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The Diagnosis of Well Control Complications during Managed Pressure Drilling

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THE DIAGNOSIS OF WELL CONTROL COMPLICATIONS DURING MANAGED PRESSURE DRILLING

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Abstract

The constant bottom-hole pressure method of managed pressure drilling is generally expected to reduce well control risks and apply well understood concepts when a kick is taken. Nevertheless, complications, such as operator error, leaks, plugging, equipment failures, and exceeding kick tolerance, can occur during kick circulation. By not properly interpreting the symptoms of a complication, a driller risks the consequences of additional influx, lost circulation or the simultaneous occurrence of both. To address the challenge of diagnosing complications, the implied pit gain (IPG) method is being evaluated as an enhancement to established industry practices.

Traditional diagnostic methods attempt to match qualitative assessments of changes in the behavior of surface pressures, e.g. pump pressure and choke pressure, to particular complications. Under these circumstances, the interpretation of the onset of a complication may be subjective in nature and vary between individuals. By only evaluating changes in surface pressure, rig personnel may not be informed of the consequences of a given complication. Finally, previously published diagnostic strategies do not incorporate a structured approach for determining when kick tolerance has been exceeded.

IPG is based on the concept that changes in surface pressures can be quantitatively linked to changes in pit gain with reasonable accuracy throughout the duration of a complication-free kick circulation. As a result, when these surface indicators deviate from a range of predicted behavior, one can objectively conclude that a complication is occurring. Research has been performed to demonstrate that the profile of the surface indicators, when deviating from predicted trends, contain unique attributes that can facilitate the diagnosis of a complication. Furthermore, quantifying the relationship between changes in surface pressure and pit gain over time provides data

that can be used to assess the consequence of a given complication. Such knowledge may be used to facilitate effective field-based decisions or programming for intelligent systems to provide a correct response.

1 Introduction

1.1 Research Objective

The objective of the research described in this thesis is to evaluate the utility of the implied pit gain (IPG) method as a tool to diagnose complications that occur while conducting well control operations during managed pressure drilling (MPD) or when using the driller's method. IPG is based on the concept that changes in surface pressure are dependent on changes in pit gain. Thus, changes in surface pressures with regard to changes in pit gain can be quantitatively predicted within a reasonable range of accuracy throughout the duration of a complication-free, constant pump pressure kick circulation.

Four specific questions were addressed to fulfill this objective. The first is whether an IPG complication-free prediction can be made successfully. The second is whether IPG can be applied for early identification of the occurrence of a complication. The third is whether or not the behavioral profile of the deviation between actual and predicted behaviors can be utilized to diagnose the complication. Finally, the value of the IPG method will be weighed against traditional diagnostic methods currently practiced by the drilling industry to determine whether it has any additional advantages to those methods.

The complications simulated include plugging and leaks in the surface equipment, drill string, and annulus, operator error in choke control, and events where kick tolerance has been exceeded. The consequences of such complications can result in lost circulation, additional influx of formation fluids, simultaneous downhole losses and influx, or simply a sustained undesirable change in wellbore pressure.

1.2 LSU MPD Consortium Research Objectives

A consortium including LSU and industry representatives interested in MPD operations was initiated in 2006. The overall objective of the consortium is to establish a basis for 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 constant bottom-hole pressure (CBHP) method of MPD. (Davoudi, 2009)

2 Constant Bottom-Hole Pressure Method of MPD Overview

2.1 Conventional Drilling

In conventional drilling operations, drilling fluid is circulated down the drill string and out of the wellbore through an open flow line above the blowout preventer (BOP). As a result, the annulus is exposed to atmospheric pressure. During such operations, wellbore pressure is most commonly controlled by adjusting the density and viscosity of a drilling fluid, pump rate and cuttings load by adjusting the rate of penetration (ROP). In doing so, a drilling engineer can adjust annular circulating friction and hydrostatic pressure to allow for the wellbore to remain between pore and fracture pressure. Wellbore pressure should be kept high enough to maintain well control and wellbore stability and low enough to avoid lost circulation, reduce stuck pipe events, and prevent inefficiencies in bit performance. Satisfying these constraints keeps wellbore pressure in an optimized range while drilling.

Equation 1: $\mathrm{P}_{\text{formation}} < \mathrm{P}_{\text{stability}} < \mathrm{P}_{\text{wellbore}} < \mathrm{P}_{\text{inefficient ROP \& stuck pipe}} < \mathrm{P}_{\text{fracture}}$

Since adjusting fluid properties requires time and effort, conventional drilling operations have a limited capacity to address dynamic operational challenges that are the result of known and unpredictable wellbore conditions. As a result, unexpected influxes, lost circulation, and stuck pipe can cause significant non-productive time (NPT) during drilling operations.

In the event of an influx, traditional well control methods require time to perform a pump shut down, possibly perform a flow check, and finally shut-in the BOP (Bourgoyne, Chenevert, Millheim, & Young, 2005). During these procedures, bottom-hole pressure (BHP) falls due to a loss in circulating friction and the well continues to take additional influx until the BOP is finally shut-in. Despite the drop in BHP and time needed to execute the above operations, the conventional method is robust in terms of the ease in which rig personnel can be trained to execute these operations.

2.2 Underbalanced Drilling

Excessive skin damage to productive zones often caused by highly overbalanced wellbore pressures can limit reservoir productivity and reduce ROP during drilling. As a result, a closed style drilling system, known as underbalanced drilling (UBD) was developed where wellbore pressure could remain underbalanced during drilling operations. Such a system can permit the simultaneous production of formation fluid while drilling. Underbalanced conditions can help reduce skin damage which improves reservoir productivity and improve bit performance which increases penetration rates. (Rafique, 2008)

In order to conduct UBD, a rotating control device (RCD) is used to seal in the annulus around a drill string while penetrating the formation. The RCD is positioned above the BOP. A flow line from the RCD serves as a conduit for returns to a designated choke system and separation system. The intentionally produced hydrocarbons are flared or sent to production facilities. Furthermore, the annulus is a closed system. (Rafique, 2008)

While having some advantages, drilling underbalanced may be unsuccessful in hole sections where formation productivity is high, pore pressures estimates have significant uncertainty, or there is a potential for H_2S. (Ostroot, Shayegi, Lewis, & Lovorn, 2007)

2.3 Managed Pressure Drilling

Managed pressure drilling (MPD) is a methodology of drilling that is derived from UBD with the key difference being that drilling operations are designed to remain slightly overbalanced. The International Association of Drilling Contractors defines MPD as “an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to manage the annular hydraulic pressure profile accordingly.” (Hannegan, 2005)

As with UBD, MPD deploys a RCD to seal in the annulus around the drill pipe during drilling operations while diverting flow to a designated MPD choke system. MPD is often supported with the use of flow meters to accurately measure flow rates in and out of the wellbore as another indicator of wellbore conditions. (Vieira & Arnone, 2009) Precise control of the wellbore pressure profile in MPD can help reduce the risk of influx, lost circulation, and stuck pipe. Reducing the risk of such hazards can also allow one to set fewer casing strings. Additionally, since drilling operations are overbalanced, the health safety and environmental concerns of continuously and intentionally producing formation fluids while drilling are eliminated.

The most common forms of MPD are the constant bottom-hole pressure method (CBHP), pressurized mud-cap drilling (PMCD), and dual gradient drilling (DGD). This research will focus mainly on the diagnosis of well control complications while deploying the CBHP method of MPD. Thus, DGD and PMCD will not be discussed.

2.4 Constant Bottom-Hole Pressure Method while Drilling

The objective of the CBHP method of MPD is to select and maintain a target wellbore pressure via the management of back pressure and annular circulating friction. While called the Constant Bottom-Hole Pressure Method, this method can be used to keep pressure at any one desired point in the wellbore constant. CBHP can be managed by adjusting the amount of back pressure applied by the MPD choke, changing drilling fluid density and cuttings load to adjust hydrostatic pressure and modifying fluid rheology, pump rate, and drill string rotational velocity to control annular circulating friction. Equation 2 represents the factors that contribute to wellbore pressure in a mathematical fashion.

Equation 2: $\mathrm{P_{wellbore}} = \mathrm{P_{back\ pressure}} + \mathrm{P_{annular\ friction}} + \mathrm{P_{hydrostatic}}$

2.4.1 Managing Wellbore Pressure

The application of back pressure can be induced by modifying the restriction of flow out of the annulus by adjusting the MPD choke opening. The pressure remains trapped due to the use of a Rotating Control Head (RCD). The application of back pressure is a dynamic form of pressure management that can be deployed as part of drilling or well control operations.

The management of annular circulating friction and hydrostatic pressure can be achieved by modifying fluid rheology and density, pump rate, penetration rate (cuttings load) and drill string rotational velocity to achieve a target wellbore pressure. Changes in fluid rheology and density often require the time needed to mix drilling fluid with different properties to achieve desired properties. Higher density, viscosity fluids and pump rate typically yield higher frictional pressure losses. The converse is also true. Finally, high drill string rotational speeds induce additional turbulence which may cause circulating friction to increase as well.

The CBHP method allows an operator to dynamically maintain wellbore pressure within an optimal range. An ideal wellbore pressure is one that is between pore and fracture pressure margins as well as high enough to maintain wellbore stability and low enough to prevent stuck pipe and ensure efficient ROP as noted in Equation 1. Precise control of wellbore pressure in this manner can help reduce the risk of influx, lost circulation and stuck pipe, which represent 33% of the NPT in the Gulf of Mexico (Minerals Management Service, 2008). Also dynamic pressure control strategies allow a drilling crew to optimize wellbore pressure without the downtime attributed to re-mixing and re-circulating drilling fluid multiple times. Finer control of wellbore pressure may permit one to set fewer casing strings, especially in offshore environments where the margins between pore and fracture pressure are more narrow.

2.4.2 Maintaining CBHP while Changing Flow Rates

The CBHP method can be implemented through the use of MPD pump start-up and shut-down schedules as well as continuous circulating systems. The objective of these systems is to maintain a constant BHP during events marked with significant changes in mud pump flow rate. A common example is tripping operations where the mud pumps are traditionally shut down. Under such circumstances, wellbore pressure can fall from the loss in circulating friction and an unexpected influx could be taken. However, in the CBHP method, continuous circulation systems or MPD pump start-up and pump shut-down schedules can be deployed to keep wellbore pressure relatively constant during tripping. Continuous circulation systems allow tripping to take place with the pump running. MPD pump start-up and pump shut-down schedules allow the well to trap pressure in the annulus to offset the loss in circulating friction.

MPD pump start-up and pump shut-down schedules create a synchronized schedule of varying casing pressure to offset a gain or loss in wellbore pressure with a change in pump rates. For example, during a pump shut-down, the pressure lost in the wellbore from stopping circulation would be trapped in the wellbore with the MPD choke and RCD. Alternatively, a small back pressure pump can be utilized to facilitate achieving the necessary back pressure. Conversely, during a pump start-up, trapped pressure in the annulus can be reduced to offset the increase in wellbore pressure from circulating once again. (Guner, 2009)

The industry has also produced a variety of continuous circulating systems. These systems allow drilling fluid circulation to continue while making or breaking drill pipe connections through a variety of different strategies. In addition to preventing a drop in wellbore pressure that may cause an influx during tripping, these systems also intend to reduce NPT due to cuttings settling. (Weir, Goodwin, & Macmillan, 2012)

2.5 Constant Bottom-Hole Pressure during Well Control

Two different well control responses are generally applicable in the event of an unexpected influx during CBHP operations. The first and most commonly deployed well control strategy is the traditional approach, consisting of shutting-in with the BOP followed by circulation with the driller’s method or the wait and weight method. The second strategy involves stopping an influx by rapidly increasing wellbore pressure with the MPD choke and circulating out the influx using the first stage of the driller’s method. (Das, 2007)

2.5.1 Traditional Shut-in with BOP

The pump shut down, flow check, and BOP shut-in followed by a kick circulation with the driller’s method or the wait and weight method is still the most common form of well control. In either method, drilling fluid is circulated down the drill string, up the annulus and diverted through a flow line in the BOP to a designated rig choke while maintaining BHP constant and slightly above formation pressure. (Roy, Nini, Sonnemann, & Gillis, 2007)

The rig choke size is manipulated to maintain a constant bottom-hole pressure while permitting a gas influx to safely expand while approaching the surface in either the driller’s or the wait and weight methods. Allowing an influx to expand while approaching the surface prevents pressures that may be as high as formation pressure from being directly contained by the weak zone, casing, and surface equipment as an influx approaches the surface. As gas expands, drilling fluid is displaced from the wellbore causing a loss in hydrostatic pressure. Offsetting the loss in hydrostatic pressure with additional choke pressure prevents wellbore pressure from falling while the influx displaces drilling fluid during expansion. As a result, wellbore pressure at a given depth can remain constant. (Roy, Nini, Sonnemann, & Gillis, 2007)

2.5.2 Rapid Choke Pressure Increase - Well Control Response

MPD experts in the industry are also proposing the rapid choke pressure increase well control response as means of controlling an influx without the time needed to perform a pump shut down, flow check and BOP shut-in. In order to do so, an influx is detected when the flow out of the annulus unexpectedly exceeds the flow injected into the wellbore by the mud pumps. The increased flow rate is due to the fact the drilling fluid from the mud pumps and formation fluid are both being injected into the annulus simultaneously. Once the influx is detected, the drilling crew relies upon the RCD to contain pressure within the annulus while a designated MPD choke is used to increase wellbore pressure high enough to restrict flow out equal to flow in, thereby stopping an influx, and allowing a CBHP kick circulation to begin.(Das, 2007)

The MPD choke manifold is used to circulate the influx out of the wellbore while maintaining a constant wellbore pressure by following the first stage of the driller's method, upon confirmation that flow rates are once again equal to one another. Thus, the influx is allowed to safely expand during circulation while choke pressure is applied to offset any loss in hydrostatic pressure and maintain a constant BHP. (Das, 2007)

This research will focus primarily on well control complications in the context of the CBHP kick circulations during MPD. However, one may also apply this work to the driller's method during conventional drilling operations.

3 Literature Review

3.1 Origin of Implied Pit Gain Method (Barbato et al, 2007)

The implied pit gain method, first envisioned by Darryl Bourgoyne at Louisiana State University, is an idea targeted at developing a diagnostic method for well control complications. IPG is based on fundamental petroleum engineering principles that allow one to predict the behavior of pump pressure, choke pressure, and pit gain throughout a successful CBHP circulation of a gas kick. As a result, IPG also suggests that any deviation from the predicted values of surface indicators, e.g. pump pressure, choke pressure or pit gain, implies that a complication may be occurring. (Barbato, Bourgoyne, McGaugh, & Smith, 2007)

IPG deploys techniques from the volumetric method of well control to estimate changes in choke pressure versus pit gain while BHP is held constant. In the volumetric method, casing pressure is allowed to increase by a pre-determined amount. Next, a volume of drilling fluid holding an equivalent hydrostatic pressure to the permitted casing pressure change is bled from the well while casing pressure is held constant. By repeating this process, bottom-hole pressure can be kept relatively constant until the influx has migrated to the top of the well. The estimated volume of drilling fluid required to compensate for a change in choke pressure is dependent upon wellbore geometry, inclination angle, and mud density. (Matthews & Bourgoyne, 1983)

Barbato predicted how surface indicators, specifically choke pressure, pump pressure and pit gain would behave during a complication-free, constant pump pressure, kick circulation by using the relationship described in the volumetric method by Matthews and Bourgoyne. Barbato next compared his prediction with the behavior of surface indicators in the event of a nozzle washout to determine if the onset of a nozzle washout may be indicated by a deviation from the predicted case.

