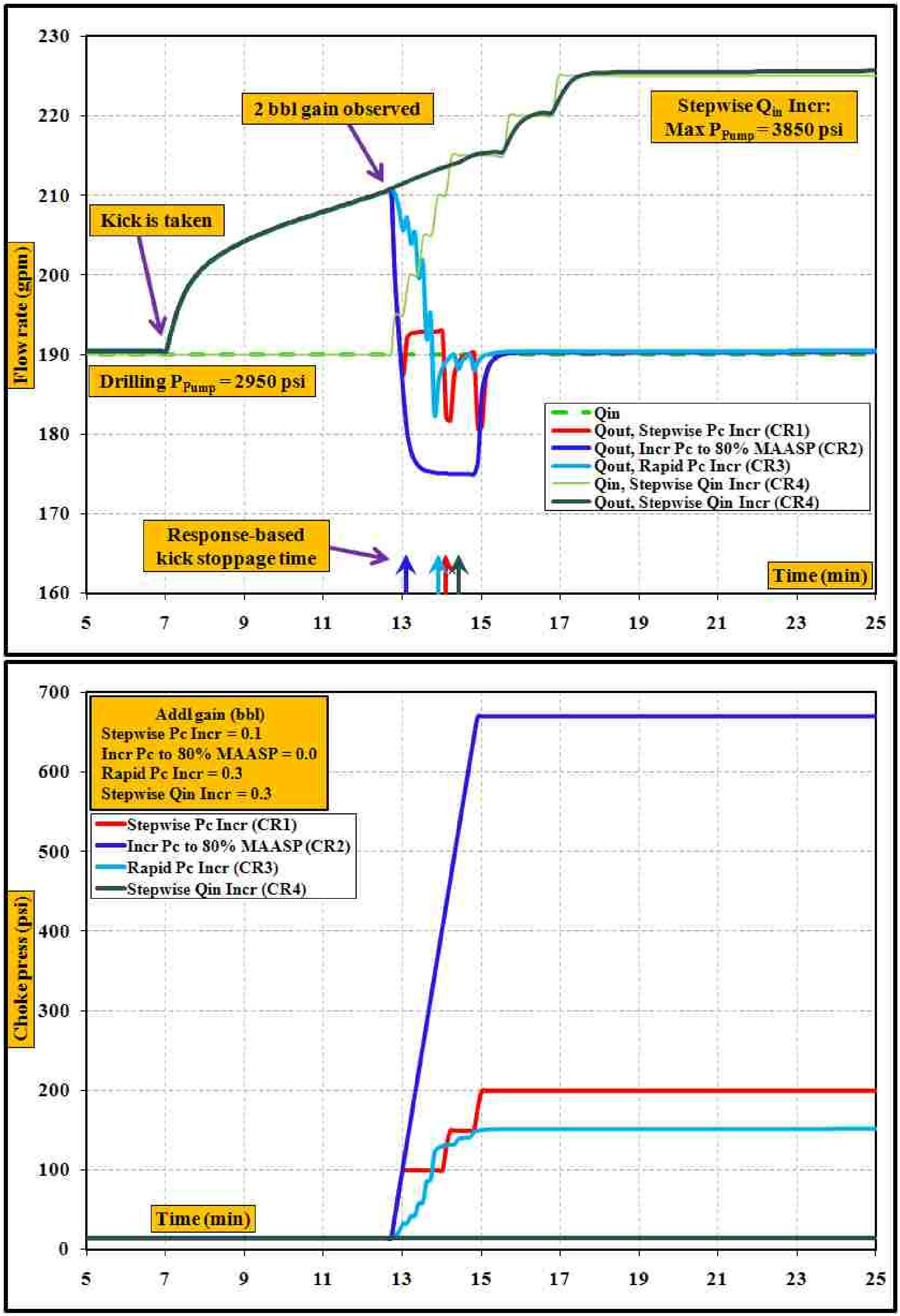
C10: Well X, application of NCRs on 20 bbl kick / low k / 0.1 ppge Circ UB



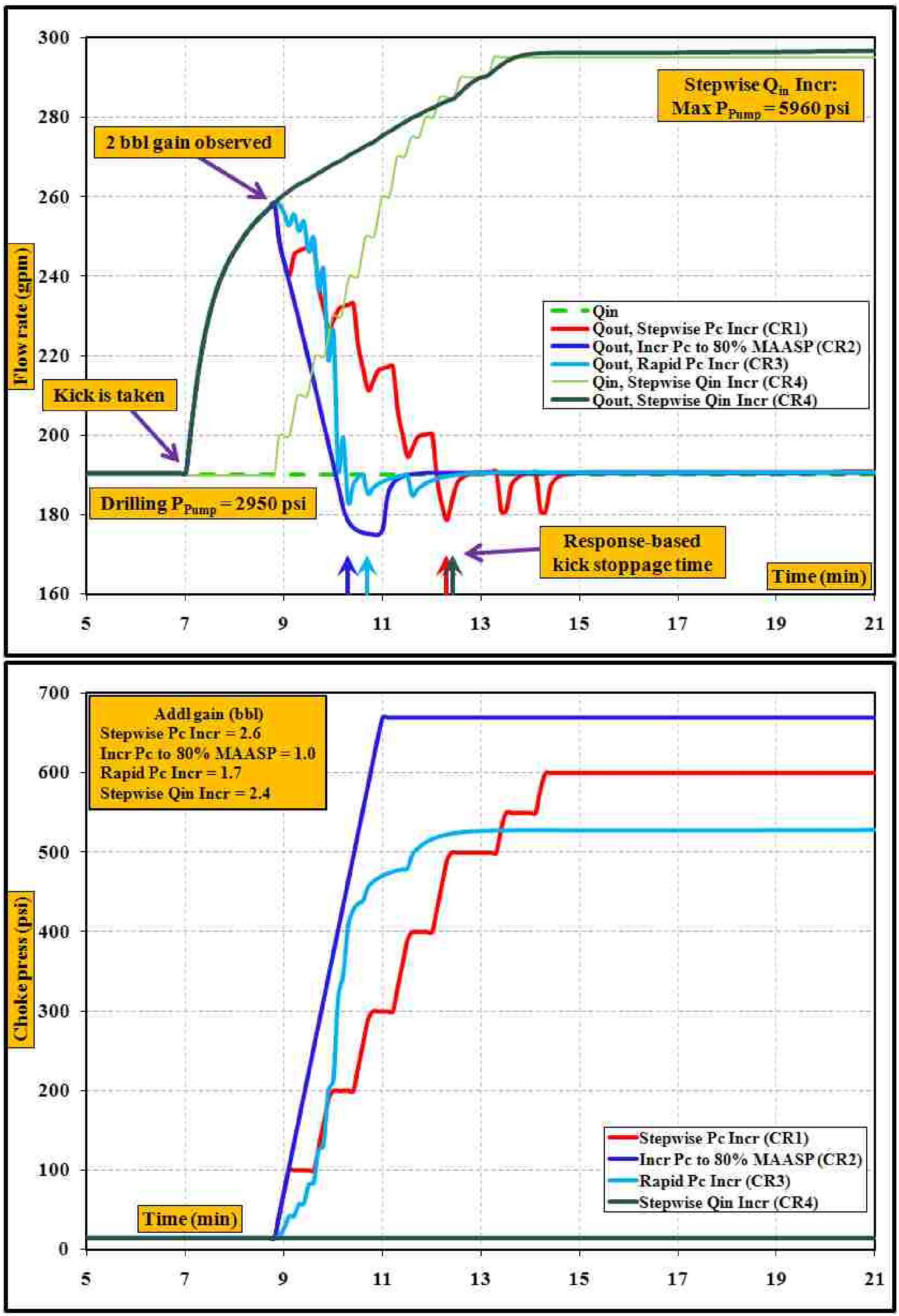
C11: Well X, application of NCRs on 20 bbl kick / low k / 0.5 ppge Circ UB



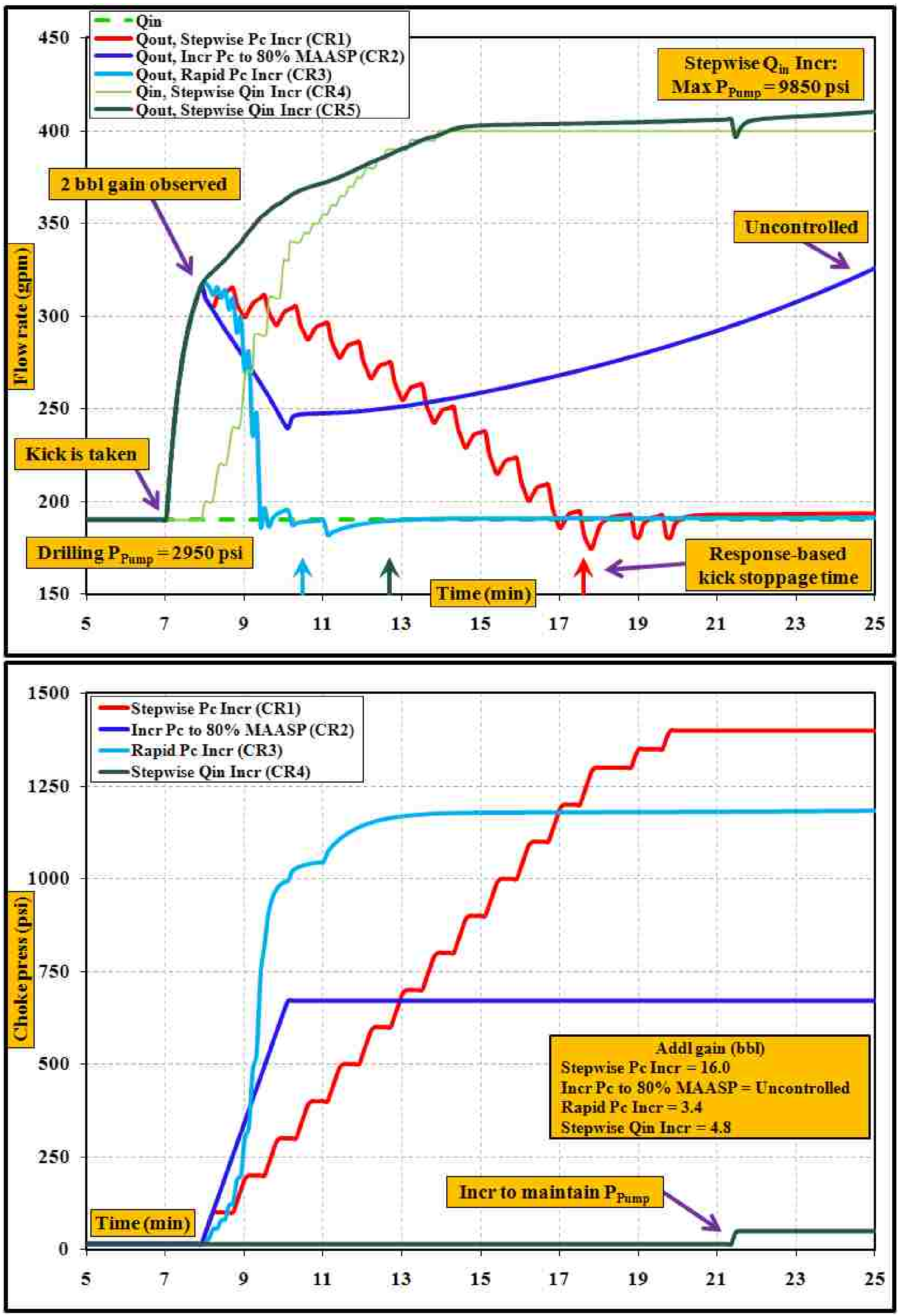
C12: Well X, application of NCRs on 20 bbl kick / low k / 1.2 ppge Circ UB



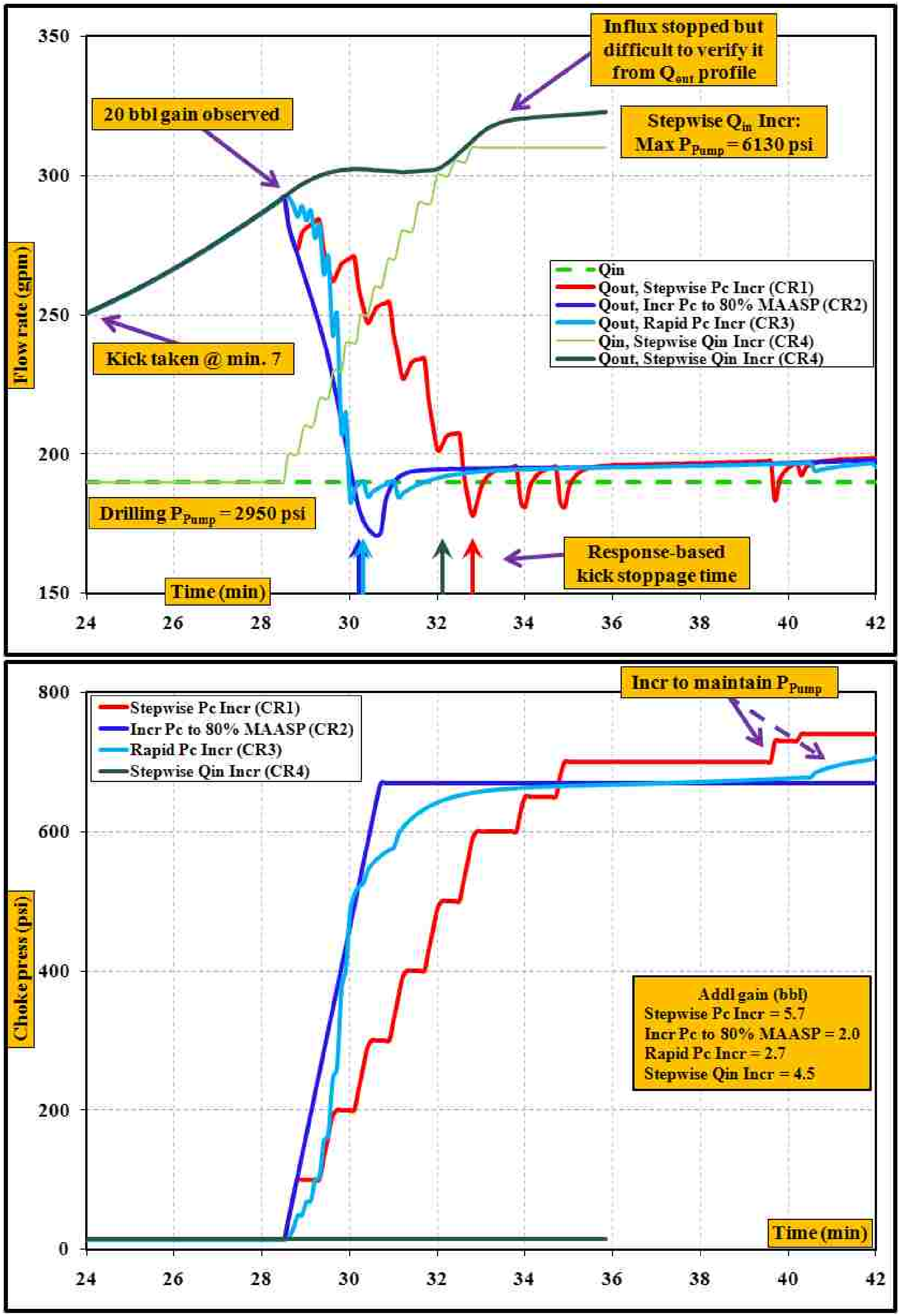
C13: Well X, application of CRs on 2 bbl kick / high k / 0.1 ppge Circ UB