One would normally expect pump pressure to drop due to a nozzle washout without any external interference. However, if one reduced choke opening in order to maintain the target pump pressure, the end result will be a higher than expected choke pressure coupled with a lower than expected pit gain, due to the higher than expected BHP. Figure 1 details the change in observed pit gain throughout a nozzle washout simulation versus an implied pit gain prediction for a complication-free case. Please note that the observed pit gain trends lower than the implied gain for the nozzle washout simulation at roughly 75 minutes. This deviation between the observed pit gain and the implied pit gain lines represents the onset of the nozzle washout.

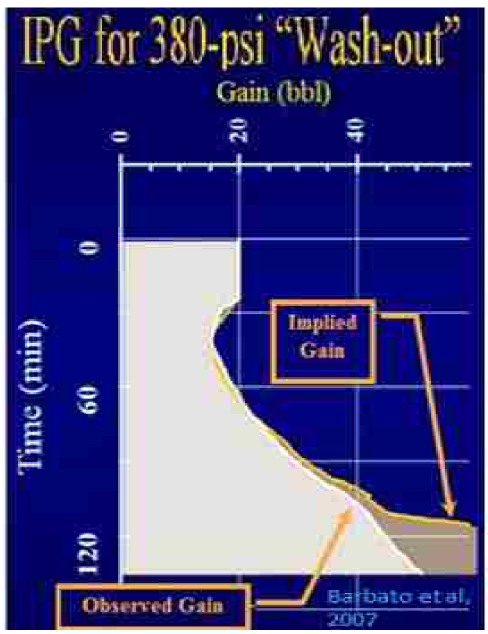

Figure 1: The deviation between observed gain and implied gain due to a nozzle washout

3.2 Traditional Well Control Diagnosis (Rehm et al, 1975)

Rehm developed a comprehensive diagnostic approach which relies primarily on correlating the behavior of surface pressures to diagnose complications. Pit gain, pump rate, and choke size are used as secondary indicators on an as needed basis. Rehm's method assumes that an operator takes a routine response to a change in surface pressures and then considers whether the resulting behaviors imply the existence of a complication. Assuming the onset of a complication is identified, the drilling crew can consult a troubleshooting matrix that guides an operator through a series of actions and observations aimed at isolating the root cause of the complication. Potential solutions to cure the complication are also given. The proposed IPG method will build off of Rehm's sound principles to provide additional value.

Table 1 offers an example of Rehm's troubleshooting process for lost circulation. The down arrows for drill pipe pressure and casing pressure represent unexpected behaviors of surface indicators. Following the recognition of the unexpected behavior, an operator is requested to take the action of decreasing choke size. Following this action, the operator will proceed through a series of if-statements in the scenario to identify which if-statement is true. If surface pressures increase after a reduction in choke size, then the operator would be led to believe that the choke size was too small. Otherwise, if pump pressure and casing pressure remained constant after choke size was decreased, the operator would be led to believe that the cause of the complication was either lost circulation, bad cement, or a hole in the casing. The operator is also asked to check pit level to confirm the diagnosis. Solutions are also offered to cure the diagnosed problem.

Table 1: Traditional diagnostic approach to diagnosing lost circulation provided by Rehm

Drill Pipe Pressure	Casing Pressure	Actions	IF (DP & CP)	Then (Result)	Solution
Down	Down	Decrease Choke Size	Up	Choke Size too large	If pressures not up, then continue to next row
			No Change	Lost Circulation, Bad Cement, Hole in Casing	Slow GPM, Barite Plug, LCM

The diagnosis of lost circulation in this example utilizes the drop in drill pipe pressure and casing pressure as leading indicators for lost circulation. Rehm expects pump pressure to fall during lost circulation because once the formation is fractured, additional choke pressure cannot be applied to offset the loss in hydrostatic pressure below the weak zone due to gas expansion. Rehm expects that choke pressure will fall in this example due to lost returns causing a reduced flow rate to the choke at a given point in time. A potential conflict with this symptom is that choke pressure can increase during lost circulation to offset the loss in hydrostatic pressure due to gas expansion and migration in the annulus when present above the weak zone.

3.3 Traditional Well Control Diagnosis Strategy (API, 2006)

The API Recommended Well Control Practices document, API-RP59 also offers an effective qualitative diagnostic tool for well control complications. The document associates specific combinations of surface indicators, i.e. pump pressure, casing pressure, drill string weight, pit gain, and pump rate trends with specific complications. Similar to Rehm's method, API-RP59 requires that an operator suspects a potential complication and observes surface indicator behaviors. Once the behavior of surface indicators has been assessed, an operator forms a diagnosis by referring to the API-RP59 for the specific complication that is associated with the observed behaviors.

Table 2 indicates the trends or behaviors that API-RP59 would qualify as being representative of lost circulation. Thus, in the event of lost circulation, an operator may see the following combination of symptoms: drop in drill pipe pressure and pit level, increase in drill sting weight, slight drop in casing pressure, and a slight in increase in pump strokes per minute (SPM). The drop in drill pipe pressure and increase in SPM are attributed to the inability of the choke to offset the lost hydrostatic pressure below the weak zone from gas expansion. The drop in pit level is an indicator that drilling fluid is leaving the system as losses to a downhole formation. The increase in drill string weight refers to a potential reduction in buoyancy as hydrostatic pressure falls. Please note that the reduction in drill string weight may not be a reliable indicator unless the reduction in BHP is substantial because buoyancy forces are small relative to total string weight. Casing pressure is expected to remain relatively constant because the column of fluid above the weak zone is expected to have a fixed hydrostatic pressure. A potential conflict with this symptom is that choke pressure can increase during lost circulation to offset the loss in hydrostatic pressure due to gas expansion and migration in the annulus when present above the weak zone.

Table 2: Traditional diagnostic approach for lost circulation provided by API

Drill Pipe Pressure	Casing Pressure	Drill String Weight	Pit Level	SPM
Down Significantly	Down slightly	Up Significantly	Down Significantly	Up slightly

3.4 Real-time Well Control Advisor (Milner, 1992)

A rigorous effort was put forth to develop a quantitative diagnostic tool for well control known as Wellsite Advisor by Tracor Applied Sciences. The objective was to design software that was capable of delivering automated problem alert, diagnosis and advice to a drilling crew on complications. In order to do so, the software intended to predict drill pipe pressure, choke pressure, pit gain, and drill string weight over the duration of a kick circulation. The predictions were performed by incorporating estimates of influx depth, density, and length as well as migration velocity. Both the predictions and estimates were supposed to be derived from proprietary algorithms acting on user inputs made at the onset of a kick circulation.

The system was intended to diagnose and provide advice on remediating well control complications based on deviations between predicted and actual behavior of surface indicators over time. Although created to be a commercial product, the system was not a commercial success and is evidently no longer being marketed. Furthermore, the knowledge embodied in this proprietary system is not available for use or further development by the public.

Development of this system was conducted as a joint industry project, which demonstrated industry interest and support for this kind of capability. In addition, Milner quotes that “industry experts did not always agree on how to interpret the results of deviations.” As a result, research in this area seems to be relevant.

3.5 Problem Detection during MPD (Saeed, Lovorn, & Davis, 2012)

Halliburton Energy Services presented a paper to the Society of Petroleum Engineers in 2012 proposing a system aimed at diagnosing complications during MPD. This effort demonstrated continued industry interest in diagnostic software. Halliburton discussed how the symptoms of complications may appear different than traditionally expected when considering the behaviors of automated choke systems. The paper goes on to mention that the diagnostic strategy assumes that the resulting behavior of surface indicators following onset of a complication will hold unique attributes or a ‘signature.’ After developing a database of ‘signatures’ over time, the software is intended to diagnosis complications in a robust fashion. Halliburton also suggests that traditional diagnostic methods that analyzed surface indicators with binary logic and without interference from proprietary choke response algorithms may need to be supplemented with additional logic going forward.

An example was presented on how automated systems can change the ‘signature’ of behaviors associated with a given event from conventional drilling operations. For example, just prior to a pack-off, the MPD choke size is increased in order to reduce choke pressure and maintain a downhole PWD sensor at a target value. As a result, a symptom of a pack-off may include a sudden opening in choke size as opposed to a growing change in pressure sensed by a PWD.

3.6 Rapid Choke Pressure Increase Response (Davoudi, 2009)

Davoudi demonstrated that the rapid choke pressure increase method of applying back pressure to stop an influx has an optimized balance between speed and minimizing total casing pressure. The rapid choke pressure increase response involves making a large choke size adjustment to reduce flow out to roughly 110% of flow in followed by smaller rapid choke size adjustments until flow rates are equal. The initial well control response used this research will follow a similar philosophy.

Davoudi also noticed that deciphering precisely when an influx has stopped is more complex for a gas as opposed to a liquid influx. The challenge arises from the fact that gas compressibility can allow flow rate out to drop below flow rate in for a brief moment in time following a choke size reduction regardless of whether or not the well is overbalanced. Given this circumstance, a rig personnel may have difficulty in addressing whether or not an influx has stopped or has been momentarily compressed.

Davoudi deploys the bumping the choke method to confirm whether or not the influx has stopped to address this issue of confirmation. Bumping the choke requires an operator to make a minor choke size reduction to observe the behavior of flow out after dropping below flow in. In doing so, Davoudi describes how rates dominated by gas compressibility, wellbore underbalance and mud pump injection will increase in a rapid fashion following the small choke size adjustment. In contrast, flow rates dominated by gas compressibility and mud pump injection alone will grow at a much slower pace over time. As a result of this, Davoudi seeks out the latter behavior to confirm an influx has stopped. Bumping the choke will be used as part of the initial well control response in this research as well.

3.7 Gas Slip Impacts the Mixture Zone Location (Chirinos, 2010)

Chirinos assumed that gas fraction within the annulus has a triangular distribution. This profile may be attributed to experimental data which suggests that gas slip velocity is greatest at the top of an influx and almost zero at the bottom of an influx. Chirinos' modeling of gas slip velocity pertains to IPG because it addresses the fact that gas slip velocity can play a role in estimating the location of the top and bottom of the mixture volume within the wellbore and the gas distribution within in the mixture volume. Being able to do so facilitates IPG base case predictions because the amount of hydrostatic pressure lost for a given change in pit gain is dependent on gas distribution and the location of the mixture volume with regard to changing inclination angles and geometries within the wellbore. Section 5 and 6 will describe the development of an IPG base case prediction in greater detail.

3.8 Simultaneous Downhole Loss and Influx (Das, 2007)

Das proposed a scenario where forcing flow rates equal to one another did not successfully stop an influx. The event involves a situation where the pore pressure gradient in the influx zone was greater than the fracture pressure gradient in the weak zone. As a result, wellbore pressure could not be increased high enough to stop an influx due to the limitations of the weak zone. Such a scenario may serve as simplification for an event where kick tolerance has been exceeded and the influx can no longer be safely circulated with the CBHP method.

Das simulated a rapid choke pressure increase response to an influx where flow rate out was held equal to flow rate in for an extended period of time. While equal flow rates normally confirm that an influx has stopped, in this event, equilibrium between lost circulation and the increased influx volume displacing drilling fluid out of the wellbore had occurred instead. As a result, forcing flow rates equal to one another masked a simultaneous downhole loss and influx event in which the well was losing circulation in the weak zone while taking additional influx at the same time.

Das' simulation suggests that further research is needed to develop a diagnostic method to confirm whether or not an influx has been successfully stopped when deploying the rapid choke pressure increase method of well control.

4 Practical Implementation of Implied Pit Gain Method

A plot predicting Δ choke pressure – Δ pump pressure vs. Δ pit gain should be developed for a complication-free case known as the IPG base case at the onset of an actual CBHP kick circulation. Data that describes the actual wellbore conditions and the initial well control response will be used to develop an IPG base case plot in an Excel™ spreadsheet. This action can be performed quickly with a pre-constructed Excel™ model. An example of an IPG base case plot for Well X, the wellbore analyzed in this research is shown directly below.

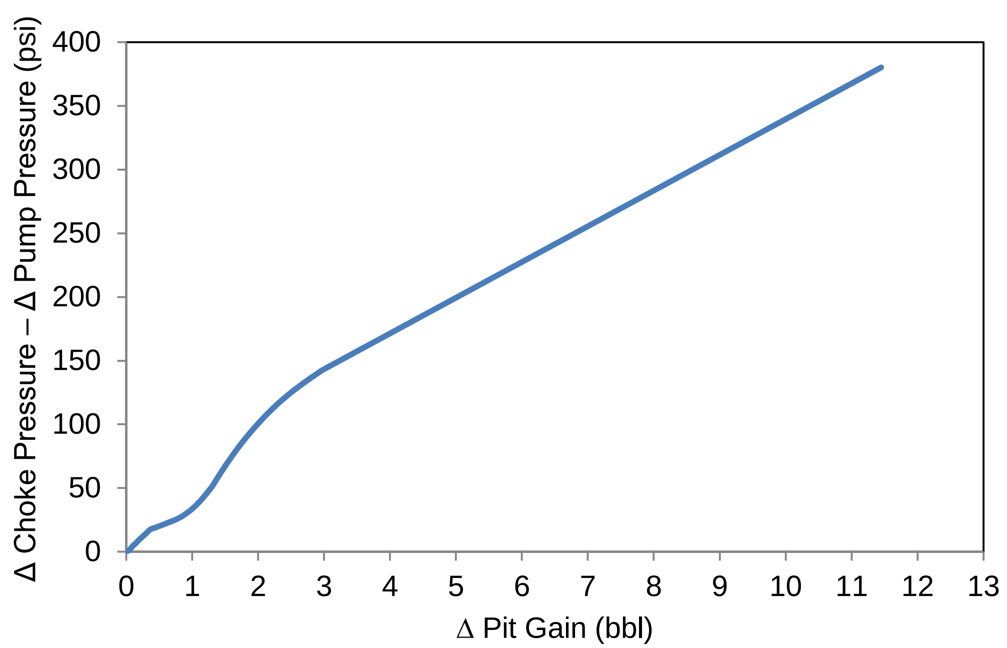

Figure 2: IPG base case prediction: deviations from this line may indicate a complication

Next, the change in pump pressure, choke pressure, and pit gain should be tracked periodically throughout a constant pump pressure kick circulation. In this research, Drillbench Kick is assumed to be a proxy for field conditions. Thus, the process of recording actual field data will be performed by exporting SPT Drillbench Kick simulation raw data to a spreadsheet. Upon doing so, the Δ choke pressure – Δ pump pressure vs. Δ pit gain for the simulated-actual circulation data would be transferred into a plot known as an IPG simulated-actual plot or simply an IPG actual plot.

The final stage of the implementation involves a comparison of the IPG actual plot over time with the IPG base case plot. In the event of a complication-free kick circulation, the IPG actual and base case plots should have similar profiles throughout the entire kick circulation. Alternatively, if a complication occurs, a deviation of the IPG actual plot from the IPG base case plot is expected. When reviewing this deviation, a rig personnel or an automated system is expected to search for a unique combination of attributes that could potentially associate the unique characteristics of the IPG actual plot with a specific complication. Furthermore, statistical analysis may need to be deployed to determine if a deviation is significant with regard to minute deviations that could occur due to noise.

5 Derivation of IPG Relationship for Predictions

This section will derive the relationship between changes in choke pressure and changes in pit gain used to create an IPG base case prediction. Additionally, the IPG equation will be generalized to also suit the purpose of analyzing data from an actual kick circulation that may or may not have a complication. In this research, actual conditions are represented by Drillbench Kick simulation data. Furthermore, all scenarios discussed in this research are based on a gas influx in water-based mud.

5.1 Relationship Between Δ Choke Pressure and Δ Pit Gain

The IPG method is based on the necessity for choke pressure to be increased to offset the loss of hydrostatic pressure associated with drilling fluid being displaced from the wellbore due to gas expansion in order to keep BHP constant. The quantitative basis originated from the volumetric method discussed in Section 3.1.

Changes in circulating friction may also cause the need to change choke pressure to a lesser degree. For example, choke pressure may need to increase to offset a reduction in circulating friction as a result of the drop in viscosity and density of mixture column. Furthermore, choke pressure may need to be decreased as rapid gas expansion near the surface increases the rate of flow through a given choke opening which can drive BHP upward. A sensitivity analysis that determines the significance of changes in circulating friction is not included in this research. Further work discussed in this research demonstrates that excluding the impacts of circulating friction allows one to develop a base case prediction that is robust enough to address the objectives of this research.

Equation 3 expresses Δ BHP as the sum of Δ choke pressure, Δ annulus circulating friction, Δ drilling fluid hydrostatic pressure, and Δ influx hydrostatic pressure.

Equation 3: $\Delta \mathrm{BHP} = \Delta \mathrm{P}_{\mathrm{choke}} + \Delta \mathrm{P}_{\mathrm{friction,ann.}} + \Delta \mathrm{P}_{\mathrm{hydrostatic,drilling\ fluid}} + \Delta \mathrm{P}_{\mathrm{hydrostatic,influx}}$

An IPG base case prediction assumes that BHP, influx hydrostatic pressure, and annular circulating friction are relatively constant throughout a CBHP kick circulation as shown in Equation 4. As a result, choke pressure must increase to offset the loss in hydrostatic pressure associated with gas expansion pushing drilling fluid out of the wellbore to maintain a CBHP as shown in Equation 5 and Equation 6. Please note that annulus capacity factor is in the units of bbl/ft, CosΘ is used to obtain the vertical height of a fluid column in a deviated section and ρ_m is the drilling fluid density in ppg.

Equation 4: $0 = \Delta P_{\text{choke}} + 0 + \Delta P_{\text{hydrostatic,drillingfluid}} + 0$

Equation 5: $\Delta P_{\text{choke}} = -\Delta P_{\text{hydrostatic,drilling fluid}}$

Equation 6: $\Delta P_{\text{choke}} = .052 * \rho_m * \left(\frac{-\Delta V_{\text{drilling fluid}}}{\text{Annulus Capacity Factor}} \text{Cos}\Theta\right)$

Since gas expansion is displacing drilling mud from the wellbore, the change in mud volume ($-\Delta V_{\text{drilling fluid}}$) is equivalent to the change in pit gain (ΔV_k). As a result, Equation 6 can be rewritten to demonstrate the dependence of hydrostatic pressure on ΔV_k as shown in Equation 7. In this form of the equation, the fundamental relationship between Δ choke pressure and Δ pit gain in the IPG base case prediction is derived. (Matthews & Bourgoyne, 1983)

Equation 7: $\Delta P_{\text{choke}} = .052 * \rho_m \frac{\Delta V_k}{\text{Annulus Capacity Factor}} \text{Cos}\Theta$

A basic application of the above concept was demonstrated with an SPT Drillbench Kick simulation in a single geometry, vertical wellbore shown in Figure 3. In this research, Drillbench is used to simulate actual conditions. The Drillbench simulation depicted a 5.8bbl pit gain expanding to a 14.1 bbl pit gain during a CBHP kick circulation. This change in pit gain required choke pressure to increase from an initial choke pressure of 1195 psi to a final choke pressure when gas reached the surface of 1442 psi to maintain CBHP. The drilling fluid had a density of 13.2ppg and the annulus capacity factor was .02307bbl/ft. By plugging the simulation results into Equation 7**,** one can see that the Δ choke pressure is a predictable function of Δ pit gain.

$$\Delta \mathrm{P_{choke}} = (1442\mathrm{psi} - 1195\mathrm{psi}) = .052 * 13.2\mathrm{ppg} * \frac{(14.1\mathrm{bbl} - 5.8\mathrm{bbl})}{.02307\ \mathrm{bbl/ft}} \mathrm{Cos}(0)$$

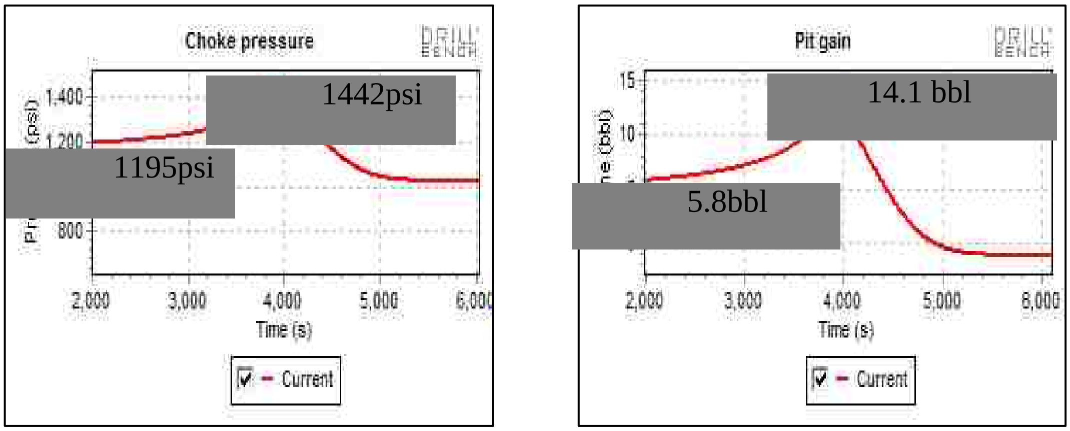

Figure 3: Δ choke pressure and Δ pit gain for a vertical wellbore

5.2 Calculating an IPG Base Case Prediction

The prediction of an IPG base case involves quantifying the relationship between changes in choke pressure and changes in pit gain during a CBHP influx circulation. This section will start with the most basic IPG base case prediction in a fixed geometry and single inclination angle wellbore section. Next, the procedure used to calculate an IPG base case in a wellbore with varying geometry and inclination angle sections will be discussed.

5.2.1 Wellbores with a Single Geometry and Inclination Angle

The calculation of the IPG base case begins with a rearrangement of variables in Equation 7 intended to demonstrate that Δ choke pressure and Δ pit gain are related by a slope that is dependent on mud density, inclination angle and annulus capacity factor. This relationship is described in a simplified form in Equation 8 which holds true in a wellbore that has a single geometry and fixed inclination angle. The most common example is a vertical wellbore.

Equation 8: $\Delta P_{choke} = V_k * \frac{.052 * \rho_m * \text{Cos}\ \Theta}{\text{Annulus Capacity Factor}}$

The inclusion of Cos Θ in Equation 8 is required to account for fact that the hydrostatic pressure lost for a given change in pit gain is decreased as wellbore inclination angle increases. This is due to the fact that the hydrostatic pressure of a volume of fluid is dependent on its vertical length. Thus, an influx volume in a deviated section has a lower vertical length than the same volume of influx in a vertical section.

Assuming the entire wellbore consisted of a single geometry and fixed inclination angle, the IPG base case plot would appear as a straight line. Since IPG predictions are driven by changes in choke pressure and pit gain, the IPG base case plot originates at point 0,0. An example of the most basic IPG base case curve is shown in Figure **4** for a complication-free kick circulation in a vertical wellbore.

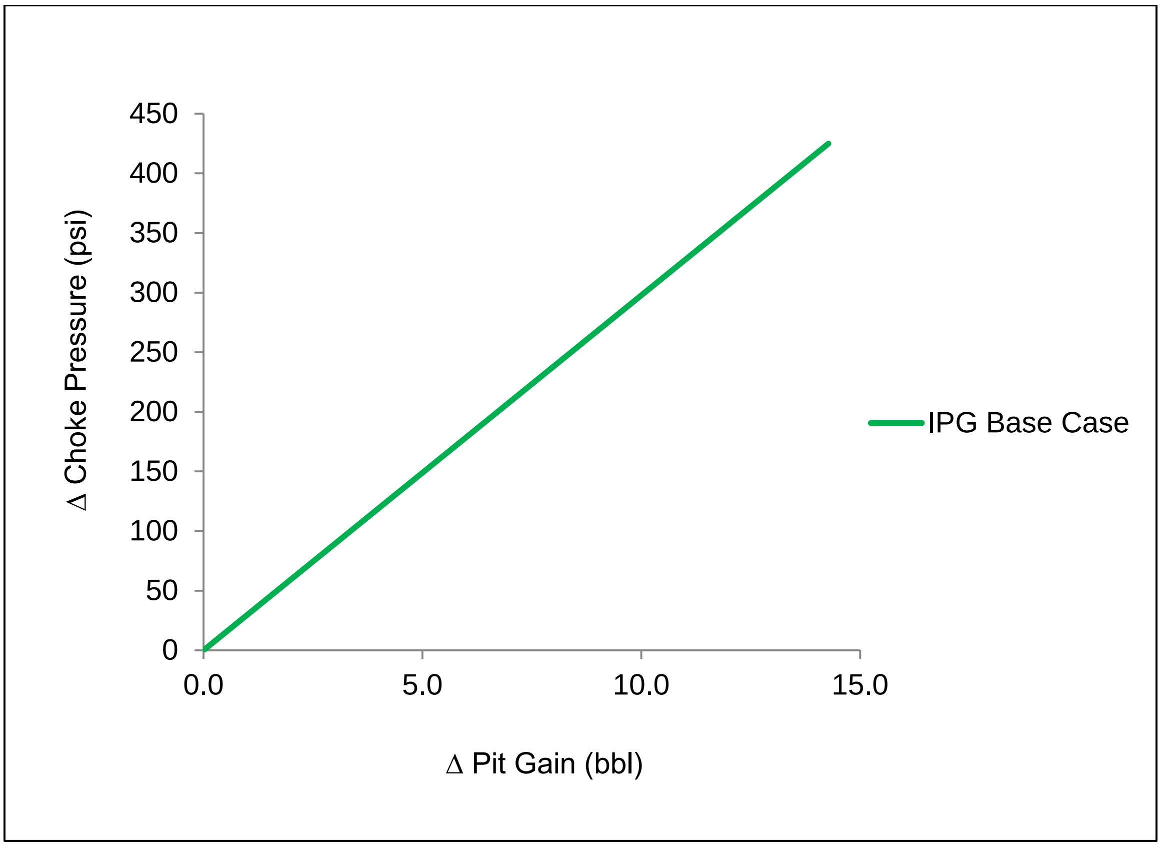

Figure 4: IPG base case in Excel™ for a vertical wellbore

5.2.2 Wells with Changing Geometry and Inclination Angle

Most industry well designs have changing geometries and inclination angles. The changing geometries are caused by differing BHA and drill pipe OD's as well as varying open hole, liner and casing diameters. Changing inclination angles can be caused by planned or accidental wellbore deviations in order to achieve a target depth.

The relevance of changing geometry and inclination angles is such that an influx may span multiple regions each containing a different capacity factor and Cos Θ values. Since these two variables contribute to the vertical dimension of the drilling fluid volume displaced, estimating the amount of influx in each section of the wellbore is critical to calculating the hydrostatic pressure lost for a given change in pit gain.

As a result, one must deploy Equation 9 to the estimate the change in influx volume occurring in each interval at a given moment in time in order to predict the change in choke pressure for an IPG base case.

Equation 9: $\Delta P_{choke} = \sum(\Delta V_k * \frac{.052 * \rho_m * Cos\Theta}{CapFactor})_{interval}$

For example, assume a 10 bbl influx has 2 bbls positioned in a vertical section with a capcity factor of .02306 bbl/ft and 8 bbl in a deviated section with a capacity factor of .02106 bbl/ft with an inclination angle of 15 degrees. The drilling fluid is a 13.2ppg mud. The initial pit gain occurred in the deviated section at a value of 7bbl. $\Delta P_{hydrostatic, vertical}$, $\Delta P_{hydrostatic, deviated}$, $\Delta P_{hydrostatic, total}$ refer to the lost hydrostatic pressure in the vertical and deviated sections as well as the whole wellbore respectively. In such circumstances, the following calculations would be performed to obtain the total choke pressure required to offset the loss in wellbore hydrostatic pressure:

$$\Delta P_{hydrostatic,\ vertical} = 60psi = (2-0) * \frac{.052 * 13.2 * Cos\ (0)}{.02306}$$

$$\Delta P_{hydrostatic,\ deviated} = 252psi = (8-7) * \frac{.052 * 13.2 * Cos\ (15)}{.02106}$$

$$\Delta P_{choke} = \Delta P_{hydrostatic,total} = 60 \text{ psi} + 32 \text{ psi} = 92 \text{ psi}$$

As a result, the IPG base case prediction of the ΔP_{choke} associated with a ΔV_k of 3bbl is equal to 92 psi in the context of the example scenario. If the ΔP_{choke} tracked during an actual kick circulation was significantly different from 92 psi at 3bbl of Δ pit gain, one might assume that a complication is occurring.

An example of an IPG base case that undergoes a geometry change from a 6" annulus to an 8" annulus is shown in Figure 5 for a complication-free case. Under such circumstances the IPG base case line is no longer a basic straight line. Instead, the slope of the IPG base case becomes negative to account for the increase in hydrostatic pressure associated with a gas influx moving into a wider annulus and assuming a wider cross sectional area and reduced vertical height. The chart also shows that once that majority of influx is in the wider annulus, vertical gas expansion becomes the driving factor of hydrostatic pressure changes once again and choke pressure continues to rise with increasing pit gain.