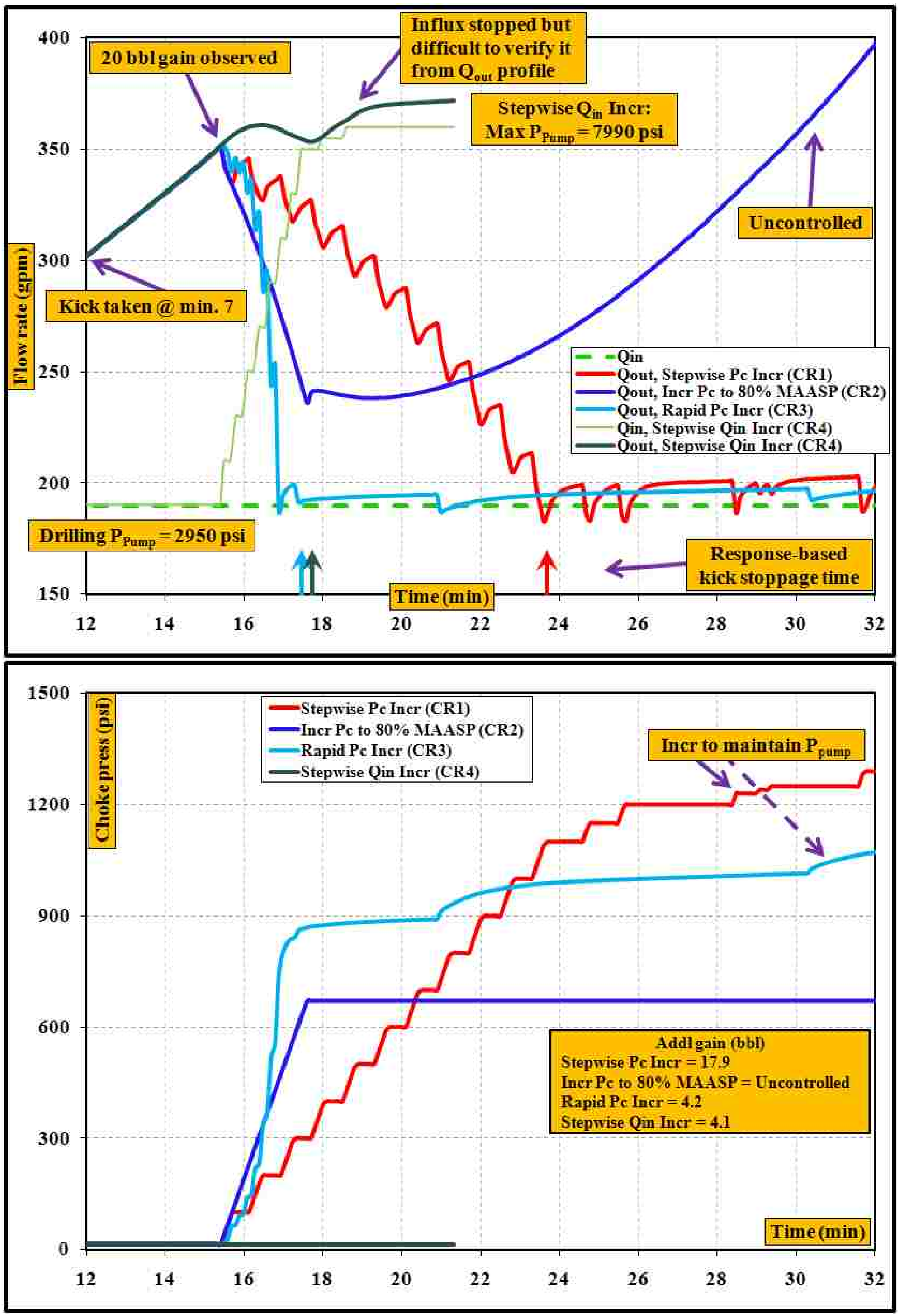
C14: Well X, application of CRs on 2 bbl kick / high k / 0.5 ppge Circ UB



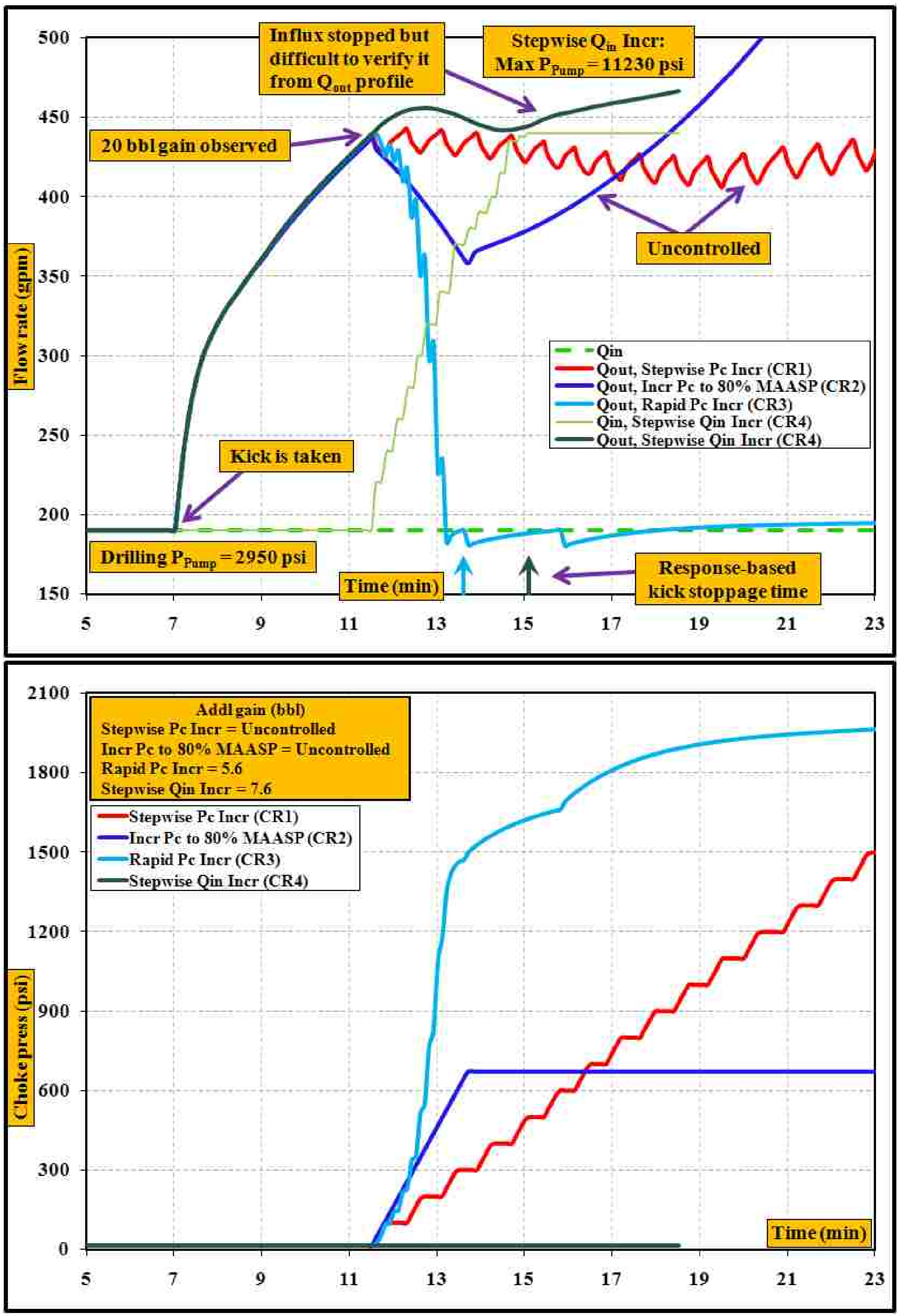
C15: Well X, application of CRs on 2 bbl kick / high k / 1.2 ppge Circ UB



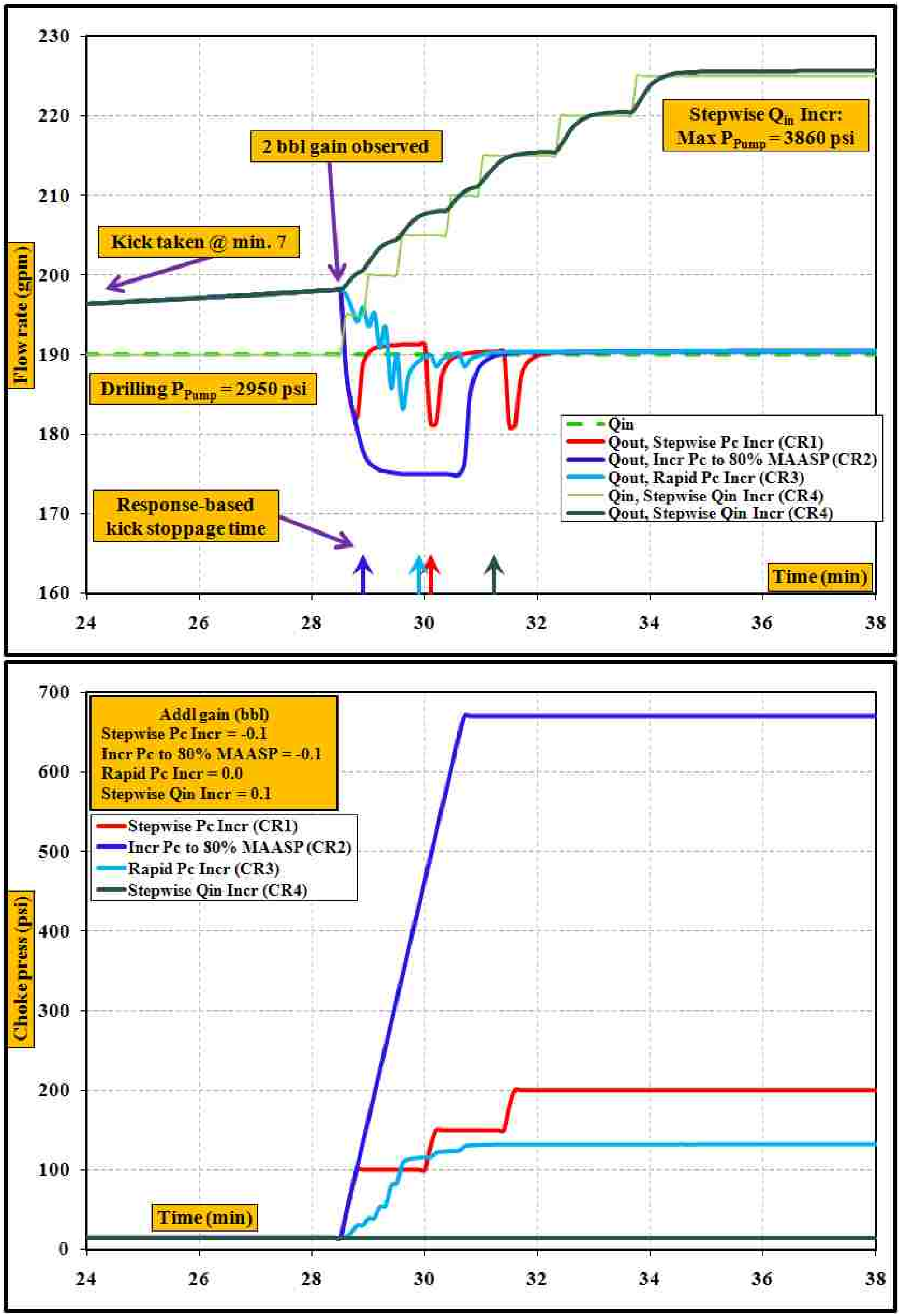
C16: Well X, application of CRs on 20 bbl kick / high k / 0.1 ppge Circ UB



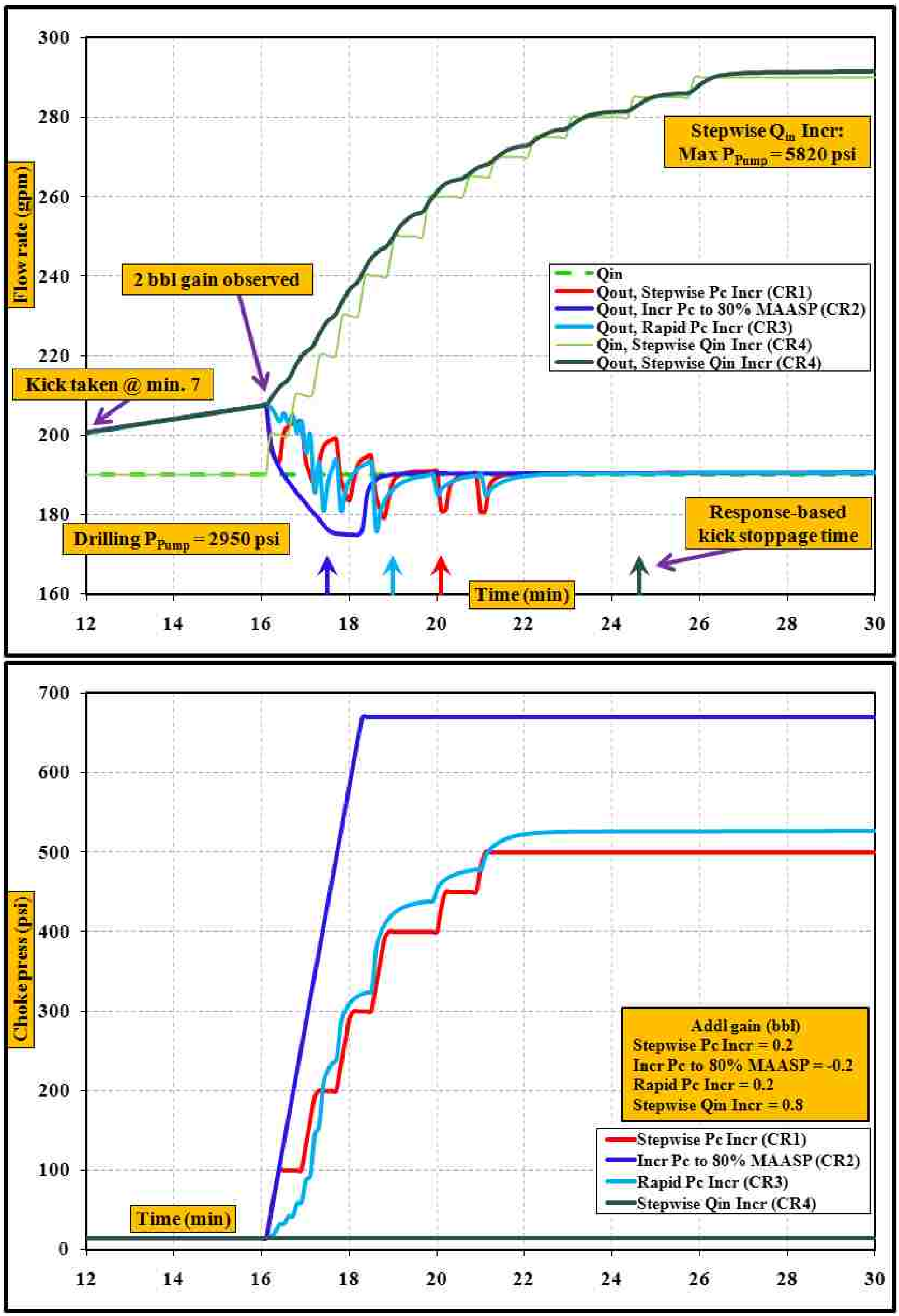
C17: Well X, application of CRs on 20 bbl kick / high k / 0.5 ppge Circ UB