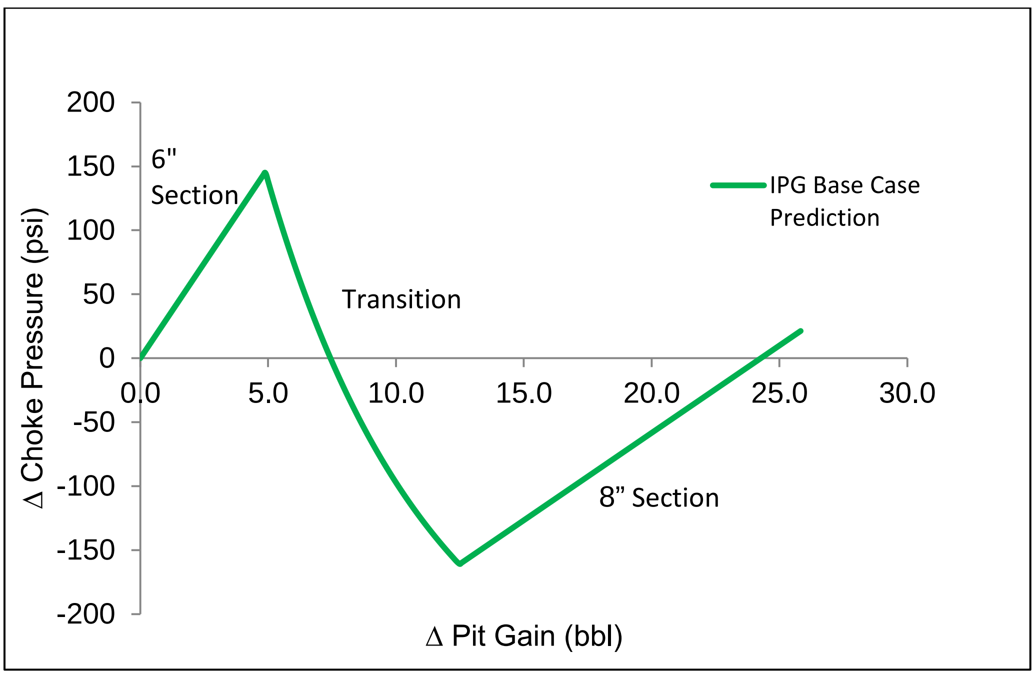

Figure 5: IPG base for a wellbore with a geometry change

An example of an IPG base case in a wellbore with a change in inclination angle is shown in Figure 6. In this theoretical case, a 45 degree wellbore section adjoins abruptly to a vertical wellbore section. Please note that as the mixture volume transitions into the vertical section, casing pressure grows rapidly to accommodate the increased loss in hydrostatic pressure as the mixture volume is oriented into a vertical position. Thus, the same size influx volume in the vertical section has a greater impact on lost hydrostatic pressure then when positioned in the 45 degree section. Furthermore, once the influx is positioned entirely in the vertical section, the IPG base case slope tapers reflecting the fact that the increase in choke pressure is now dominated by gas expansion alone, not a change in inclination angle.

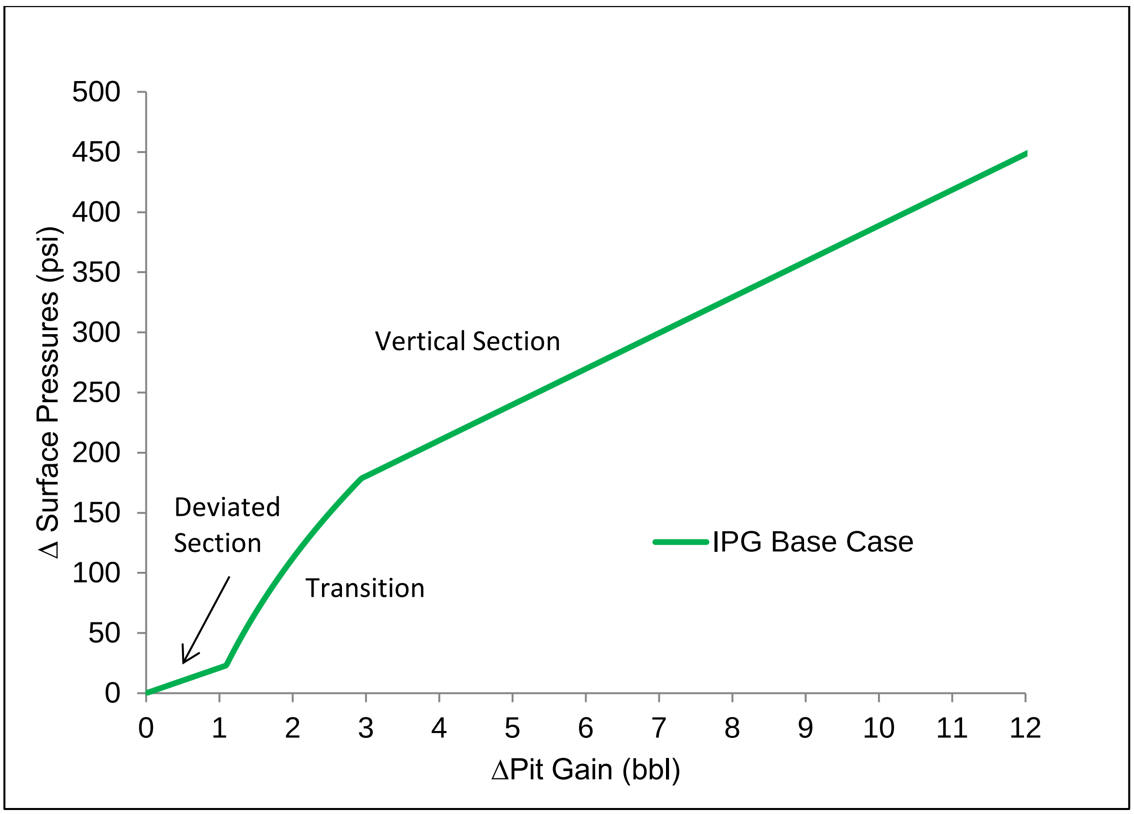

Figure 6: IPG base case for 45 degree section adjoining to vertical section

5.3 Application of the IPG Relationship to Kick Circulation

Equation 9 can be generalized further to represent the relationship between surface pressures and pit gain in both a theoretical IPG base case prediction and when analyzing field-based kick circulation data by subtracting the change in pump pressure from the left hand side. The generalized version of the IPG relationship is shown below in Equation 10. The ΔP_{pump} term refers to changes in drill pipe pressure. Additionally, $\Delta P_{choke} - \Delta P_{pump}$ may also be referred to as Δ surface pressures. (Barbato, Bourgoyne, McGaugh, & Smith, 2007)

Equation 10: $\Delta \mathrm{P}_{\mathrm{choke}} - \Delta \mathrm{P}_{\mathrm{pump}} = \sum(\Delta \mathrm{V}_{\mathrm{k}} * \frac{.052 * \rho_{\mathrm{m}} * \mathrm{Cos}\Theta}{\text{Annulus Capacity Factor}})_{\mathrm{interval}}$

The ΔP_{pump} included in Equation 10 serves multiple functions. First, the ΔP_{pump} term can be used to account for reasonable variations in BHP that can occur during complication-free kick circulations in the field. For example, if 25psi of choke pressure is added when only 20 psi of hydrostatic was lost, BHP will be increased by 5 psi. The ΔP_{pump} term also increases by 5psi to account for this small variation. The resulting change in Δ pit gain due to system compressibility is assumed to be negligible. In a kick circulation with complications, the ΔP_{pump} term also serves to create unique attributes in the IPG actual curve that can be utilized to diagnose the cause of a problem. Such attributes may be observed in the Well X complication simulations in Sections 10, 11, and 12. The data from these simulations will be treated as a proxy for actual field conditions. Going forward, the ΔP_{pump} term will be included in the IPG formula. However, when calculating the IPG base case, one must assume that $\Delta P_{pump} = 0$.

6 IPG Base Case Depends on Gas Location (Slip vs No-Slip)

As explained in the section on changing geometry and inclination angles, the loss in wellbore hydrostatic pressure due to influx expansion is dependent on the location and volume of the influx throughout the wellbore at a given moment in time. In order to estimate the location of the mixture volume, the following assumptions have been made:

1. The initial mixture volume is estimated as the sum of the initial pit gain plus the amount of mud pumped during the period that the wellbore was underbalanced under no-slip conditions.
2. The bottom of the mixture column is displaced upward at the flow rate of the mud pumps.
3. The top of the mixture volume is at a height above the bottom determined by the real gas law with a no-slip assumption.
4. When assuming slip conditions, the mixture volume also increases as a function of time.
5. The void fraction in the mixture volume is uniform at all times and constant with a no-slip assumption and decreasing over time with a slip assumption. Increases in influx volume due to real gas law and movement due to gas slip velocity result in an increased mixture volume length.
6. The pressure on the mixture volume is calculated as an average of the pressure on the top and bottom of the mixture volume. This calculation implies a uniform void fraction distribution over the length of the influx.
7. Since the gas influx is assumed to be evenly distributed throughout the mixture volume, the prediction of the mixture volume in each section of the wellbore can be used to predict the volume of influx in each wellbore section also.
8. The wellbore has taken a gas influx in water based mud.

6.1 Location with a No-Slip Assumption

The location of the mixture volume is dependent on an estimate of the location of the top and bottom of the mixture volume. The bottom of the mixture volume travels at the pump rate. The top of the mixture volume is dependent on the total mixture volume which continuously expands with real gas law during a CBHP circulation.

6.1.1 Estimating Total Initial Mixture Volume (No-Slip)

Equation 11 explains that the initial mixture volume can be estimated as the sum of the initial pit gain plus the amount of mud pumped during the period that the wellbore was underbalanced. This estimate assumes no-slip conditions. A slip assumption will be discussed in Section 6.2.

Equation 11: $\text{Initial Mixture Volume} = \text{Initial Pit Gain} + \text{Pump Rate} * \text{Time}$

6.1.2 Bottom of the Mixture (No-Slip)

The bottom of the mixture volume is assumed to be displaced upward at the same rate that the mud pumps are injecting drilling fluid into the wellbore. The initial location of the bottom of the mixture volume when CBHP has started is based on the amount of mud pumped between when the influx was confirmed to be stopped and when a CBHP circulation has started. In this work, a CBHP circulation is initiated when a constant pump pressure is attained and pit gain is no longer decreasing due to gas compression from the rapid choke size reductions used to stop the influx. When the influx is stopped, the base of the influx is assumed to be level with the base of the high pressure zone. Next, the base of the influx is assumed to be displaced by the amount of barrels pumped until a CBHP is initiated. The bottom continues to be displaced upward throughout the CBHP circulation at the flow rate of the mud pumps.

6.1.3 Top of the Mixture (No-Slip)

The top of the mixture volume is at a height above the bottom determined by gas expansion with the real gas law assuming a uniform and constant void fraction. The pressure on the mixture volume is assumed to be equivalent to the average of the pressure on the top and bottom of the mixture volume. An iterative solution is used to estimate the change in the pit gain as the base of the mixture volume is displaced upward. In the case of IPG base case predictions, if the influx volume increases by a certain percentage then the mixtures volume is increased by the same percentage, thereby driving the top of the mixture volume upward. These calculations allow the gas influx to increase in volume and reduce in density in order to preserve mass and imply a constant gas fraction in the mixture.

An expansion of the influx volume with real gas law is calculated by estimating the pressure change on the mixture volume over a given increment in time. Thus, over a given time-step, the upward circulation of the mixture volume results in a decrease in the amount of hydrostatic pressure and circulating friction that are exerting downward pressure on the influx. The change in the amount of hydrostatic pressure and circulating friction above the mixture volume for each time-step is used to calculate expansion with the real gas law. Allowing gas to expand in this fashion during a kick circulation permits a CBHP circulation.

Since, the top of the mixture volume is needed to calculate average pressure and average pressure is needed to calculate the top of the mixture volume, an iterative solution is used to estimate the change in the pit gain as the base of the mixture volume is displaced upward.

6.2 Location with a Slip Assumption

A more precise IPG base case prediction may be developed by taking into account how the location of the top of the mixture volume may change with time and due to gas slip velocity and real gas law expansion. Research done thus far by Chirinos and simulations executed with SPT Drillbench kick, suggest that gas slip velocity may cause a mixture volume to reach a transition zone at a lower Δ pit gain than predicted in a no slip IPG base case. This behavior may be attributed to the fact that under slip conditions, the resulting mixture volume may have a longer length, lower gas fraction, and exist under a higher overall pressure in comparison to the mixture volume in a no-slip model with an influx top at the same wellbore depth. Thus, gas slip velocity modeling can enhance one's ability to more correctly estimate the ∆ pit gain in which a mixture volume reaches a geometry/inclination angle change. In doing so, one can ultimately develop a more robust prediction of the relationship of ∆ surface pressures versus pit gain during a kick circulation.

6.2.1 Gas Slip Velocity Correlation

According the full-scale experiments performed at Louisiana State University (LSU), gas is expected to slip past a heavier density drilling fluid during a kick circulation thereby causing the top of the mixture volume to move at a faster rate than predicted in a no-slip model. Based on these experiments, an empirical correlation was developed to estimate gas slip velocity by taking into account the rheological properties of the drilling fluid, difference in density between the drilling fluid and influx, as well as the estimated gas fraction. The report is private and held at the Department of Petroleum Engineering at LSU. (Amoco Production Company, 1986) Since the LSU experiments were performed in a vertical well, the correlation was multiplied by the Cosine of the inclination angle as an assumption to approximate gas slip velocity in deviated sections. The resulting correlation is shown in Equation 12.

$$\text{Equation 12: } V_S = \left(\frac{\tau}{\mu}\right)^{.12}\left(\frac{\rho_m - \rho_g}{\rho_m}\right)^{.25}(4.92\lambda + 1.25) * \mathrm{Cos}\Theta$$

V_s = gas slip velocity (ft/s)
τ = yield point
μ = plastic viscosity
ρ_m = mud density
ρ_g = influx density
λ = void fraction

6.2.2 Estimating Total Initial Mixture Volume (Slip)

Equation 11 explains that the initial mixture volume can be estimated as the sum of the initial pit gain plus the amount of mud pumped during the period that the wellbore was underbalanced. Equation 13 expands on that calculation to include the impacts of gas slip velocity during the same period.

Equation 13: Initial Mixture Volume = Initial Pit Gain + Pump Rate * Time + V_s*Time*Capacity Factor

6.2.3 Bottom of the Mixture (Slip)

The bottom of the mixture volume is displaced according to the same assumptions and strategies described Section 6.1.3 for the no-slip model. In short, the base of the influx is displaced upward at the flow rate of the mud pump(s).

6.2.4 Top of the Mixture (Slip)

The top of the mixture volume is at a height above the bottom determined by the real gas law and a uniform and decreasing void fraction distribution over time attributed to gas slip velocity. The uniform distribution is a simplification from the triangular distribution that Chirinos assumed.

The mixture volume length is increased at each time step to account for pressure changes on the influx attributed to displacement upward from the mud pumps as well as the distance traveled by the top of the influx over a given time period due to slip. Since the pressure on the influx is measured as an average of the pressure on the top and bottom of the mixture volume, an iterative solution is required to estimate the change in mixture volume top. Changes in the depth of the mixture volume top are accounted for as soon as the influx enters the wellbore.

6.3 Spreadsheet Model for IPG Base Case Predictions

An Excel™ spreadsheet model has been developed to predict the change in choke pressure versus change in pit gain for a CBHP, complication-free kick circulation.

There are existing proprietary simulation models available in industry that can also be utilized to obtain a similar prediction. However, the Excel™ model offers the advantage of being able to be modified to account for various assumptions on gas slip velocity and void fraction that are available in the public domain. The Excel™ model also deploys automation to predict an IPG base case when the rapid choke pressure increase response is only 3.5 minutes. Existing industry simulators may only have an automated kick circulation feature for traditional well control responses. However, predicting a base case when deploying the rapid choke pressure increase method may require significantly more time and manual effort. Modeling the correct initial well control response is valuable because the initial mixture volume, void fraction, pit gain and location in the wellbore upon starting a constant pump pressure circulation impact the shape of the IPG base case prediction.

Modeling the estimation of the location of the mixture volume and subsequent impact on lost hydrostatic pressure can become complex and time consuming for an entire kick circulation because an actual wellbore contains multiple segments of varied inclination angles and geometries. Making an IPG base case prediction is time consuming and impractical unless the method is supported with automation. As a result, an Excel™ Spreadsheet model has been built to predict the location of the mixture volume after each pump stroke as well as to create an IPG base case prediction plot. The iterative solution referenced in section 6.2.4 is performed with the Solver function in Excel™ and automated with VBA for each time-step. The length of a time-step can be varied. However, for this research, the time step has been set to the time needed to pump 1 bbl of drilling fluid, 13.26 seconds. The Excel™ model has slip and no-slip IPG base case predictions.

Please note the following assumptions and limitations of the Excel™ model. First, the existing model assumes that the influx can only be present in two different geometry sections at one time and up to three different geometries can programmed into the tool for an entire wellbore. The model also assumes that the drill string and high pressure zone is on bottom. The pump rate does not change following the moment that the influx has entered the wellbore. The model also assumes a gas influx in water based mud. Finally, a constant pump pressure and therefore, a CBHP, complication-free, kick circulation is assumed.

6.3.1 Model Pre-Kick Inputs

The Excel™ model may be populated with several inputs that pertain to the overall wellbore scenario prior to taking a kick.

1. Drill pipe and BHA OD & Length
2. Casing ID &setting depth, and drill bit diameter
3. Survey for measured depth, vertical depth, and inclination angle at each recorded depth

6.3.2 Model Post-Kick Inputs

After taking an influx, the spreadsheet requires the following inputs in order to obtain the IPG base case Prediction.

1. Pump rate (same as drilling)
2. Mud density and rheology
3. Amount of time the well was taking an influx.
4. Initial pit gain
5. Estimate of annulus circulating friction
6. BHP after stopping influx
7. Amount of time between the start of influx and CBHP circulation commencing
8. Depth of high pressure zone
9. Estimate of formation temperature and formation fluid specific gravity

6.3.3 IPG Base Case Predictions

The final output of the Excel™ model is shown in Figure 7 in the form of an IPG base case plot for the slip and no-slip models. The lower total ∆ pit gain associated with the slip model is attributed to a longer mixture volume with a lower average gas distribution that reaches the surface under a greater average pressure than its no-slip model counterpart. The difference in ∆ pit gain values at which trajectory changes occur are attributed to gas distribution modeling as well.

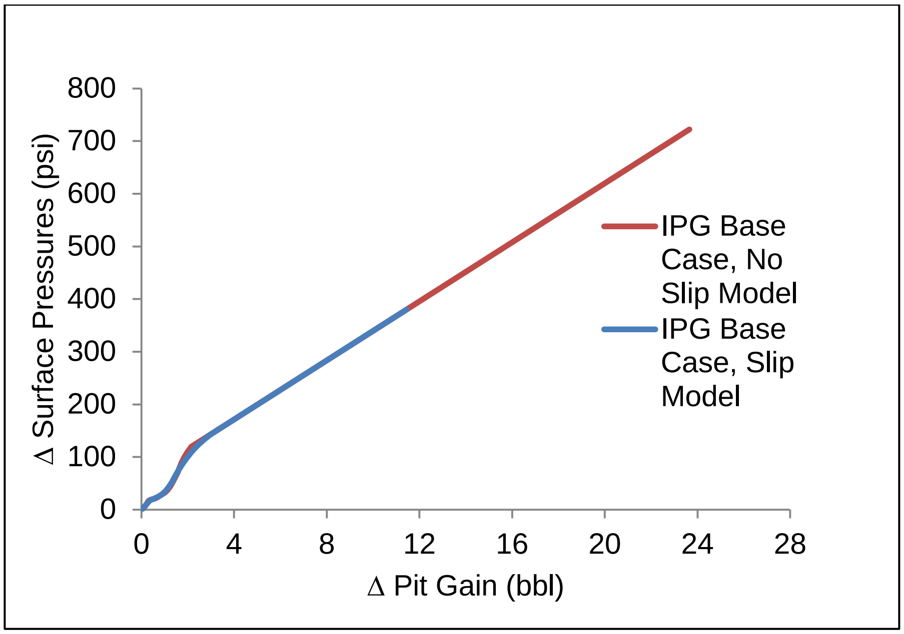

Figure 7: IPG base case with slip and no-slip modeling from the Excel™ model

7 Application to Investigate the IPG Method

A four-tiered level of assessment will be followed in order to evaluate the effectiveness of IPG. First, the ability to reasonably predict the behavior of surface indicators during a successful kick circulation will be measured by comparing IPG base case predictions with a complication-free simulation in SPT Drillbench Kick. Next, a range of complications will be simulated with SPT Drillbench Kick and compared to the IPG base case in order to determine if significant deviations from the IPG base case conclusively identify the occurrence of a complication. Third, the deviations created by the simulated complications will be analyzed for particular attributes that can help to diagnose specific complications. Finally, the potential for the IPG to provide additional value relative to traditional diagnostic methods will be explored.

7.1 SPT Drillbench Kick

The SPT Group's Drillbench Kick module was selected as the simulation software to conduct testing on the IPG method. Drillbench kick was chosen because of its ability to model taking an influx and implementing well control procedures. The software also models multiphase flow and lost circulation. The user can manually manipulate choke size and pump rate in the midst of a simulation with the Drillbench Kick. The ability to do so is critical in simulating a rapid choke pressure increase well control response as well as creating complication scenarios. Finally, Drillbench also permits the investigation of wells with changing geometries and inclination angles.

Drillbench Kick will first be used to verify that the behavior of surface indicators can be predicted with confidence during a complication-free kick circulation. To do so, IPG base case predictions will be made with the Excel™ model described in Section 6.3. Next a kick circulation will be performed with Drillbench Kick as means of simulating a complication-free, kick circulation that is assumed to serve as a proxy for field conditions. Ultimately, data from the Excel™ model will be compared to data from the Drillbench Kick simulation to determine if the IPG base case prediction method is sufficient to investigate the other objectives of this work.

Drillbench Kick will be used to simulate an array of complications that may occur at the surface and in the wellbore. One should note, Drillbench Kick is not specifically designed to simulate sudden complications in the midst of a simulation. However, the research methods involved in this work expand upon the Drillbench technology with basic assumptions to create complication scenarios. Thus, leaks and plugging in the MPD Choke, RCD, drill string, bit, and mud pump as well as operator error and exceeding kick tolerance will be modeled by varying choke size, pump injection rate, bit nozzle geometry, pore pressure and fracture pressure. The modeling procedure for all complications will be described in Sections 10, 11, and 12.

7.2 Design of Simulated Complication Scenarios

This section will summarize general design of the complication scenarios

1. Pore pressure, fracture pressure remain fixed during a complication simulation.
2. Pore pressure and fracture pressure will be modified prior to starting simulation to induce consequences that can result from the onset of complication.
3. The wellbore geometry, inclination angle, and total depth are the same for all scenarios.
4. Over/underbalance can be modified during the simulations with choke size adjustments to induce consequences as well.
5. The pump rate is fixed (190 gpm), unless a pump inefficiency is simulated.
6. The initial pit gain is the same for all scenarios (10 bbl) except when kick tolerance is exceeded requiring a larger influx volume to be taken (15 bbl).
7. There is assumed to be sufficient mud on the drilling rig to handle excessive lost returns.
8. Mud weight (13.5 ppg WBM) and rheology remain fixed for all simulations.
9. The MPD choke, RCD, or mud pumps are not limited by a maximum pressure.

8 IPG Base Case Prediction for Well X

8.1 Well X Profile

All scenarios explored in this research will be tested on Well X. The concept of Well X is derived from an actual side track well that deployed CBHP-MPD with the intention of preventing lost circulation while drilling through alternating high pressure and depleted formations. The well contains a slim-hole annulus and is drilled down to a 15515’ VD, 17625’ to simulate high pressure, high temperature conditions.

A single geometry, 11.6 degree inclination angle wellbore connects the surface to the kick-off depth of the side track well at 10,000’ MD, 9700’ VD. Traditionally, wells are not intentionally spudded with an immediate deviation at the surface. However, this theoretical wellbore design offers the advantage of demonstrating how accurately the IPG method can predict the behavior of surface indicators when the mixture column of an influx is positioned entirely within a fixed geometry section with a constant inclination angle that is greater than zero.

The casing string in Wellbore X is set at 12000’ MD, 11,280’ VD with a 6.094” ID. A 6” drill bit is used to drill the remainder of the wellbore to a 17625 MD, 15515 TVD. As a result, the behaviors demonstrated in the IPG plots will be mainly representative of changes in inclination angle. The casing was set at a shallow depth to allow ample time for complications to occur before the influx had passed fully into the casing. In doing so, the potential impacts of lost circulation involving both drilling fluid and the gas influx could be observed. However, the resulting IPG complication case curves are not sensitive enough to yield attributes which indicate if both gas and drilling fluid were being lost to the weak zone. Thus, dual phase losses will not be discussed in detail in this research.

Figure 8 depicts Well X in terms vertical depth and horizontal displacement. Well X has an 11.6° deviation from the surface to 10,000 MD, 9,700 VD. Below that depth, the wellbore builds to inclination angle that varies between 42-46° as noted in the blue section. Well X has a total depth of 17,625' MD, 15,515' VD.

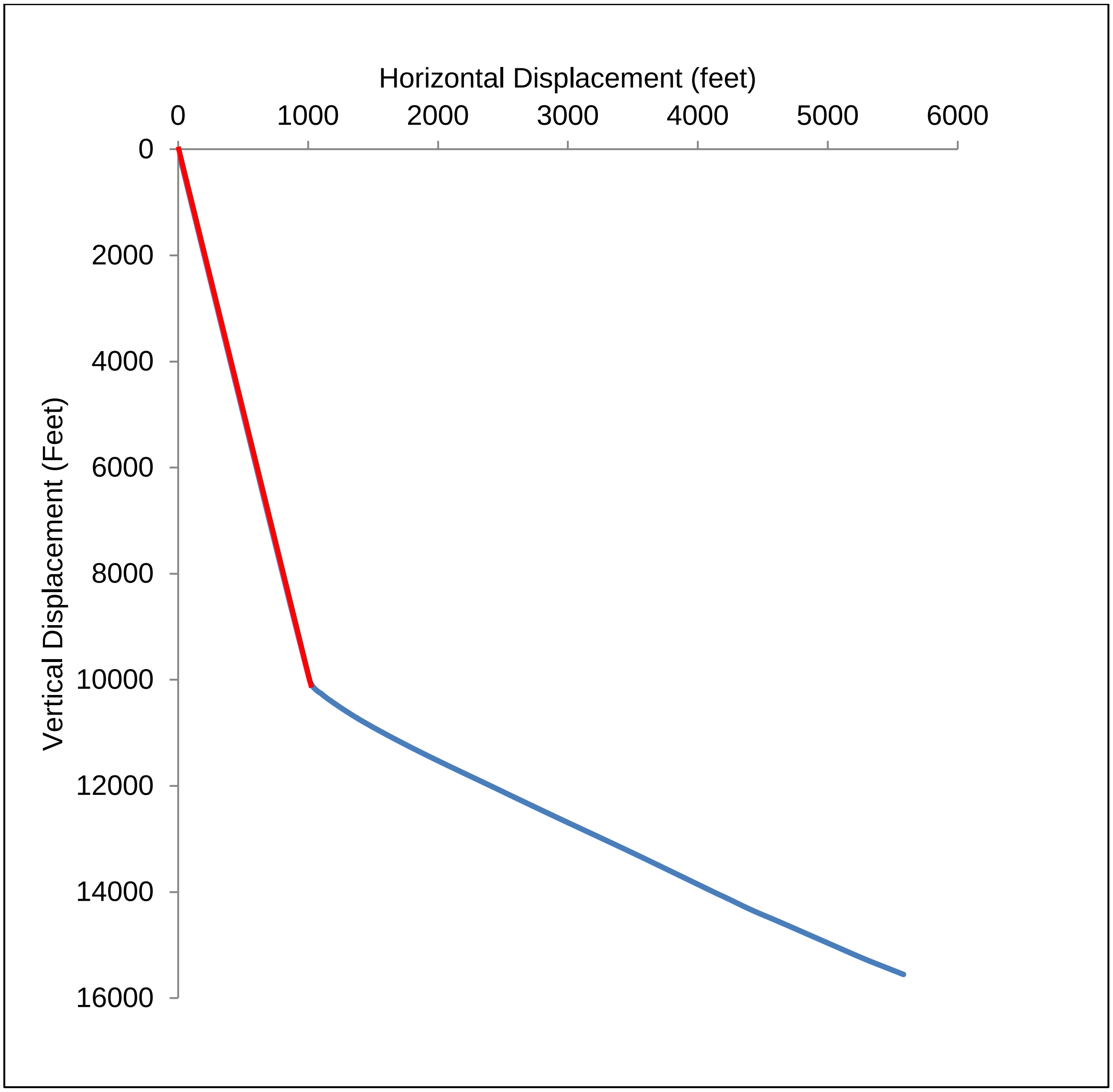

Figure 8: Vertical vs. horizontal displacement profile of Well X

8.2 Well X IPG Simulated Case with No Complications

An IPG actual case was simulated with SPT Drillbench for a scenario with no complications in Figure 9. The plot consists of ∆ Surface Pressures on the Y axis and ∆ Pit Gain on the X axis. Annotations on this plot detail the location of the mixture volume in the annulus throughout the kick circulation.