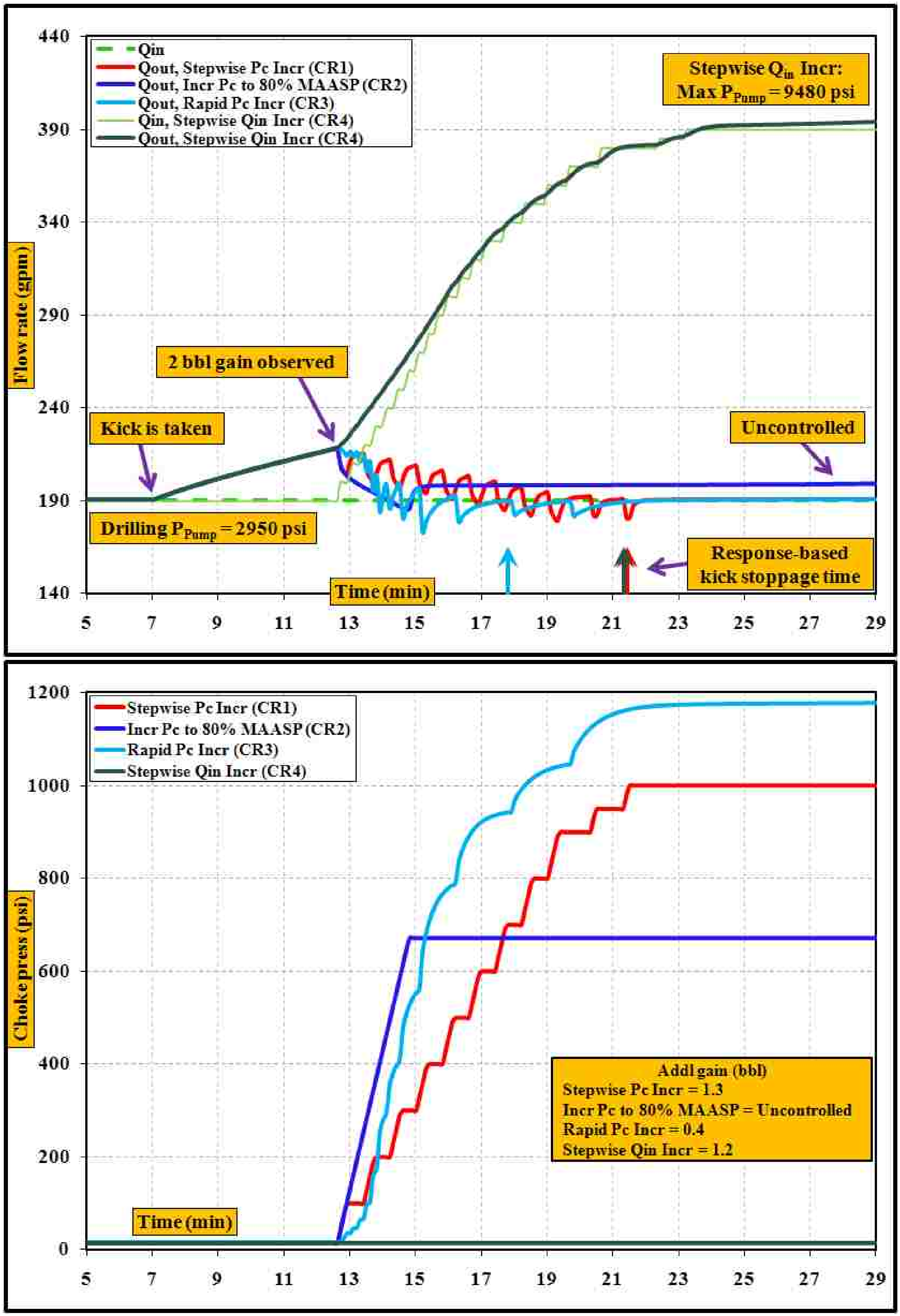
C18: Well X, application of CRs on 20 bbl kick / high k / 1.2 ppge Circ UB



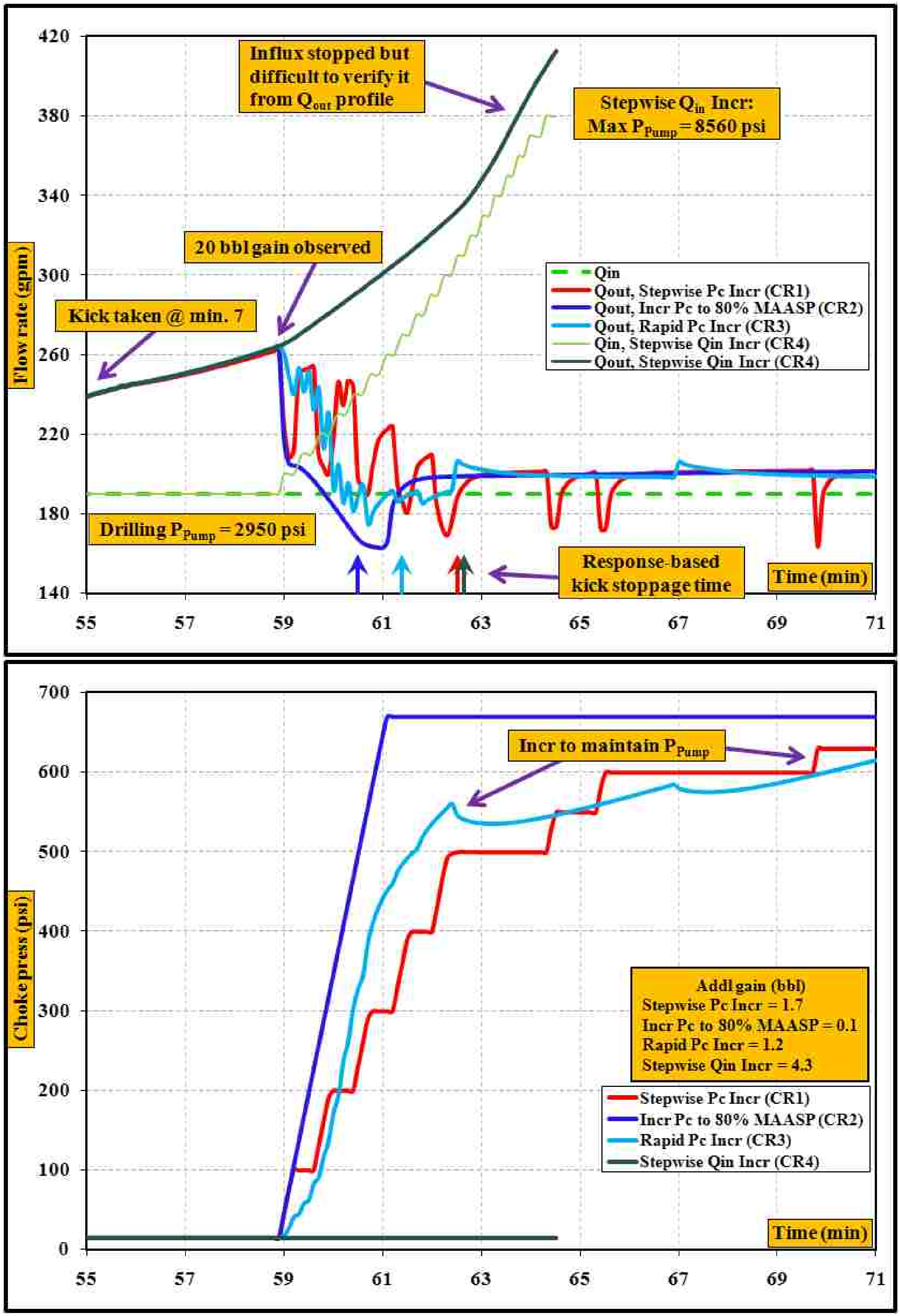
C19: Well X, application of CRs on 2 bbl kick / low k / 0.1 ppge Circ UB



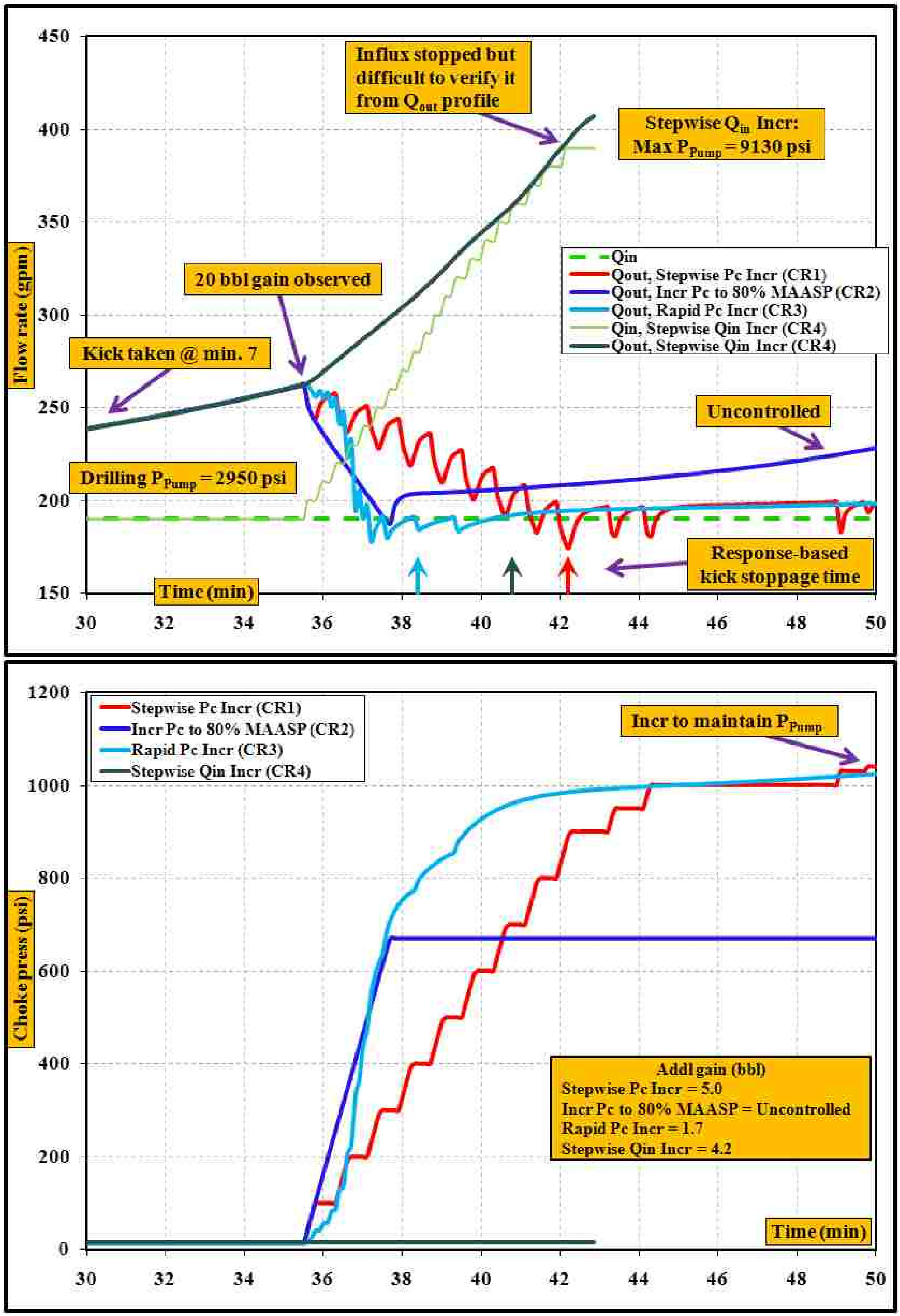
C20: Well X, application of CRs on 2 bbl kick / low k / 0.5 ppge Circ UB



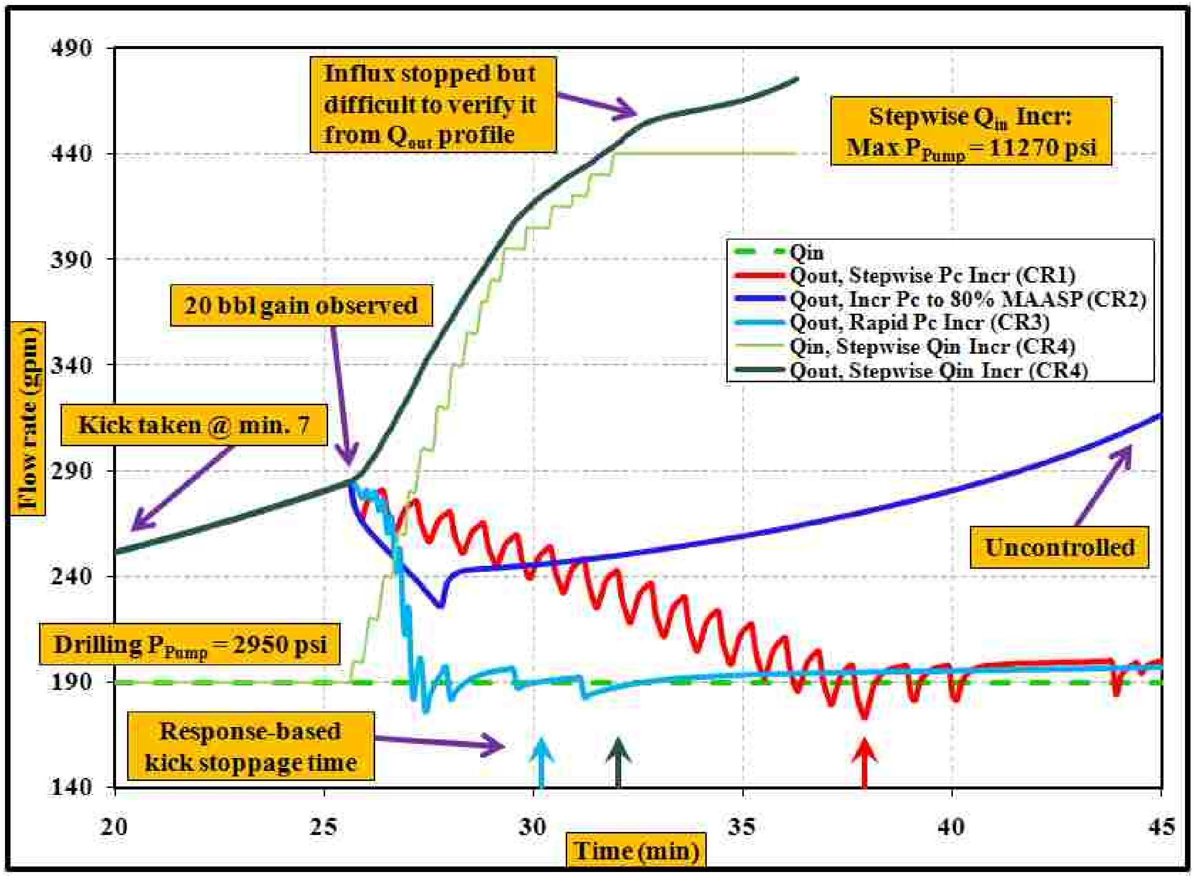
C21: Well X, application of CRs on 2 bbl kick / low k / 1.2 ppge Circ UB