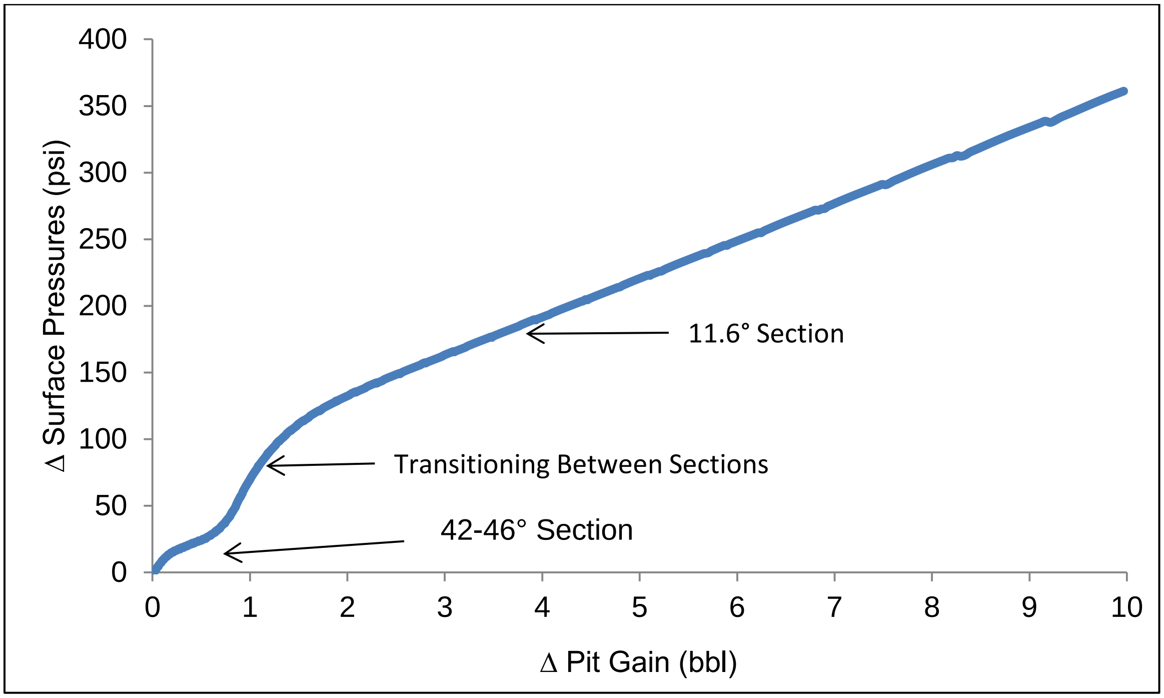

Figure 9: IPG actual curve for complication-free scenario simulated with SPT Drillbench

The relatively shallow and stable slope demonstrated at more than 2 bbl of ∆ pit gain is the result of the entire mixture volume being positioned above 10,000’ MD which has a fixed inclination angle. Thus, the loss in hydrostatic pressure is dominated by gas expansion alone. The relatively steep slope between .75 bbl and 2 bbl is representative of the mixture volume transitioning between wellbore sections that differ in terms of inclination angle such as the build from 11.6° section to 42-46° below 10,000’ MD. The slope becomes steeper in these circumstances because additional choke pressure is required to offset the loss in hydrostatic pressure associated with the orientation of the mixture volume becoming more vertical.

8.3 Well X Base Case Prediction vs. Simulation

IPG base case plots for slip and no slip conditions were built in Excel™ and compared to the IPG actual case modeled in Figure 9 for a complication-free, 10 bbl kick circulation. The comparison is shown below in Figure10. Both the IPG base case curves and IPG actual curve is reasonably similar with regard to the accuracy, sensitivity, and repeatability of rig gauges to move forward with answering the objectives of this research.

The difference between the predicted and simulated cases in terms of the timing of slope of trajectory changes as well as the maximum Δ pit gain may be attributed to differences in assumptions regarding gas void fraction distribution and gas slip velocity. The slight dip in the IPG actual case between 8-11 bbl of Δ pit gain is attributed to a manual error in choke control while performing the simulation in SPT. The SPT software does an automated kick circulation mode which can prevent these manual errors. However, the rapid choke pressure increase well control response cannot be deployed with the automated mode.

Despite these differences, once the mixture volume is entirely in a section with a fixed geometry and inclination angle, both IPG base case curves and the actual curve share a very similar slope. This behavior demonstrates a direct link between changes in pit gain and changes in surface pressure which is a fundamental concept in this research. Furthermore, the difference in the accuracy of the base case prediction for the behavior of surface indicators when gas is completely in a fixed geometry versus in multiple geometries highlights the sensitivity of the prediction to gas slip velocity and distribution throughout the wellbore.

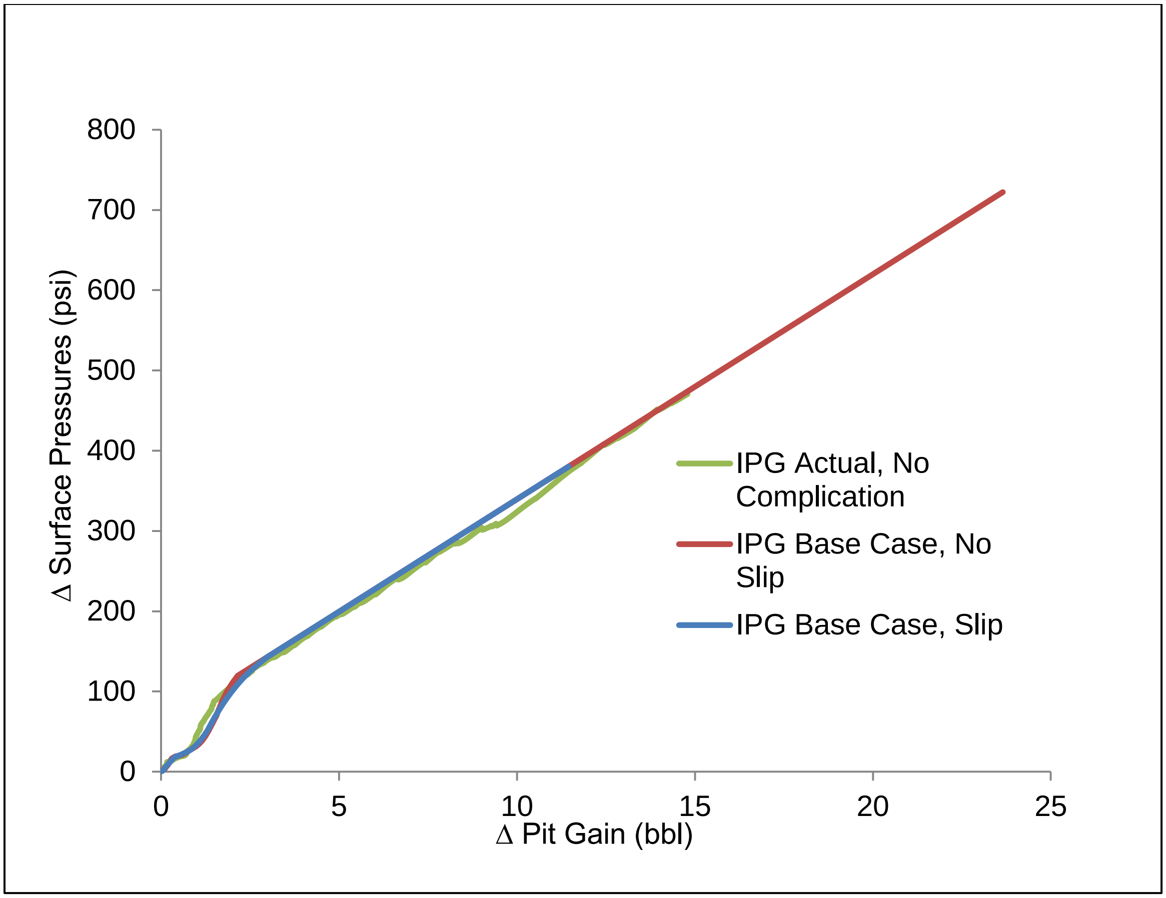

Figure10: IPG model base case (slip and no-slip) versus simulation

9 Simulation Case Matrix

The complications that will be investigated are listed in a matrix categorized by the initial conditions and the complication conditions being modeled. The simulation matrix is shown directly below in Table 3. This chart reads from left to right. Each of the complication scenarios will be simulated with the SPT Drillbench Software. The simulation results will be analyzed for unique attributes that can facilitate the diagnosis of complications.

Table 3: Simulation case matrix for complications

	Initial Conditions		Complication Conditions	
Category	**Influx Response Strategy**	**Formation Characteristics**	**Complication**	**Consequence**
Annulus Side	Constant Pump Pressure	GFF<GF	Partial Choke Plugging, no remediation	Lost Circulation
				Wellbore Intact
			Choke Washout/RCD/BOP Leak	Additional Influx
				Wellbore Intact
			Passive Loss of Choke Control (Inadequate Pressure)	Additional Influx
				Wellbore Intact
			Choke Plug with blockage cleared	Additional Influx
				Lost Circulation
				Lost Circulation and Additional Influx
				Wellbore Intact
			Choke Plug, Re-route	Lost Circulation
				Wellbore Intact
Injection Side	Constant Pump Pressure	GFF<GF	Plugged Single Nozzle	Additional Influx
				Wellbore Intact
			Nozzle Washout	Lost Circulation
				Wellbore Intact
			Drill String Leak/Part	Lost Circulation
				Wellbore Intact
			Pump Inefficieny	Lost Circulation
				Wellbore Intact
Formation Complication	Constant Pump Pressure	GFF<GF	Exceed Kick Tolerance	Simultaneous Downhole Loss & Influx
		GF>GFF	Influx will never stop	Simultaneous Downhole Loss & Influx
	Equal Flow Rates	GF>GFF	Influx will never stop	Simultaneous Downhole Loss & Influx

The initial conditions segment of the case matrix is separated into two subcategories listed as influx response strategy and formation characteristics. The influx response strategy column describes whether or not the choke operator circulates the influx out of the wellbore by maintaining a constant pump pressure or in one case, continuously forcing flow rates to be equal. The latter will be used in one simulation to illustrate a point and is not considered a recommended practice. The formation characteristics column compares the relative magnitudes of pore and fracture pressure gradients in the weak zone and high pressure zone. Most cases will be simulated with GFF<GF, meaning that the weak zone, fracture pressure gradient is greater than the high pressure zone, pore pressure gradient. However, two scenarios are the opposite, GFF<GF. These simulations were performed to replicate past work by Das which addressed exceeding kick tolerance in a simplified fashion.

The two complication condition subcategories list the type of complication and ultimate consequence of such a complication occurring. The types of complications consist of plugging and leaks in the annulus and drill string, bit, and mud pump as well as operator errors and exceeding kick tolerance. Finally, the consequence of the complication involves whether or not the complication or the response to the complication has caused lost circulation, an additional influx, simultaneous downhole losses and influx, or simply a sustained and unintended change in wellbore pressure.

10 Simulations of Injection Side Complication Simulations

The Drillbench Kick software has been used to simulate complications such as mud pump inefficiency, nozzle washout and plugging, and drill string leak and part. The resulting data from these simulations will be used to create IPG actual case plots for Well X. The strategies used to model complications assume that an operator or automated choke system will continuously adjust choke size when possible in an effort to maintain pump pressure at a desired target value. Also, geometry changes cannot be made in the midst of simulations with Drillbench Kick. Thus, drill string part/leak and bit plugging/washout scenarios were created by concatenating the raw data from simulations with a pre-complication geometry and a post-complication geometry. Finally, IPG actual curves will only be compared against IPG base case predictions with a no slip model to simplify the plots.

10.1 Plugged Bit Nozzle

In the event of a plugged nozzle, drill string pressure has traditionally been expected to increase due to the reduced flow area in the drill bit. Conversely, the choke pressure is expected to remain relatively stable until it is adjusted. Thus, if the occurrence of a plugged nozzle is not recognized during a CBHP kick circulation, an operator or automated system is expected increase the choke size opening in order to keep pump pressure stabilized at the target value. This response will cause an unintended drop in BHP. If BHP falls low enough, an additional influx may be taken.

10.1.1 Additional Influx

The plugged nozzle and additional influx scenario was modeled by concatenating the raw data from a pre-nozzle plug and post-nozzle plug simulation. The pre-nozzle plug simulation involved a successful kick circulation with four 11/32” bit nozzles until the time of 2000 seconds was reached. At this point the pre-nozzle plug simulation was stopped. Next, a post-nozzle plug simulation was initiated consisting of a drill bit with only three 11/32" bit nozzles. The pump pressure was 230 psi higher in this simulation due to the increased flow restriction through the bit. At 2000 seconds into the post-nozzle plug simulation, the choke was opened by 4% to allow pump pressure to drop back down to its pre-nozzle plug target value. The data following the 2000 second mark on the post-nozzle plug simulation was appended to the pre-nozzle plug scenario at the same point in time in order to replicate the entire plugged nozzle event as shown in Figure11.

Figure11 shows a quick increase in pump pressure which marks the onset of the nozzle plug. The subsequent drop in choke pressure to correct for the increase in pump pressure causes an additional influx as evidenced by the consistent increase in pit gain and flow out.

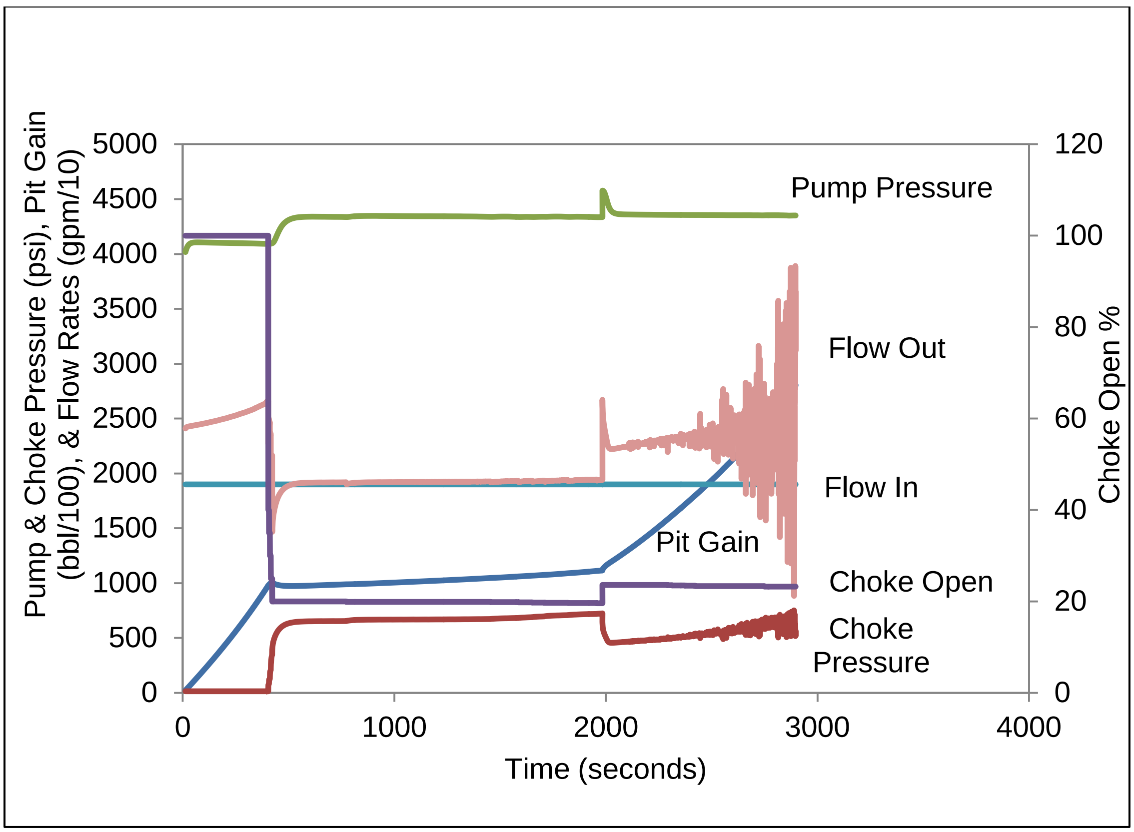

Figure11: Key indicators plot for a plugged nozzle with an additional influx

Figure 12 illustrates the IPG plot for the current scenario. At a Δ pit gain of roughly 2 bbl, the IPG actual curve deviates downward from the IPG base case curve by showing a drastic drop in Δ surface pressures attributed to the adjustment in choke size. There is a minor upward correction in the curve following the drastic drop in Δ surface pressure associated with a continued drop in pump pressure due to lag time after choke pressure has already stabilized. Around this time, BHP falls low enough to initiate the second influx as evidenced by the shallower slope of the IPG actual curve and continued progression towards a positive Δ pit gain. The IPG actual case has a shallower slope than the IPG base case due to the application of insufficient choke pressure to account for both the underbalance and continued loss in hydrostatic pressure. The simulation was halted when the mixture volume reached 3200' MD due to a simulation error. Otherwise, a larger Δ pit gain would have been expected in this event.

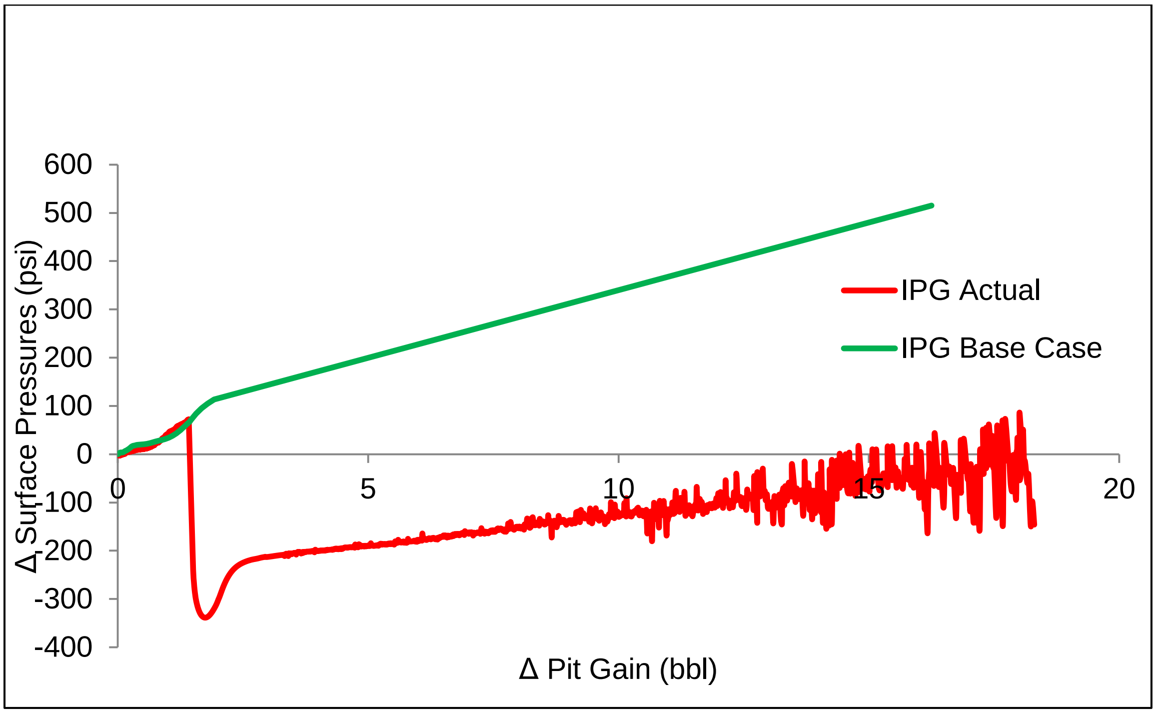

Figure 12: IPG plot of base case vs. plugged nozzle with an additional Influx

10.1.2 No Additional Influx

The plugged nozzle and no additional influx scenario was modeled in a similar manner to the plugged nozzle with an additional influx except for the fact that a higher than required pump pressure was held upon stopping the influx. This additional overbalance allowed wellbore pressure to be high enough to prevent an additional influx following the onset of a plugged nozzle complication.

In accordance with Figure13, at 2500 seconds, a 1.45% increase in choke size opening caused choke pressure to fall and flow out and pit gain to increase drastically. The increase in choke opening was designed to offset the sudden increase in pump pressure due to onset of a nozzle plug. The target pump pressure was achieved and a CBHP kick circulation was continued.

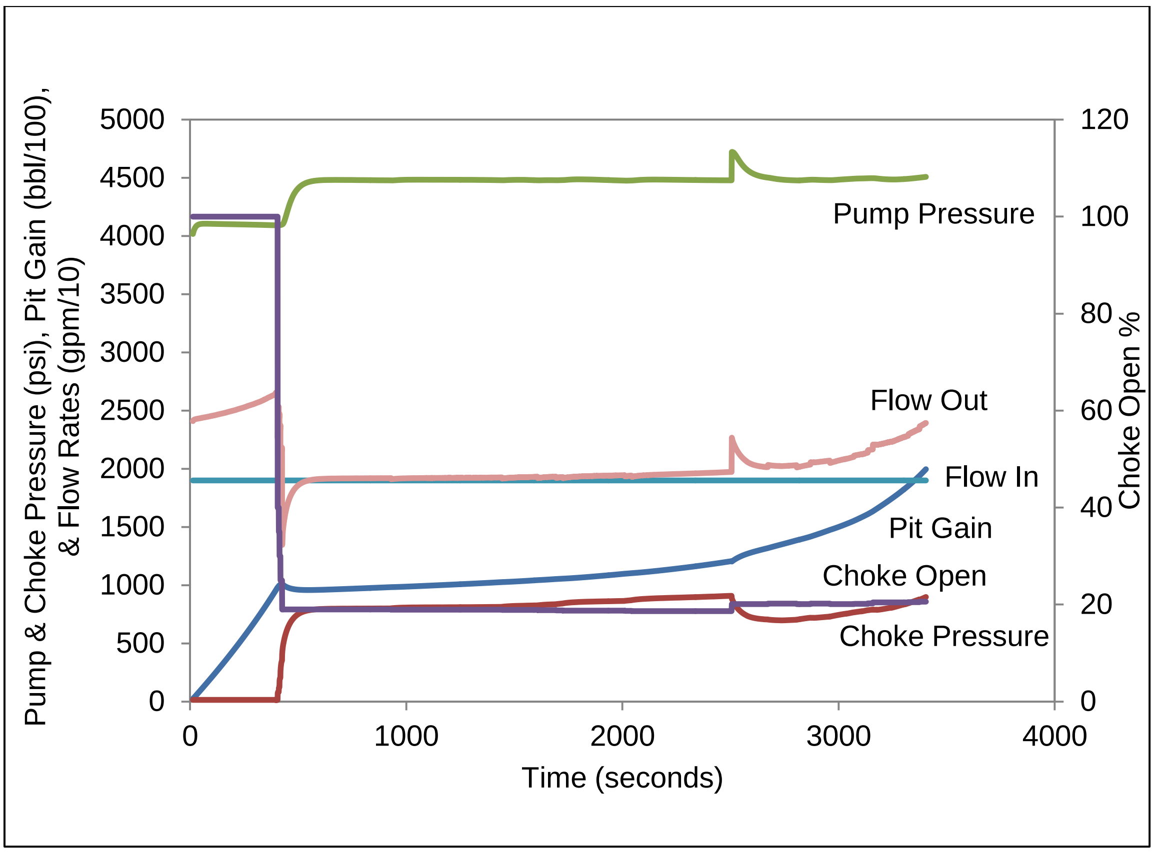

Figure13: Key indicators plot for a plugged nozzle with no additional influx

Figure 14 illustrates the IPG plot for the current complication scenario. At a ∆ pit gain of roughly 2.25bbl, the IPG actual case plot deviates from the IPG base case by showing a drastic drop in ∆ surface pressures attributed to the pump pressure spike and subsequent response to increase in choke size. The relatively sharp corner of the IPG actual curve at the minimum ∆ surface pressure is indicative of the resulting change in pump pressure being zero and a net decrease in choke pressure. With the target pump pressure obtained once more, the slope of the IPG actual case is roughly parallel to the IPG base case indicating that the increase in choke pressure is once again a predictable function of the loss in hydrostatic pressure from the existing influx in the well. This behavior indicates that the well has sustained a reduction in BHP without any additional influx. The simulation was halted when the mixture volume reached 1200' MD due to a simulation error. Otherwise, a larger ∆ pit gain would have been expected in this event.

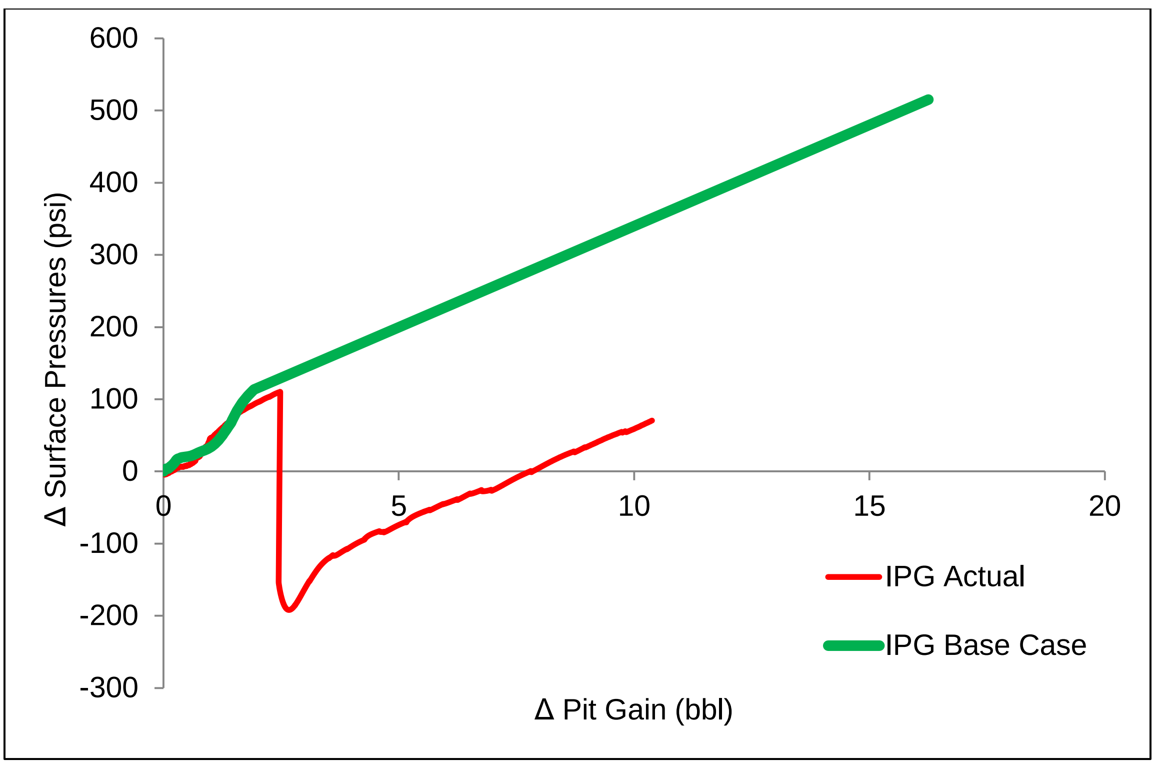

Figure 14: IPG base case vs. plugged nozzle with no additional influx

10.2 Inefficient Pump

The flow rate injected into the wellbore by the mud pump is reduced to simulate an inefficient or leaking pump. As a result of this, pump pressure will have tendency to fall due to the reduction of circulating frictional pressure losses. If the occurrence of a leaking pump is not recognized, an operator may begin to offset this reduction in pump pressure by decreasing choke size and ultimately increasing both choke pressure and pump pressure. Depending on the proximity of wellbore pressure to the fracture pressure, this increase in choke pressure could potentially cause lost circulation.

Please note that the reduction in frictional pressure losses in the drill string is normally greater than the reduction in frictional pressure losses in the annulus in the event of pump inefficiency. This difference in pressure loss is attributed to smaller flow area within the drill string as compared to the annulus. As a result, applying choke pressure to offset the entire reduction in frictional pressure loss from an inefficient pump will overcompensate for the loss in BHP. This over compensation may cause formation fracture.

10.2.1 Lost Circulation

Choke size was reduced to offset the pump pressure drop associated with a drop in flow rate into the wellbore to simulate a scenario with a leaking pump resulting in lost circulation. The leaking pump was modeled by a drop in flow rate from 190 gpm to 171 gpm. To compensate for the drop in pump pressure, the choke restriction was reduced from 24.35% to 15% as shown in Figure 15 at 1700 seconds.

This choke size adjustment should have been adequate to increase pump pressure back up to its target value. However, the magnitude of the BHP increase caused the formation to fracture at a pump pressure of 3900 psi, 77 psi below the target pump pressure value. At this point, pump pressure could not be increased to the target value of 3977 psi because wellbore pressure was limited by the formation fracture pressure and lost circulation was occurring.