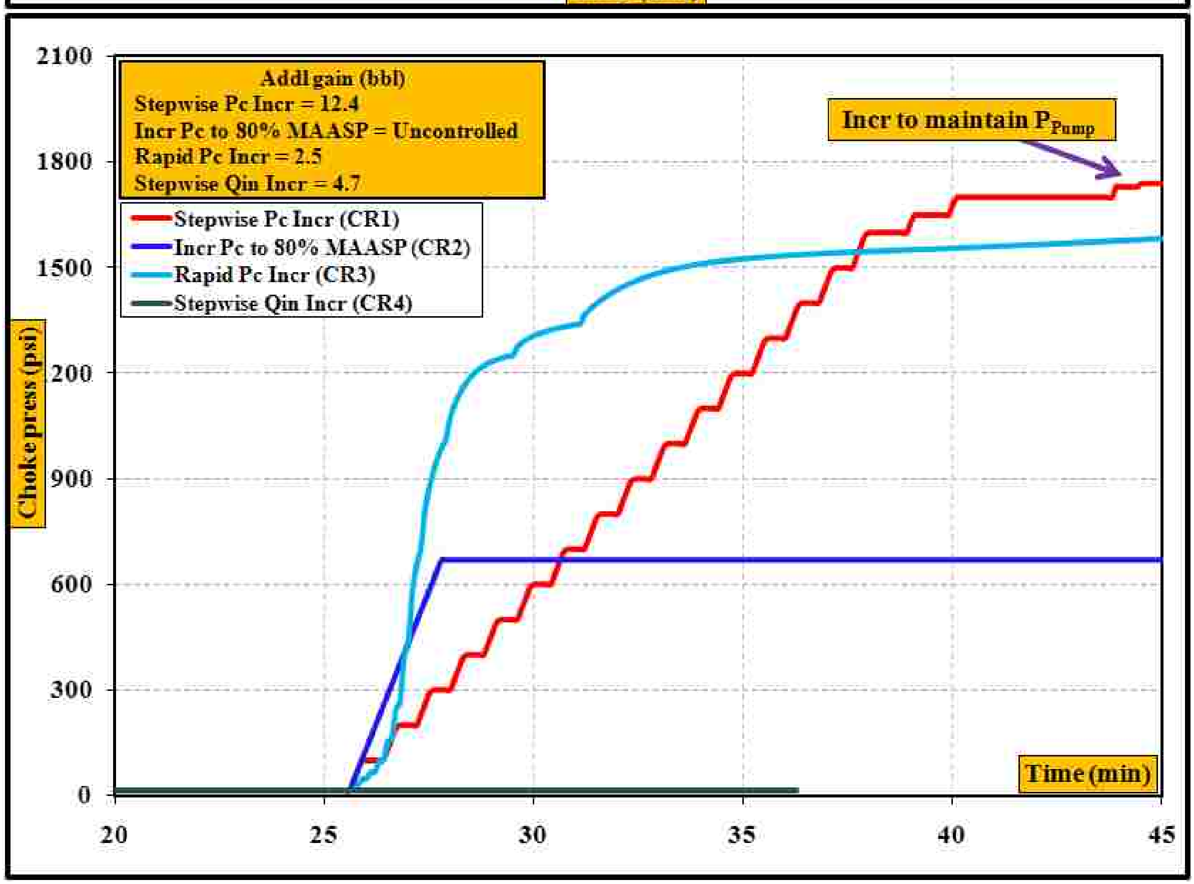


C22: Well X, application of CRs on 20 bbl kick / low k / 0.1 ppge Circ UB



C23: Well X, application of CRs on 20 bbl kick / low k / 0.5 ppge Circ UB

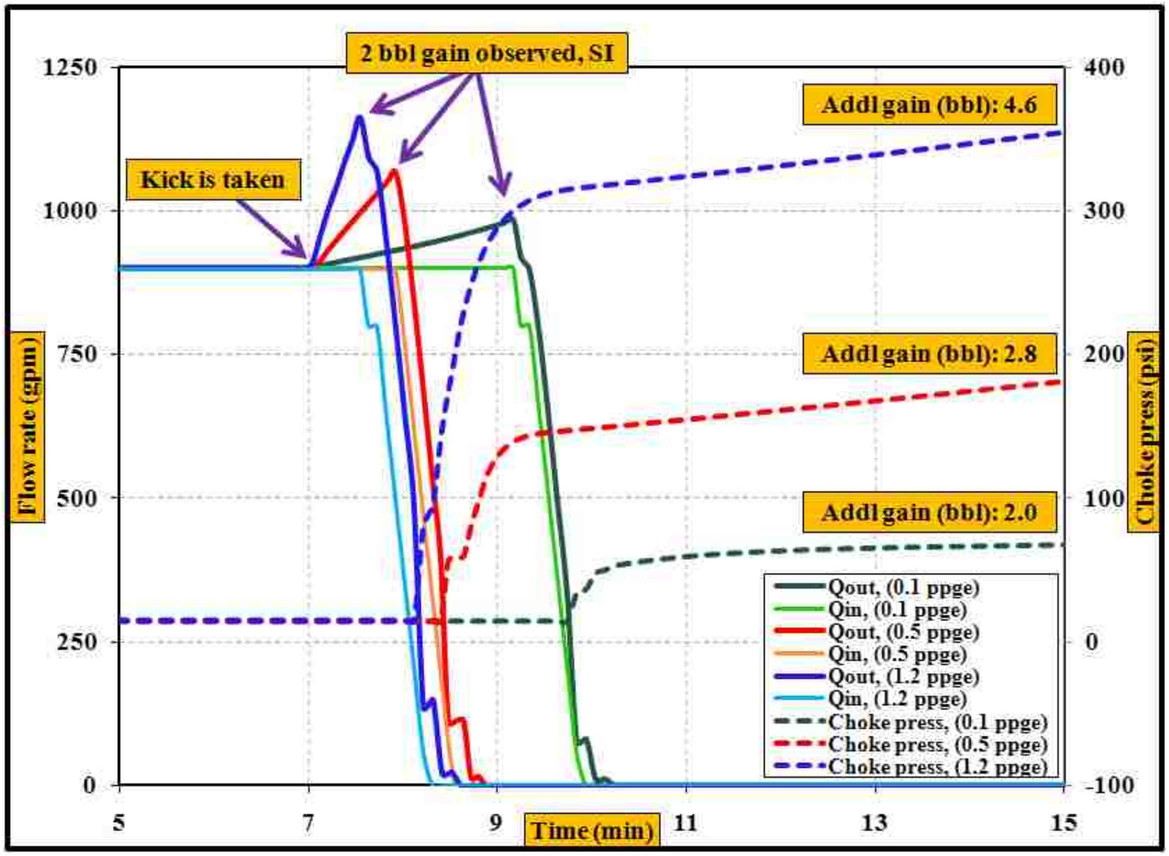




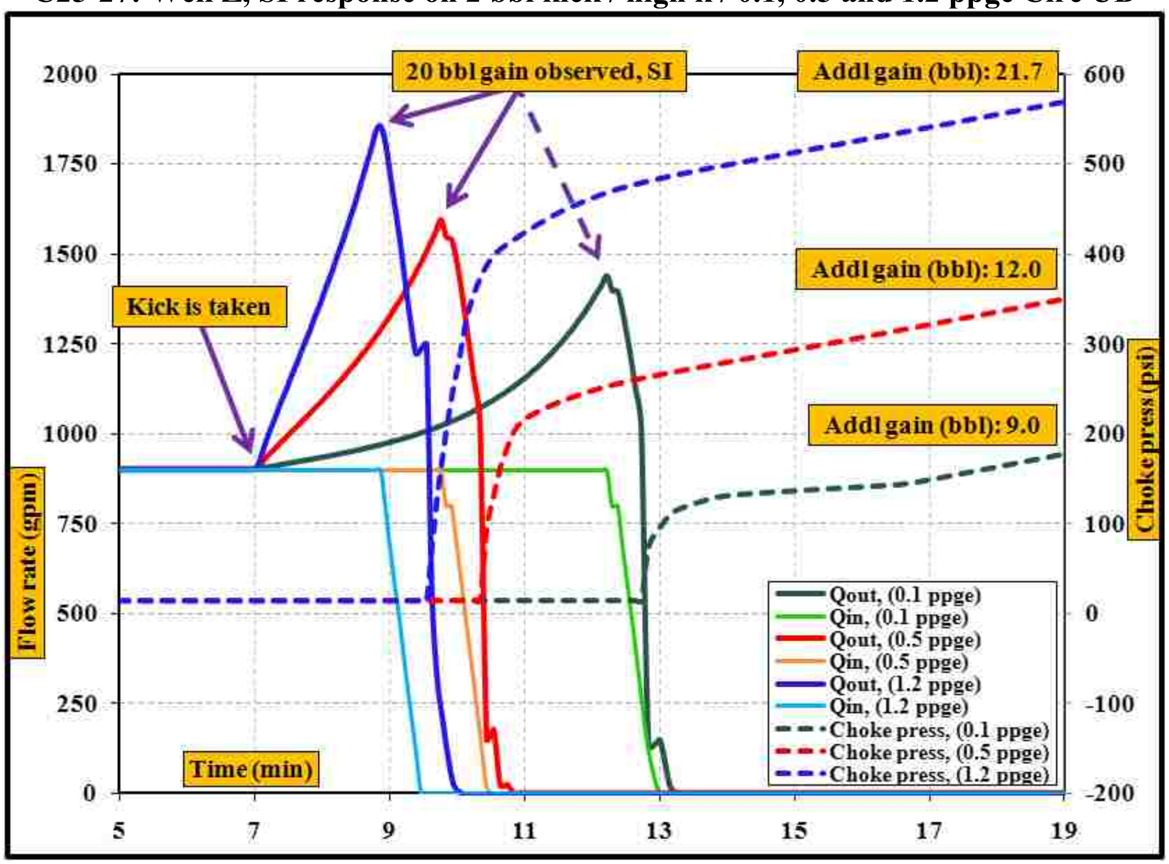
C24: Well X, application of CRs on 20 bbl kick / low k / 1.2 ppge Circ UB

INDEX FOR WELL Z SIMULATION PLOTS

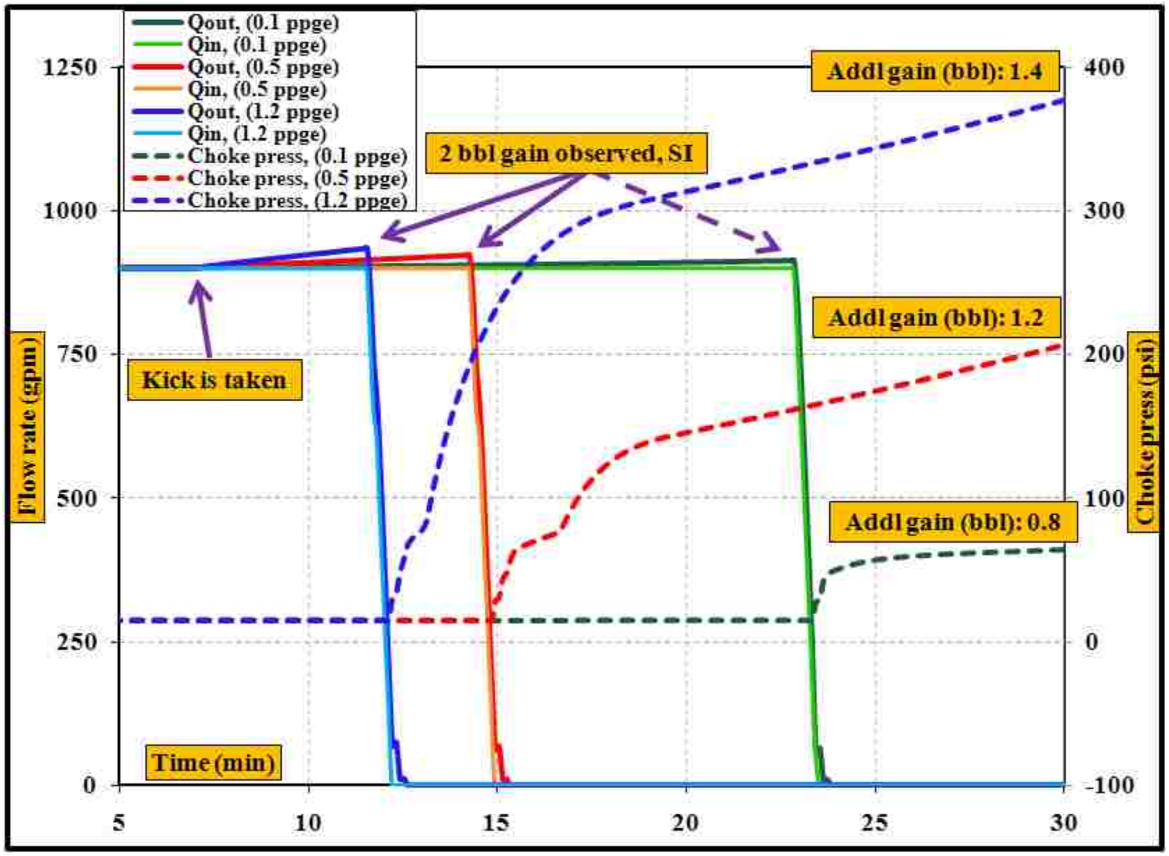
Initial response	Permeability	Initial gain	Circ UB @ 900 gpm	Case code	Page
Non-Circ	High k	2 bbl	0.1 ppge	C25	189
			0.5 ppge	C26	189
			1.2 ppge	C27	189
		20 bbl	0.1 ppge	C28	189
			0.5 ppge	C29	189
			1.2 ppge	C30	189
	Low k	2 bbl	0.1 ppge	C31	190
			0.5 ppge	C32	190
			1.2 ppge	C33	190
		20 bbl	0.1 ppge	C34	190
			0.5 ppge	C35	190
			1.2 ppge	C36	190
Circ	High k	2 bbl	0.1 ppge	C37	191
			0.5 ppge	C38	192
			1.2 ppge	C39	193
		20 bbl	0.1 ppge	C40	194
			0.5 ppge	C41	195
			1.2 ppge	C42	196
	Low k	2 bbl	0.1 ppge	C43	197
			0.5 ppge	C44	198
			1.2 ppge	C45	199
		20 bbl	0.1 ppge	C46	200
			0.5 ppge	C47	201
			1.2 ppge	C48	202



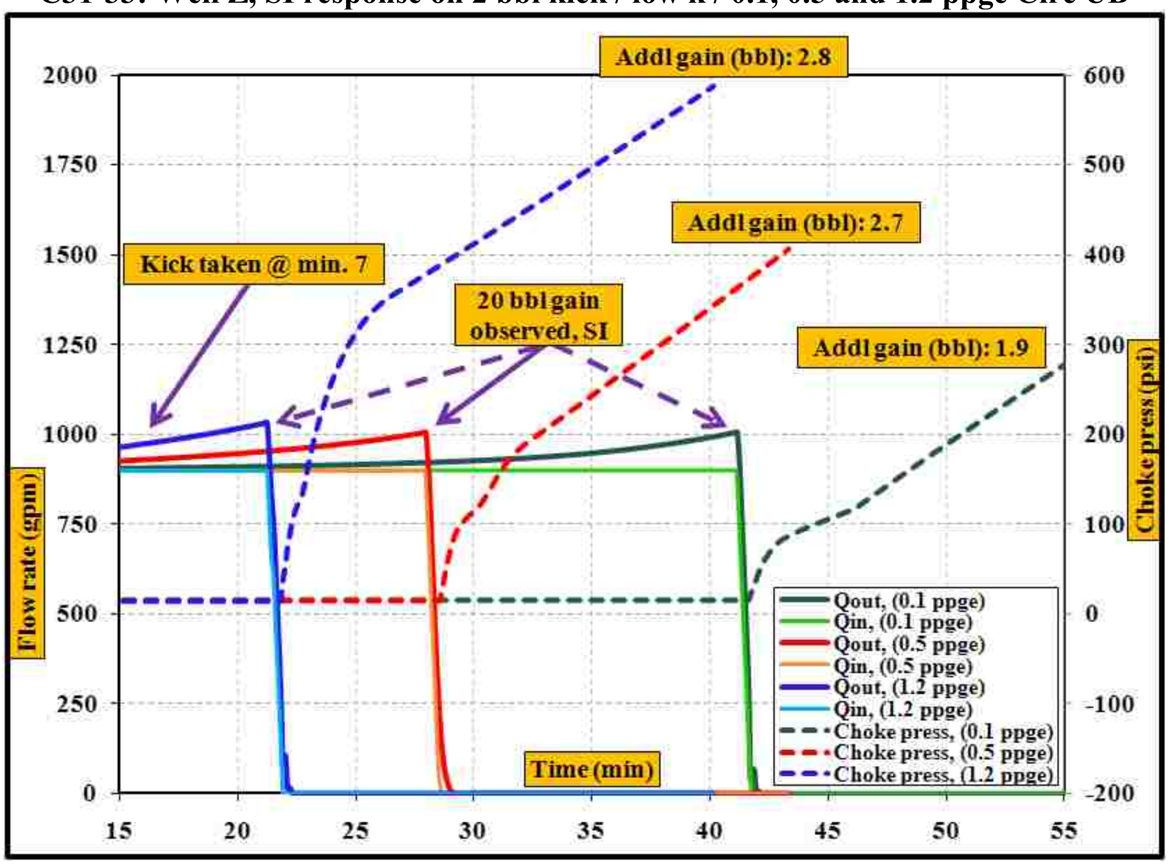
C25-27: Well Z, SI response on 2 bbl kick / high k / 0.1, 0.5 and 1.2 ppge Circ UB



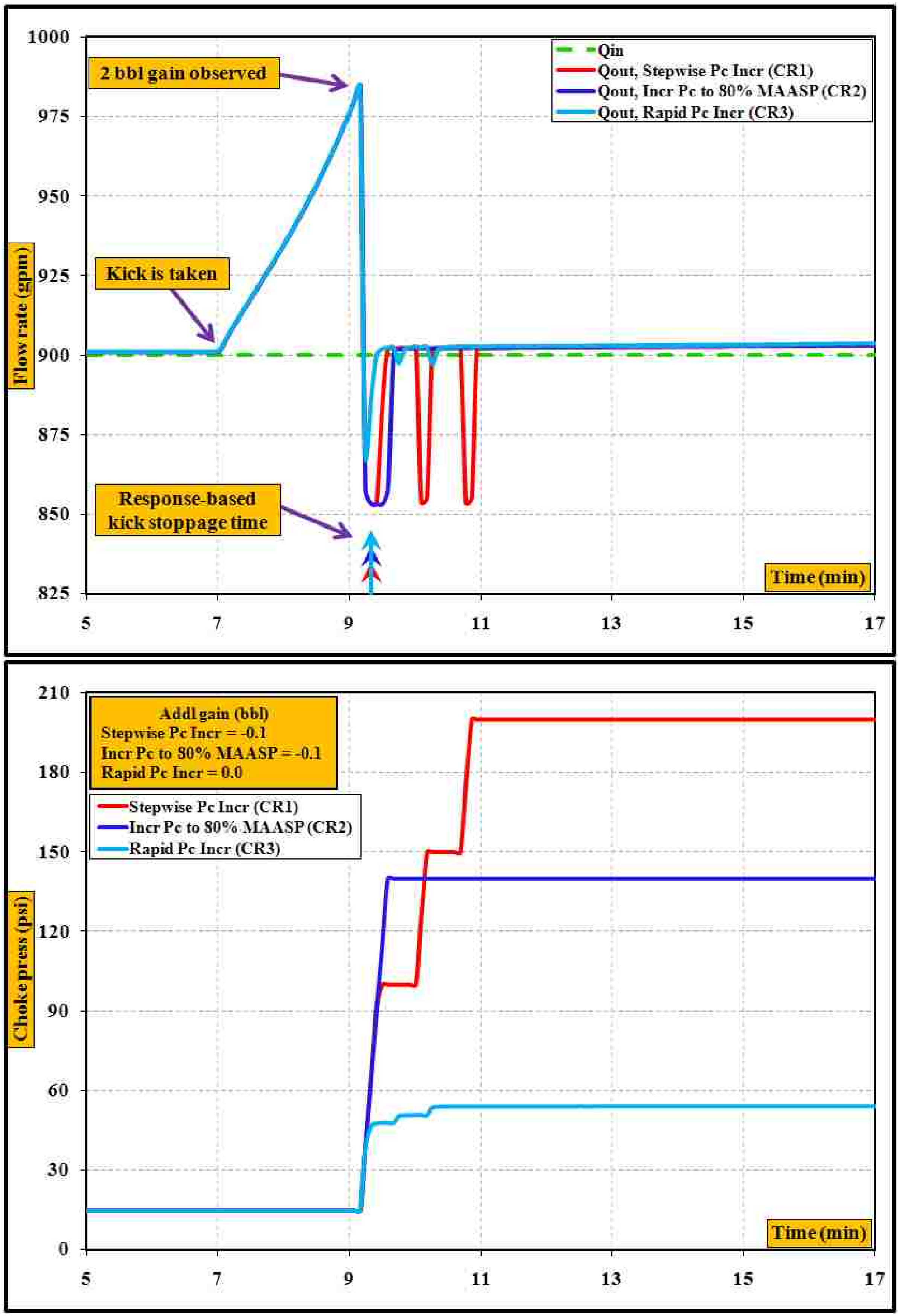
C28-30: Well Z, SI response on 20 bbl kick / high k / 0.1, 0.5 and 1.2 ppge Circ UB



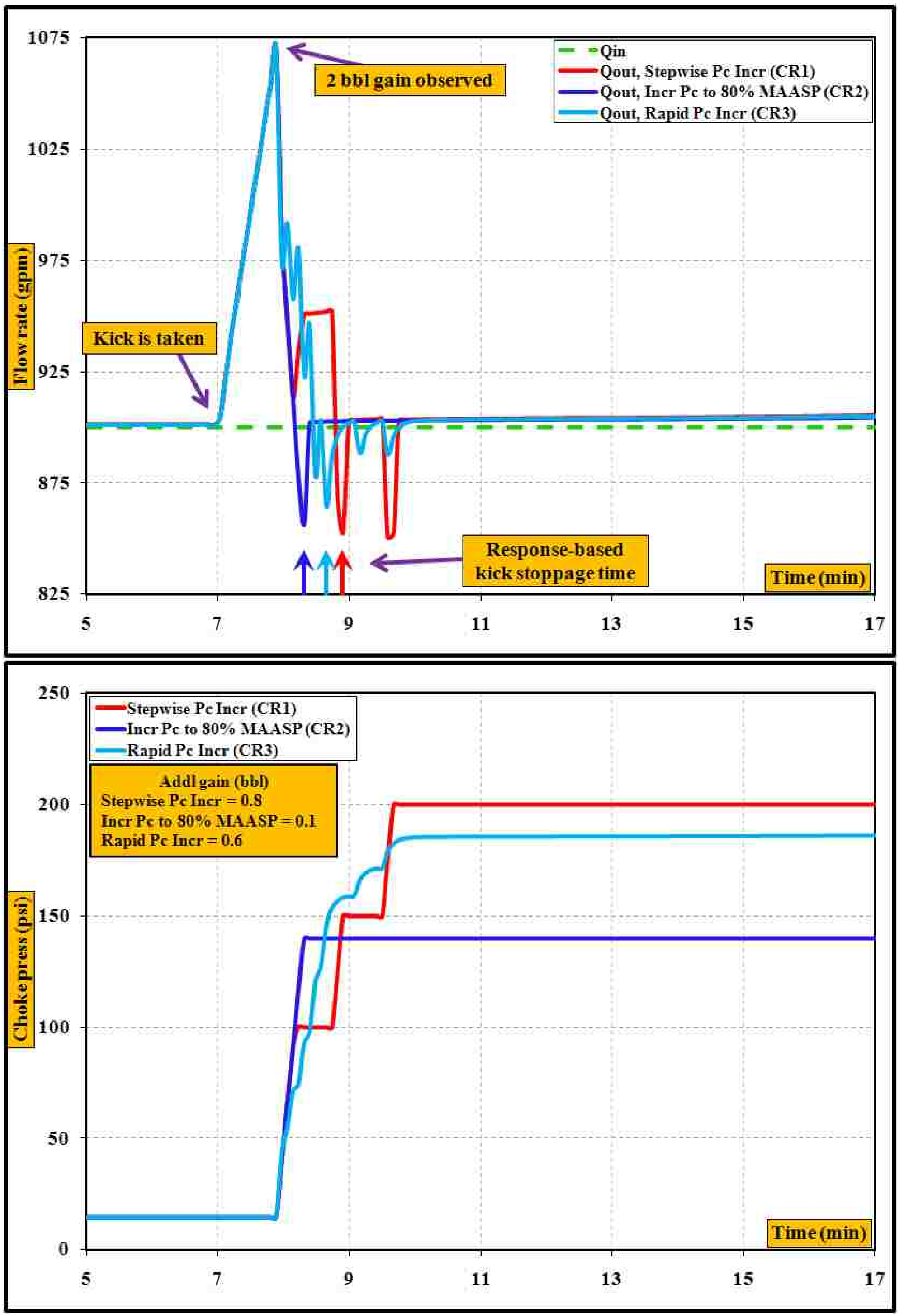
C31-33: Well Z, SI response on 2 bbl kick / low k / 0.1, 0.5 and 1.2 ppge Circ UB



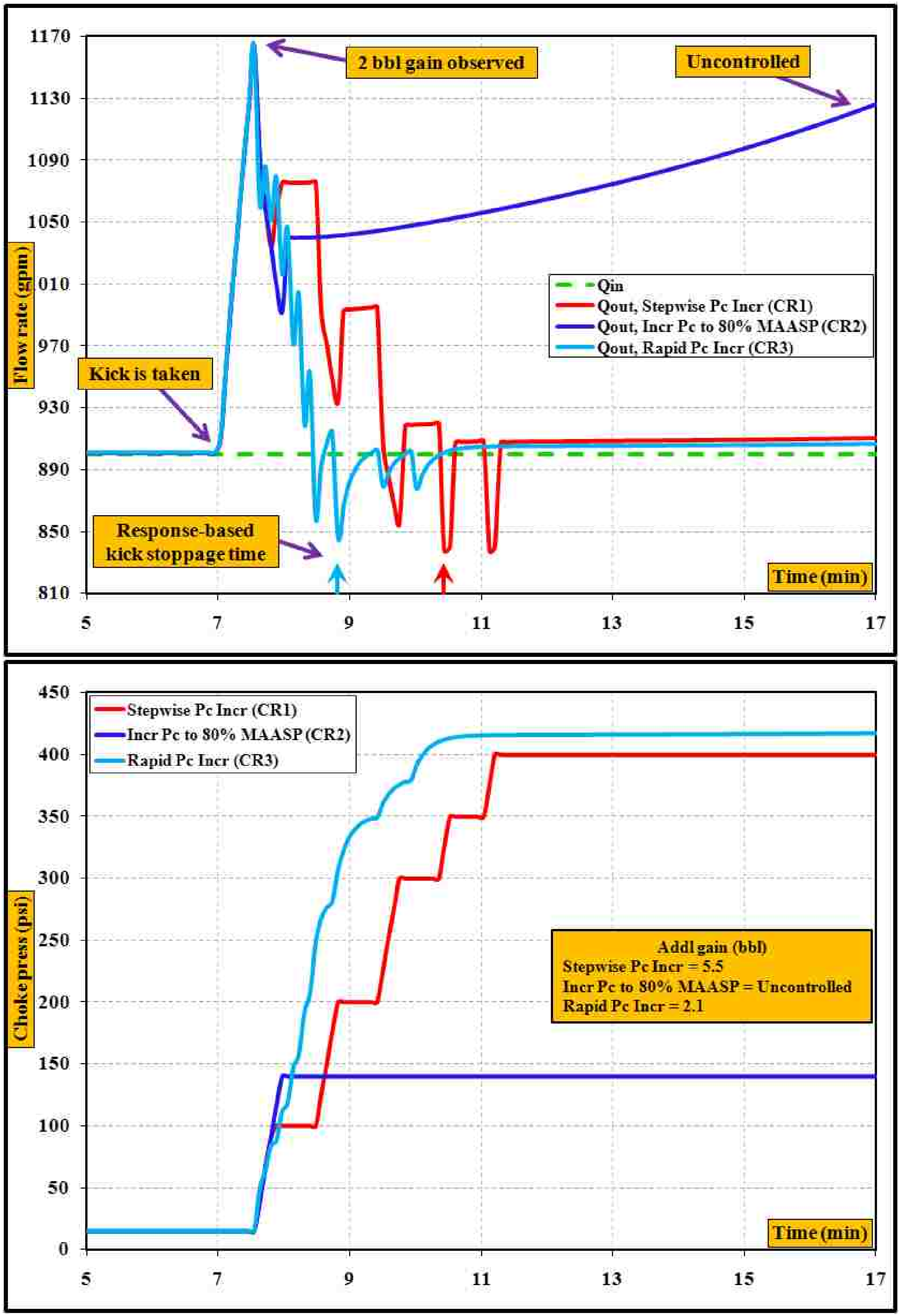
C34-36: Well Z, SI response on 20 bbl kick / low k / 0.1, 0.5 and 1.2 ppge Circ UB



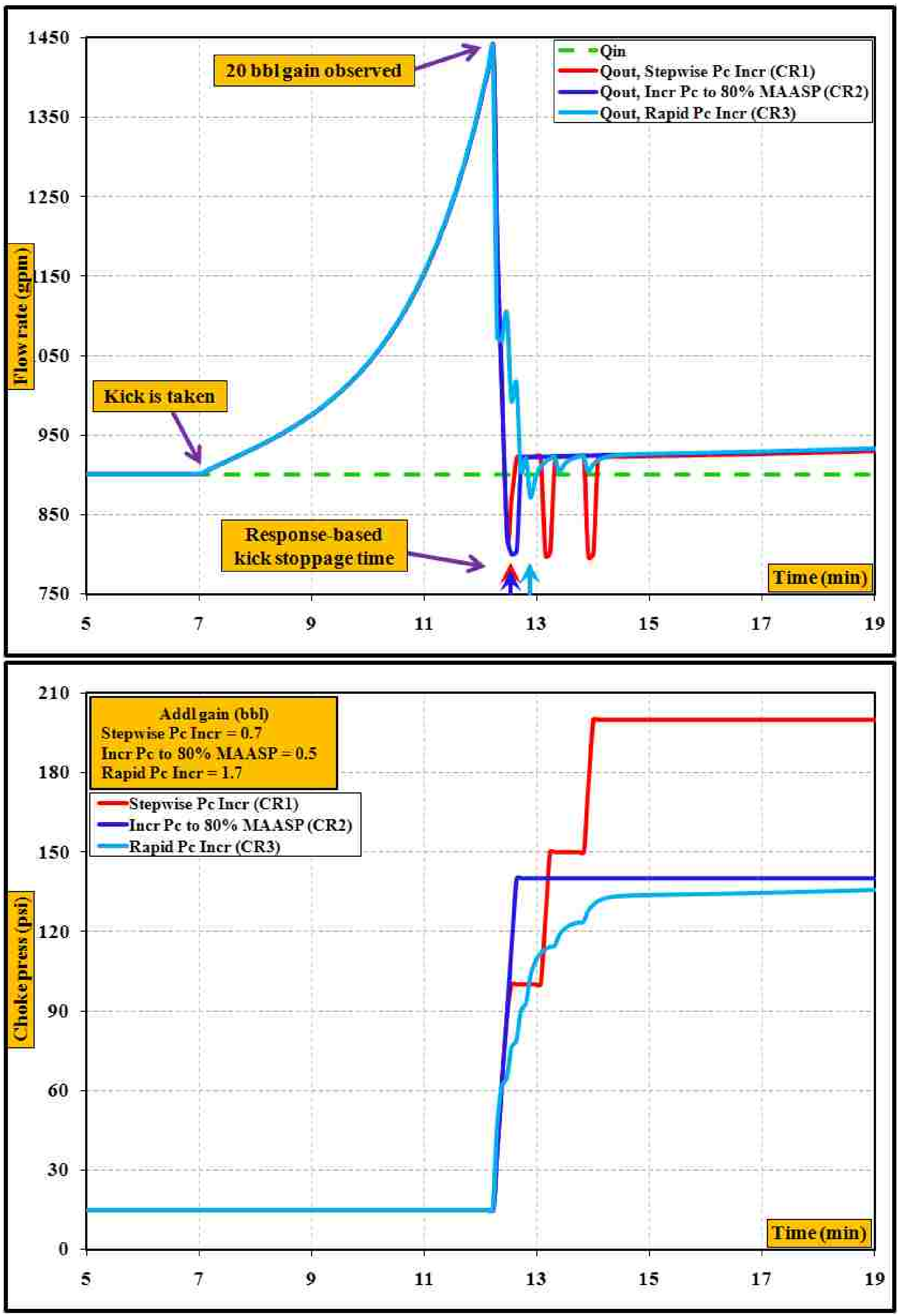
C37: Well Z, application of CRs on 2 bbl kick / high k / 0.1 ppge Circ UB



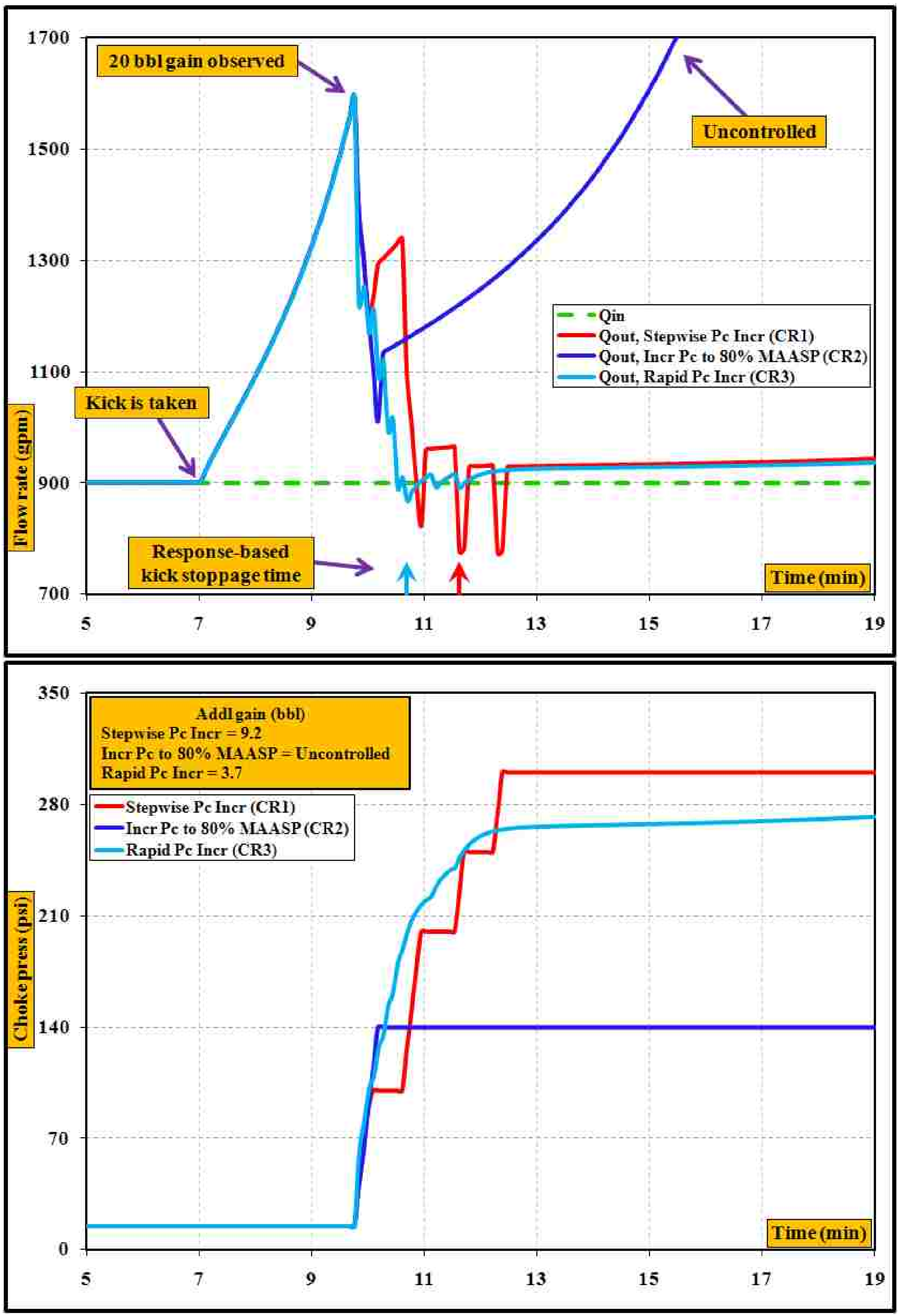
C38: Well Z, application of CRs on 2 bbl kick / high k / 0.5 ppge Circ UB



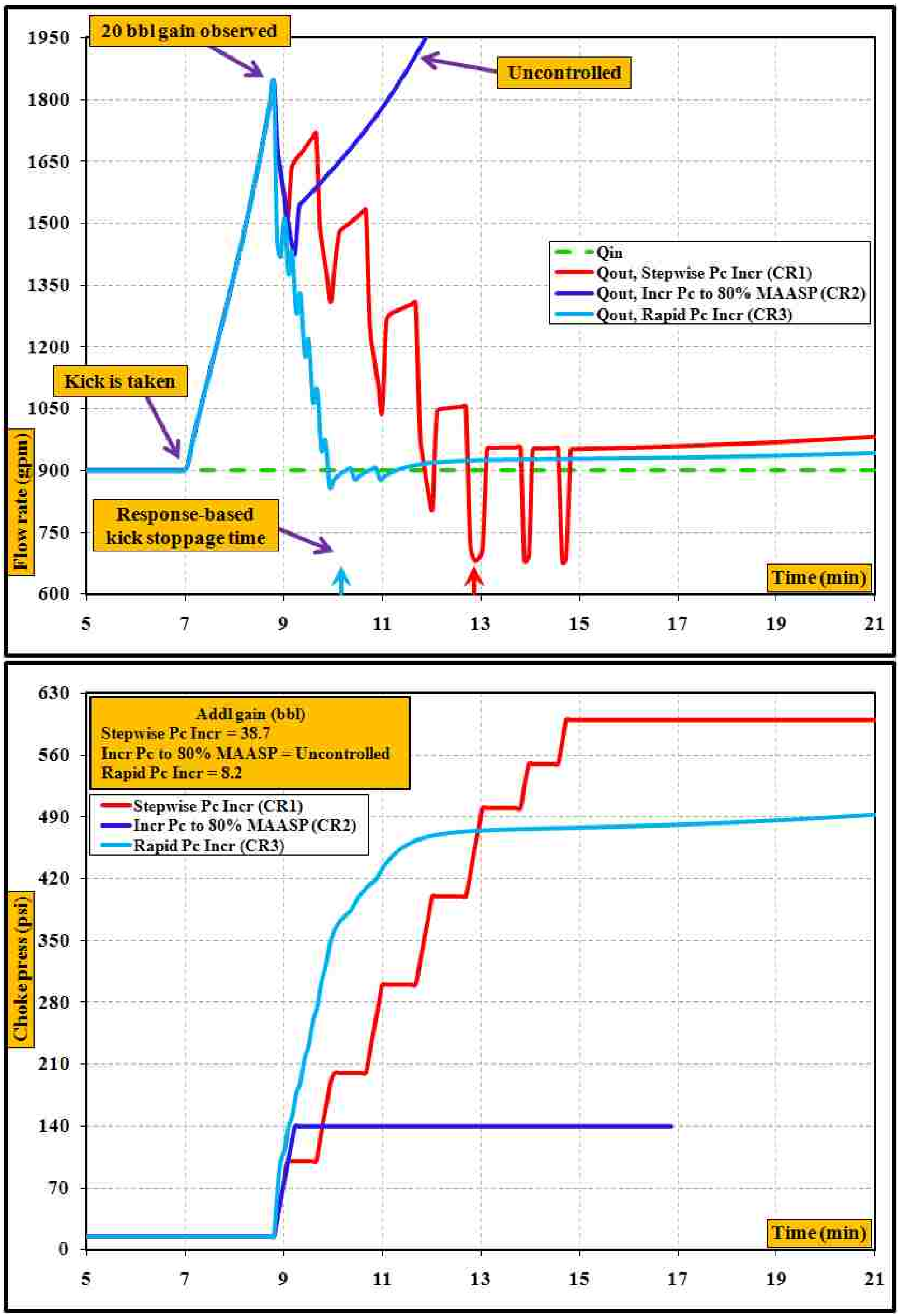
C39: Well Z, application of CRs on 2 bbl kick / high k / 1.2 ppge Circ UB



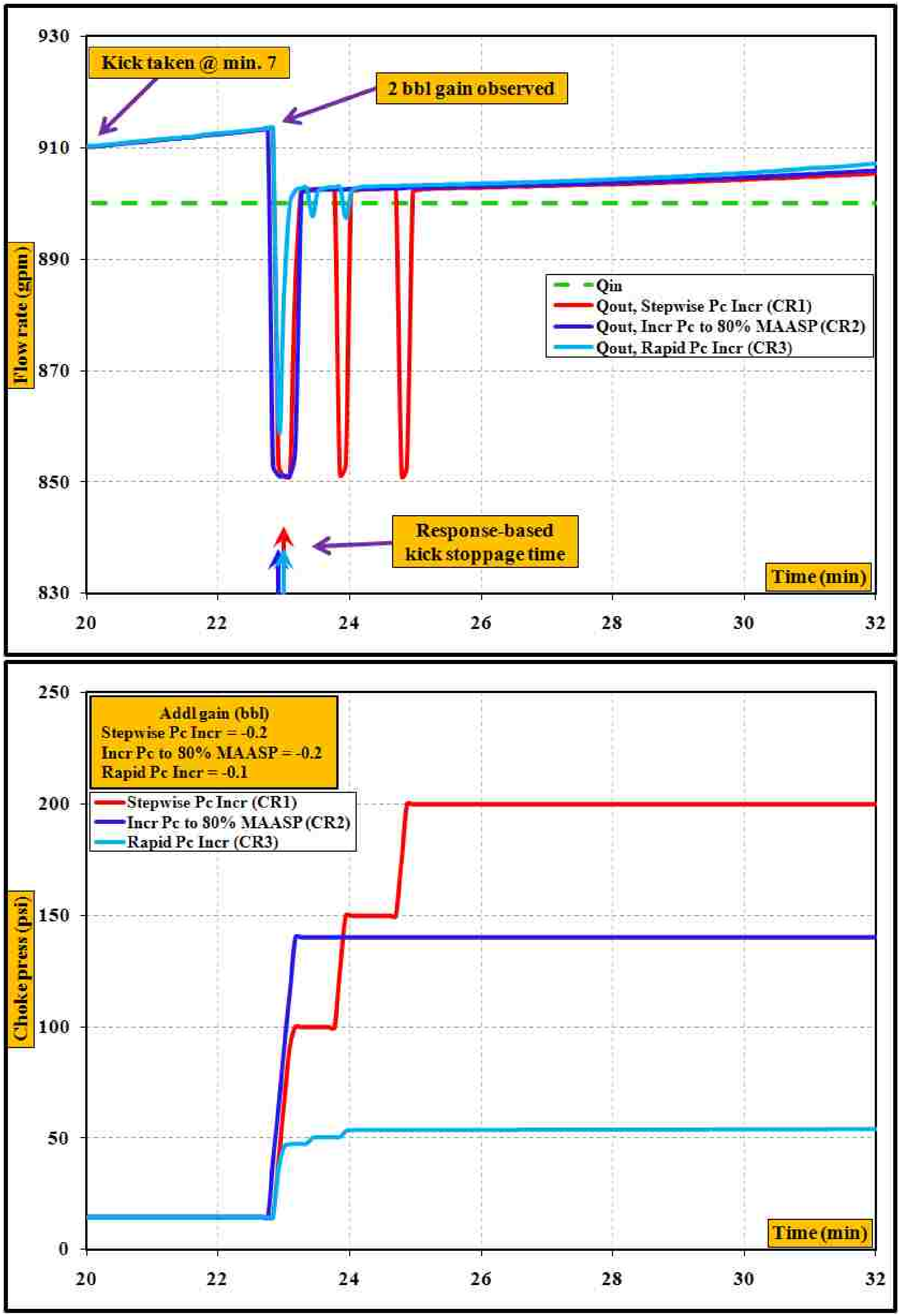
C40: Well Z, application of CRs on 20 bbl kick / high k / 0.1 ppge Circ UB



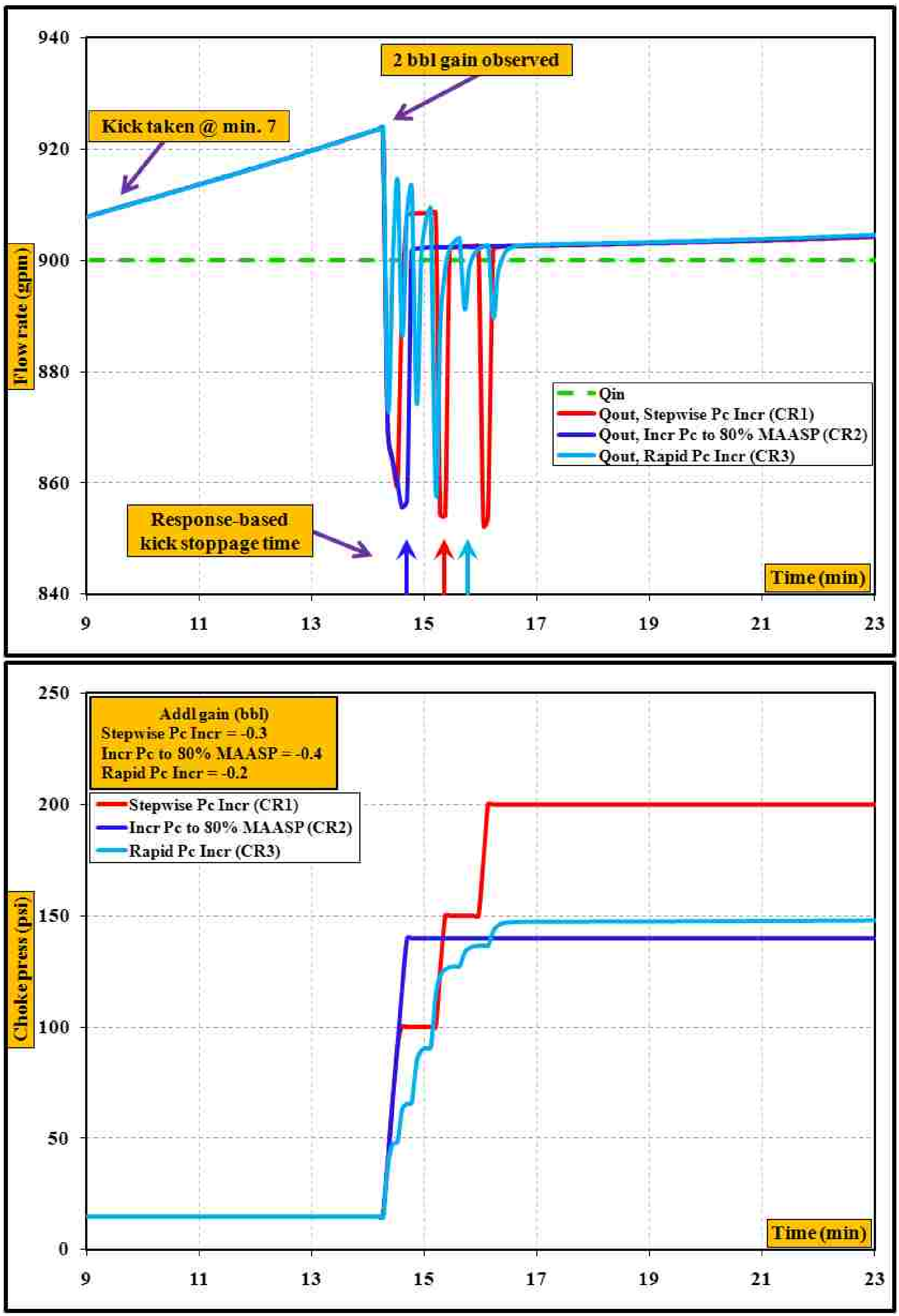
C41: Well Z, application of CRs on 20 bbl kick / high k / 0.5 ppge Circ UB



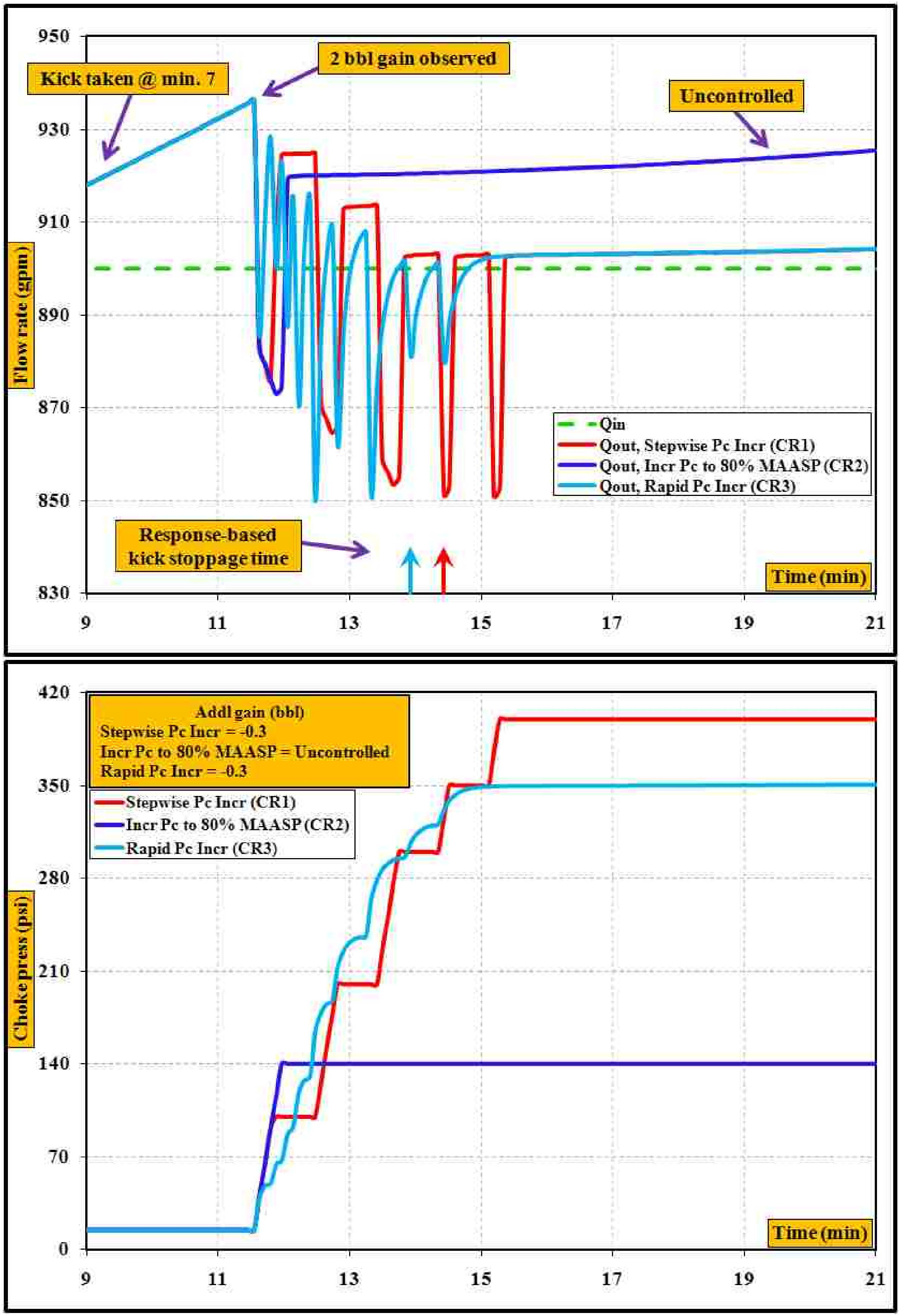
C42: Well Z, application of CRs on 20 bbl kick / high k / 1.2 ppge Circ UB



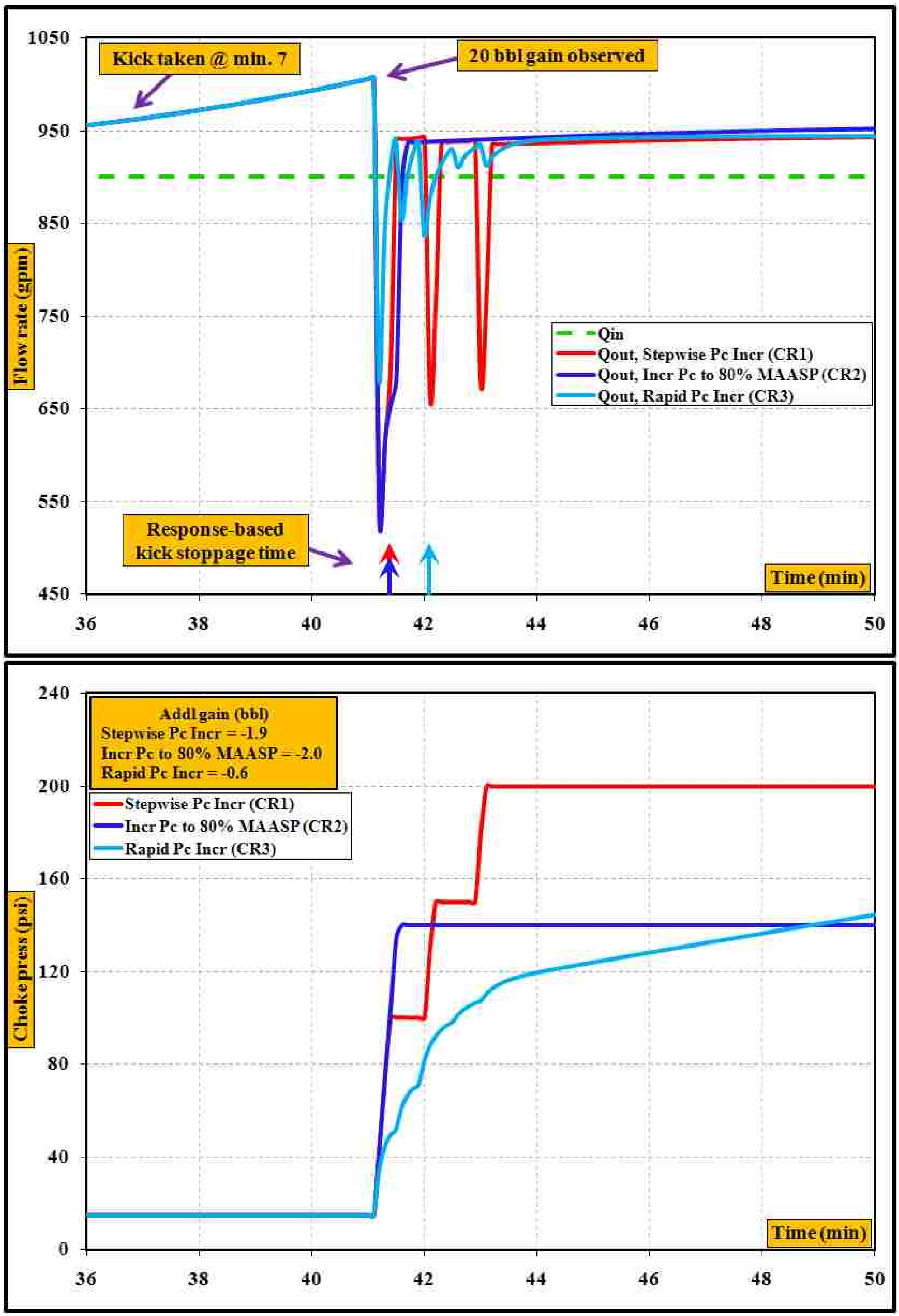
C43: Well Z, application of CRs on 2 bbl kick / low k / 0.1 ppge Circ UB



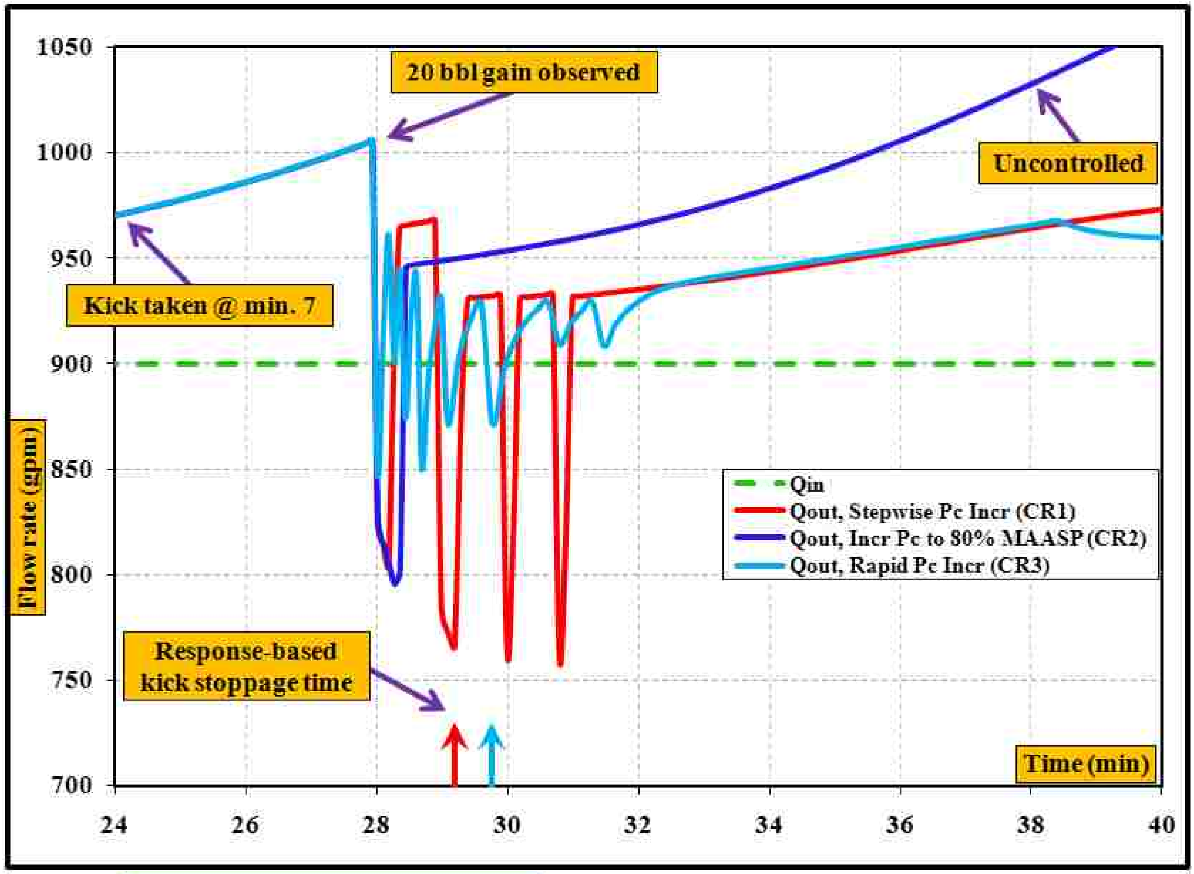
C44: Well Z, application of CRs on 2 bbl kick / low k / 0.5 ppge Circ UB

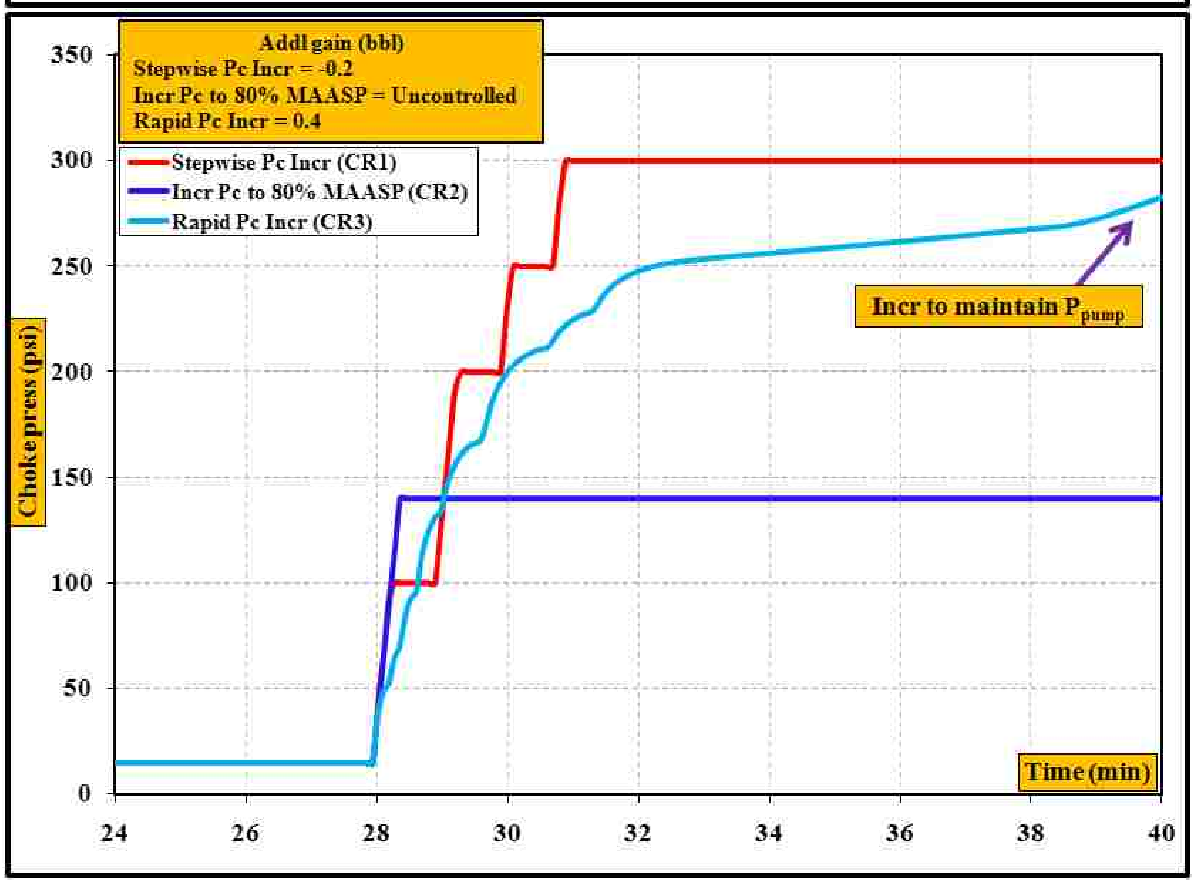


C45: Well Z, application of CRs on 2 bbl kick / low k / 1.2 ppge Circ UB

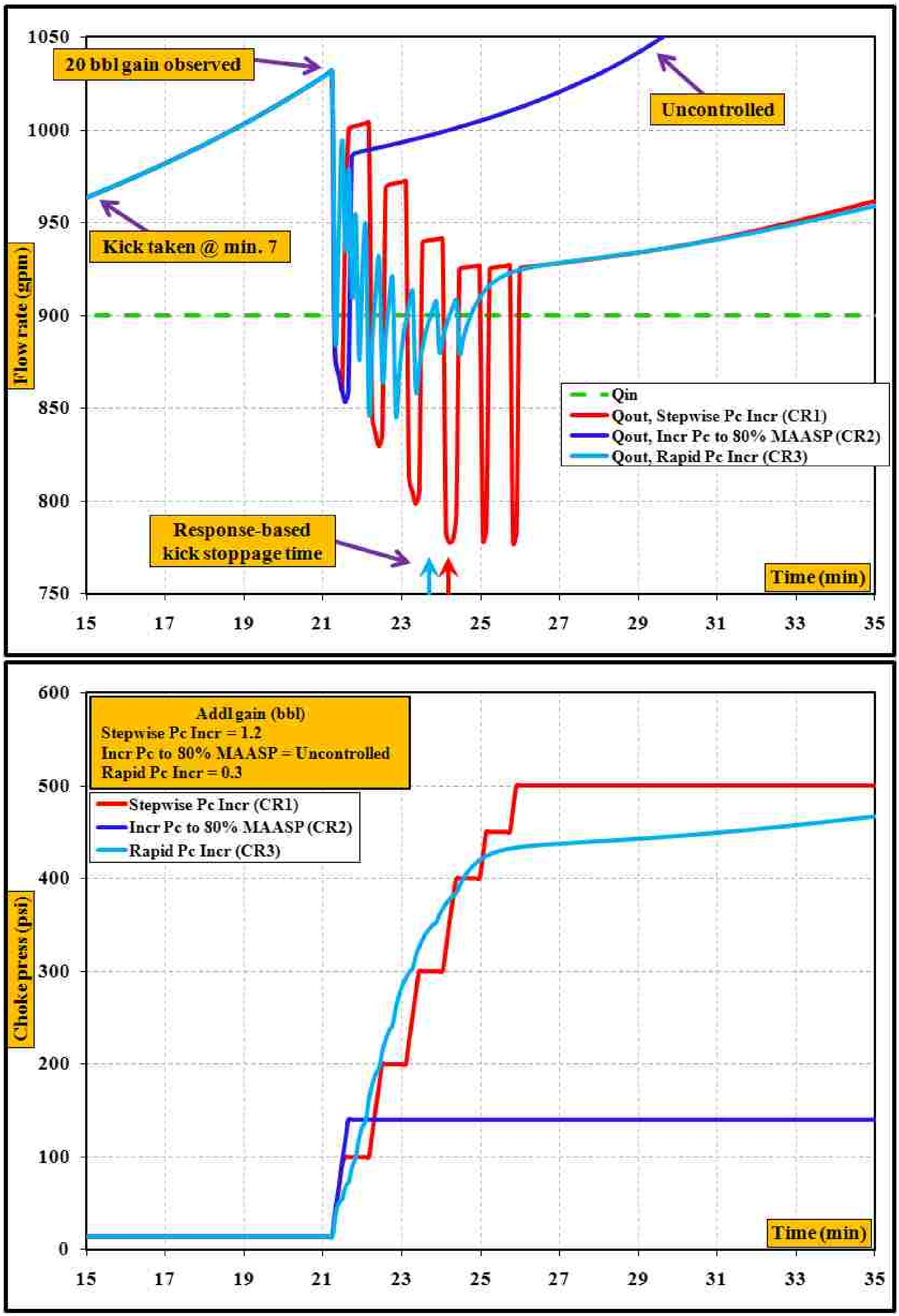


C46: Well Z, application of CRs on 20 bbl kick / low k / 0.1 ppge Circ UB



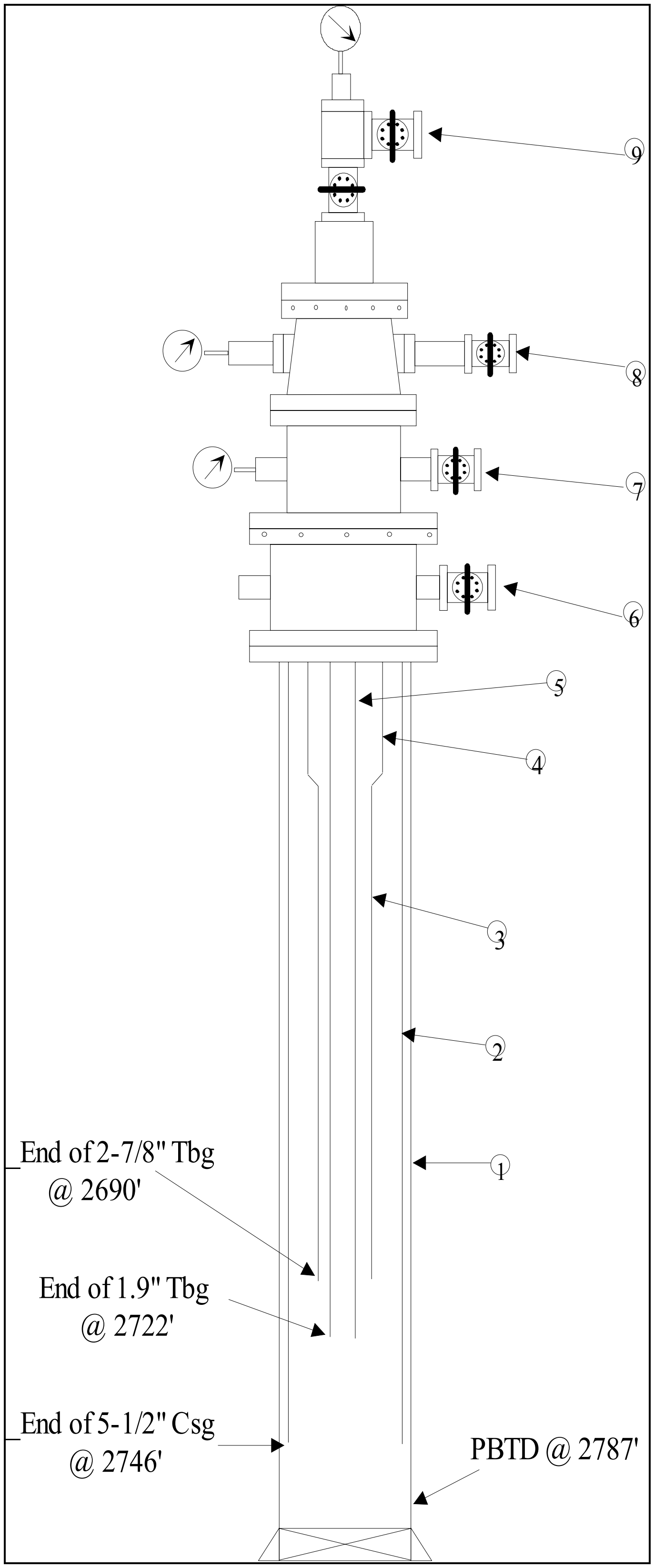


C47: Well Z, application of CRs on 20 bbl kick / low k / 0.5 ppge Circ UB

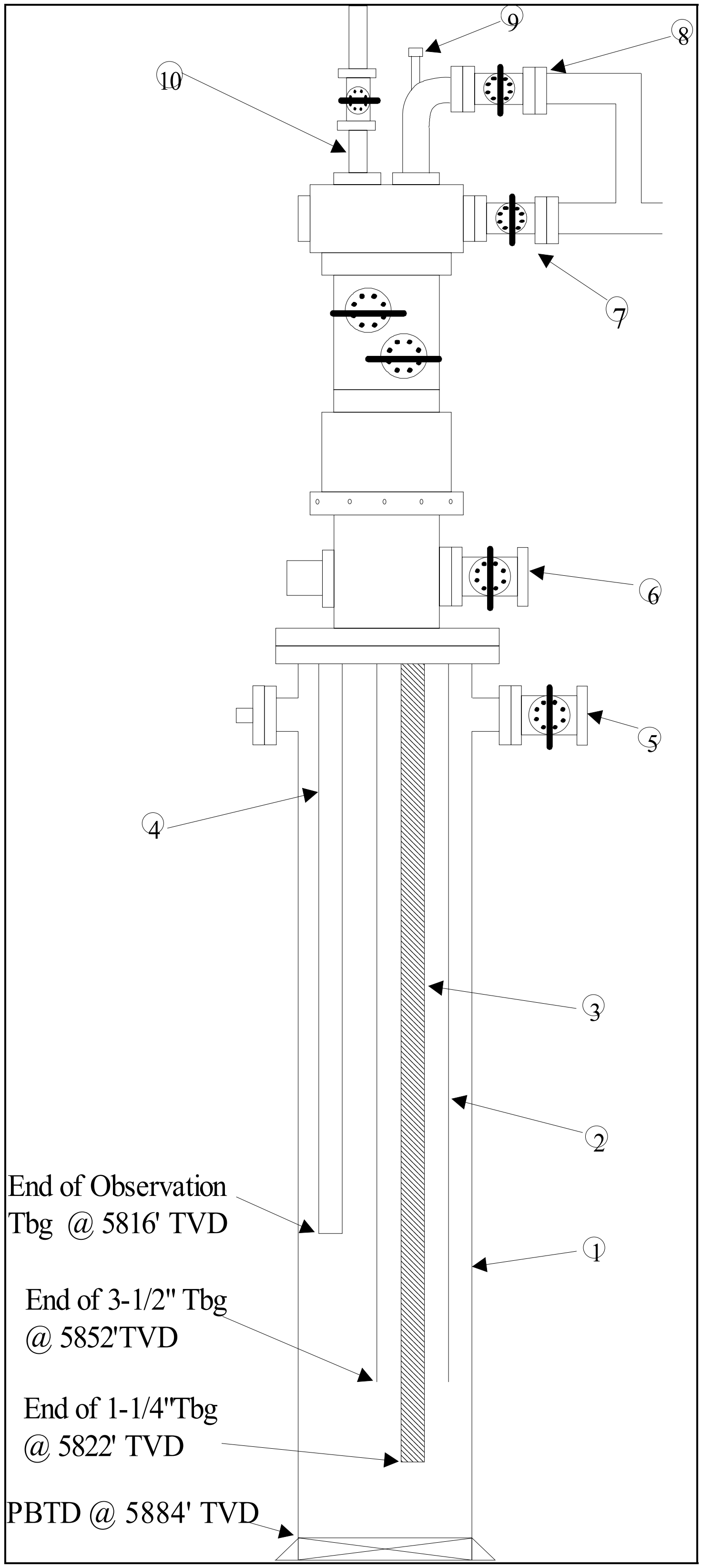


C48: Well Z, application of CRs on 20 bbl kick / low k / 1.2 ppge Circ UB

APPENDIX D: SCHEMATIC OF LSU WELL NO. 1



APPENDIX E: SCHEMATIC OF LSU WELL NO. 2



APPENDIX F: AT BALANCE™ PERMISSION LETTER

Date: 03-Nov-2009

Majid Davoudi
Department of Petroleum Engineering
Louisiana State University
3516 Patrick T. Hall
Baton Rouge, LA 70803-6417

Subject: Permission to Use MPD Equipment Images

Dear Mr. Davoudi:

Your work as a graduate student doing research for the LSU MPD consortium since 2007 was explicitly intended to provide mutual benefit to At Balance™ and to you by providing an opportunity to complete your Master's thesis at Louisiana State University. We have reviewed your thesis, A Simulation-Based Evaluation of Alternative Initial Responses to Gas Kicks during Managed Pressure Drilling Operations, and approve your use of all equipment images therein that were provided by At Balance™.

Sincerely,

Philip Frink
VP of Applications and Business Development
At Balance USA, LLC

APPENDIX G: SHELL E & P COMPANY PERMISSION LETTER

Date: 03-Nov-2009

Majid Davoudi
Department of Petroleum Engineering
Louisiana State University
3516 Patrick T. Hall
Baton Rouge, LA 70803-6417

Subject: Permission to Use DAPC System Response for Pipe Connection

Dear Mr. Davoudi:

Your work as a graduate student doing research for the LSU MPD consortium since 2007 was explicitly intended to provide mutual benefit to Shell Exploration and Production Company (SEPCO) and to you by providing an opportunity to complete your Master's thesis at Louisiana State University. We have reviewed your thesis, <u>A Simulation-Based Evaluation of Alternative Initial Responses to Gas Kicks during Managed Pressure Drilling Operations</u>, and approve your use of DAPC system response plot for pipe connection example of well MFWU#84 ST02 shown as Figure 2.8 in your thesis therein that was provided by SEPCO.

Sincerely,

PHILIP VOGELSBERG 11/10/09

VITA

Majid Davoudi was born in Tehran, capital of Iran, in 1972. He received his elementary, guidance and high school education in public schools in Tehran. He was admitted to the Sharif University of Technology and completed his Bachelor of Science in applied physics with minor in atomic physics in 1996. Then he served two years of compulsory military service as second Lieutenant in the Defense Ministry of Iran. Majid was later employed by Tehran branch of Schlumberger oilfield services. He worked six and half years as measurement while drilling (MWD), logging while drilling (LWD) and directional drilling (DD) engineer in Iran, Qatar and Oman. Majid attended several Schlumberger technical and soft skill seminars, but they merely expanded his job related knowledge. To discover other fundamental petroleum engineering horizons, he decided to apply for an academic program. He was accepted by the Craft and Hawkins Department of Petroleum Engineering at Louisiana State University and began his graduate studies in August 2006.

His interests include well design, well control, well completions, directional drilling, underbalanced and managed pressure drilling.