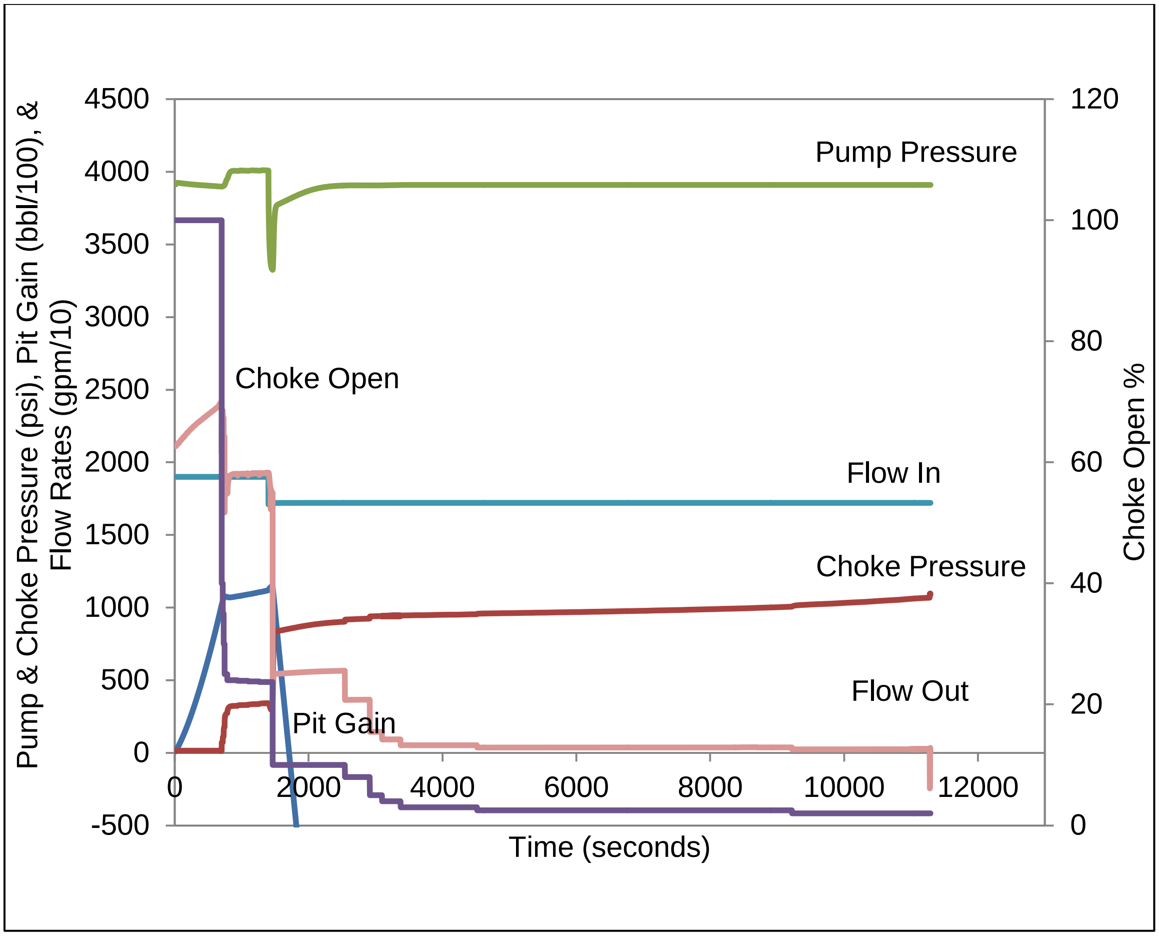

Figure 15: Key indicators plot for inefficient pump and lost circulation

Figure 16 demonstrates a deviation between the IPG actual and IPG base case curves at a Δ pit gain of .6 bbl. This deviation is the result of a rapidly increasing choke pressure aimed at trying to maintain a stabilized pump pressure following the onset of the pump inefficiency. Due to the increased choke pressure, Δ pit gain proceeds toward negative values due to gas compression and ultimately lost circulation. At roughly 800 psi of Δ surface pressure, the IPG actual curve experiences a short correction followed by a relative stabilization in pressures once wellbore pressure has been increased enough to fracture the formation. As the influx migrates above the weak zone, choke pressure may increase to offset the loss in hydrostatic pressure above the weak zone.

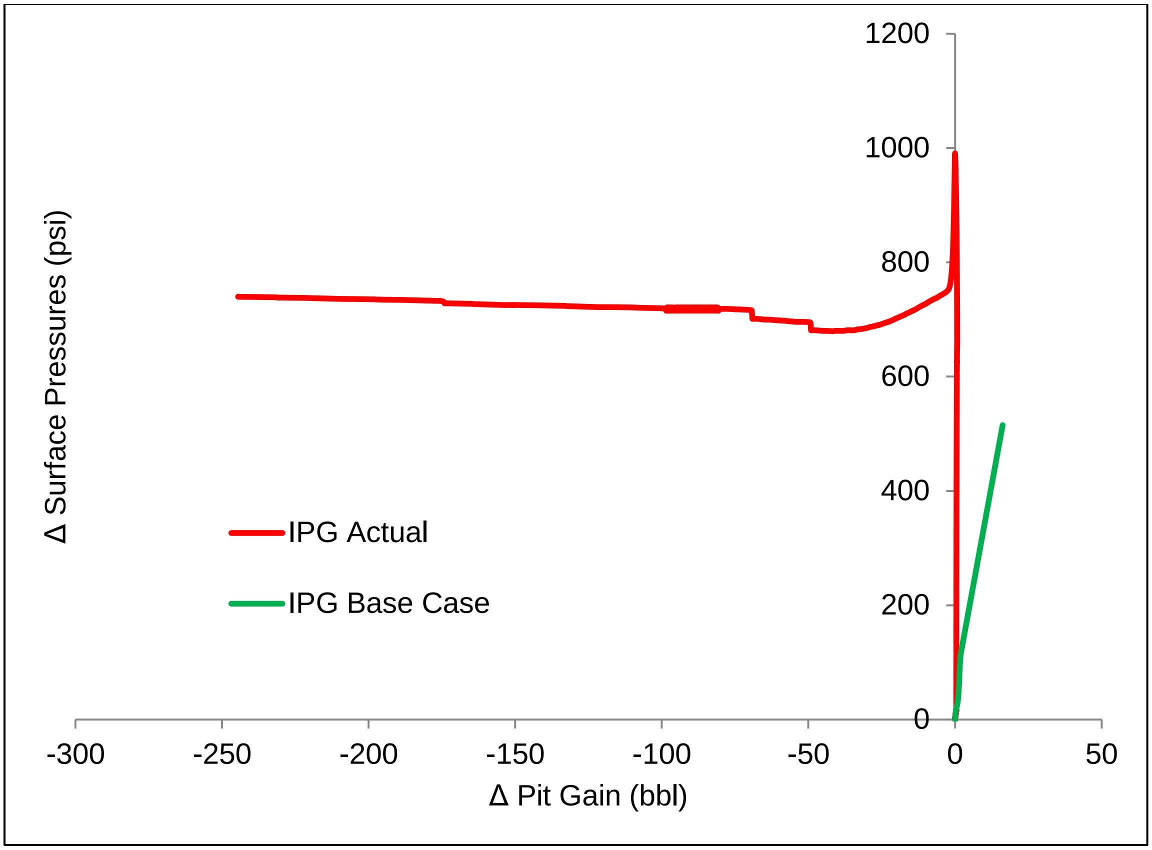

Figure 16: Implied pit gain plot for inefficient pump and lost circulation

10.2.2 Wellbore Intact

An inefficient pump with an intact wellbore is shown in Figure 17, at 1525 seconds. At this point in time, the pump rate was reduced from 190 gpm to 180.5 gpm and the choke size was decreased from 21.2% to 18.1% to increase BHP and thus, compensate for the drop in pump pressure. This adjustment caused wellbore pressure to increase by 415 psi. Given the margin between wellbore pressure and fracture pressure, this increase in choke pressure did not cause lost circulation. Instead, the abrupt change in choke size caused flow out of the wellbore to demonstrate a transient, downward spike attributed to gas compression. Following this event, the wellbore pressure momentarily stabilized allowing for a constant pump pressure circulation to commence once more at a higher BHP.

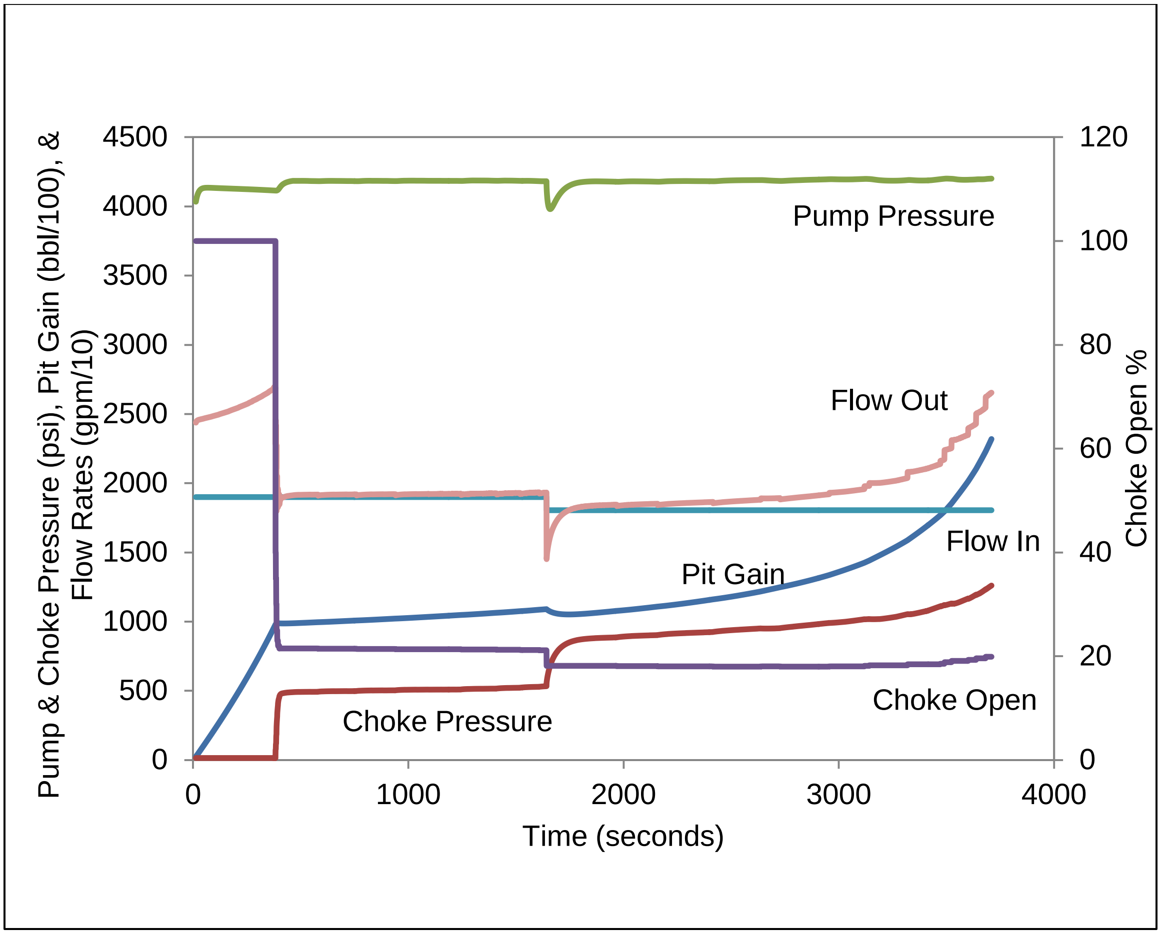

Figure 17: Key indicators plot for inefficient pump with an intact wellbore

Figure 18 depicts the IPG Plot for an inefficient pump with an intact wellbore. This plot demonstrates an increase in Δ surface pressures of 415 psi coupled with a compression of the gas influx by a half barrel due to the abrupt choke size reduction. Following the rapid rise in Δ surface pressures and small reduction in Δ pit gain, the IPG actual plot resumes a slope that is similar to the IPG base case. A return of the IPG base case slope to the predicted slope suggests that changes in surface pressure are linked to changes in pit gain once in the wellbore. In such circumstances the wellbore is considered to be intact.

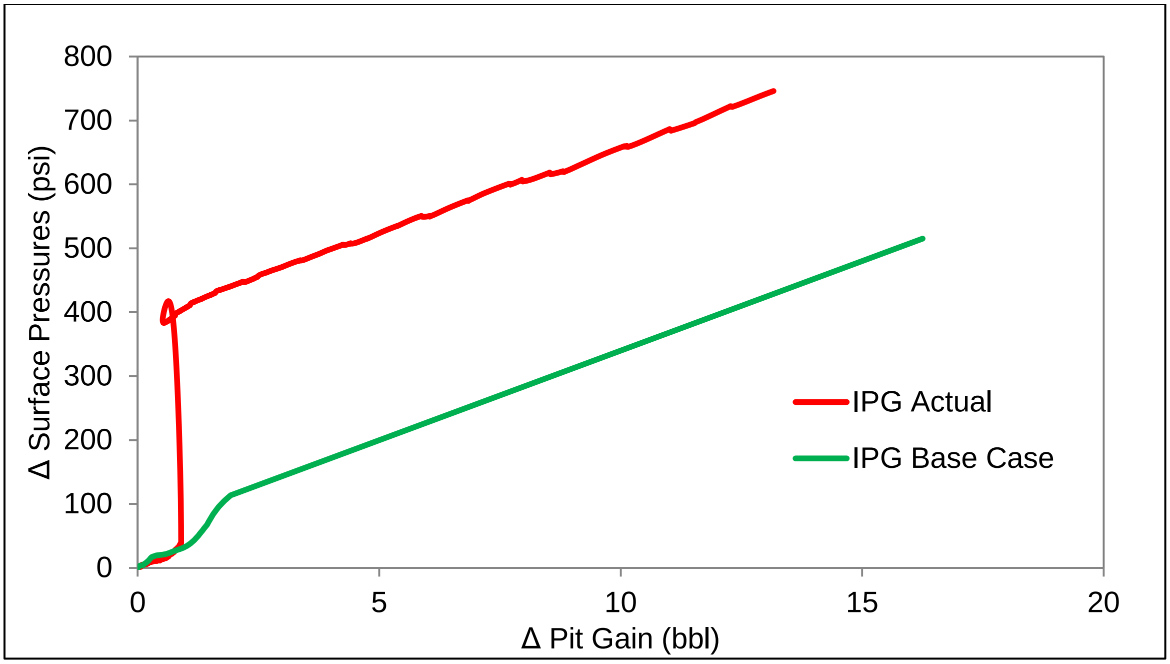

Figure 18: IPG base case versus inefficient pump complication with an intact wellbore

10.3 Nozzle Washout

A significant pressure drop across a bit nozzle can cause the nozzle to erode over time or the retainer to fail allowing the nozzle to separate from the bit. Without the nozzle in position, the flow area through the bit is increased resulting in a decreased pressure drop across the bit. This decrease in pressure loss may cause pump pressure to fall. However, if an operator or automated system does not recognize that a nozzle washout has occurred, the resulting drop in pump pressure may be offset with a decrease in choke size. The resulting increase in choke pressure will cause wellbore pressure to increase. Depending on the margin between wellbore pressure and fracture pressure, the resulting increase in choke pressure may cause lost circulation.

10.3.1 Lost Circulation

The nozzle washout simulation shown in Figure 19 represents a scenario where a nozzle has become loose over a period of time and is finally dislodged from the drill bit in its entirety. To simulate this event, pre-washout and post-washout simulations were performed. The pre-washout simulation was run without any complications until a time of 1750 seconds was reached utilizing a bit with four 11/32" nozzles. Next, a post-washout simulation was designed with three 11/32" nozzles and a fourth 28/32" nozzle size to replicate the washout and subsequent drop in pump pressure of 250 psi. At 1750 seconds into the post-washout simulation, choke size is reduced by 4.1% in order to increase pump pressure back to the target value in the pre-nozzle washout simulation. Finally, pre-nozzle and post-nozzle simulations were concatenated at the 1750 second mark to represent the full nozzle washout scenario.

One should note that the increase in BHP associated with the choke size reduction at 1750 seconds caused the wellbore to fracture at a pump pressure that is 25 psi below the target value. Going forward, additional choke size reductions were made with no success in increasing pump pressure to the target value. However, choke pressure increased gradually during the simulation to offset the loss in hydrostatic pressure above the weak zone from the gas influx.

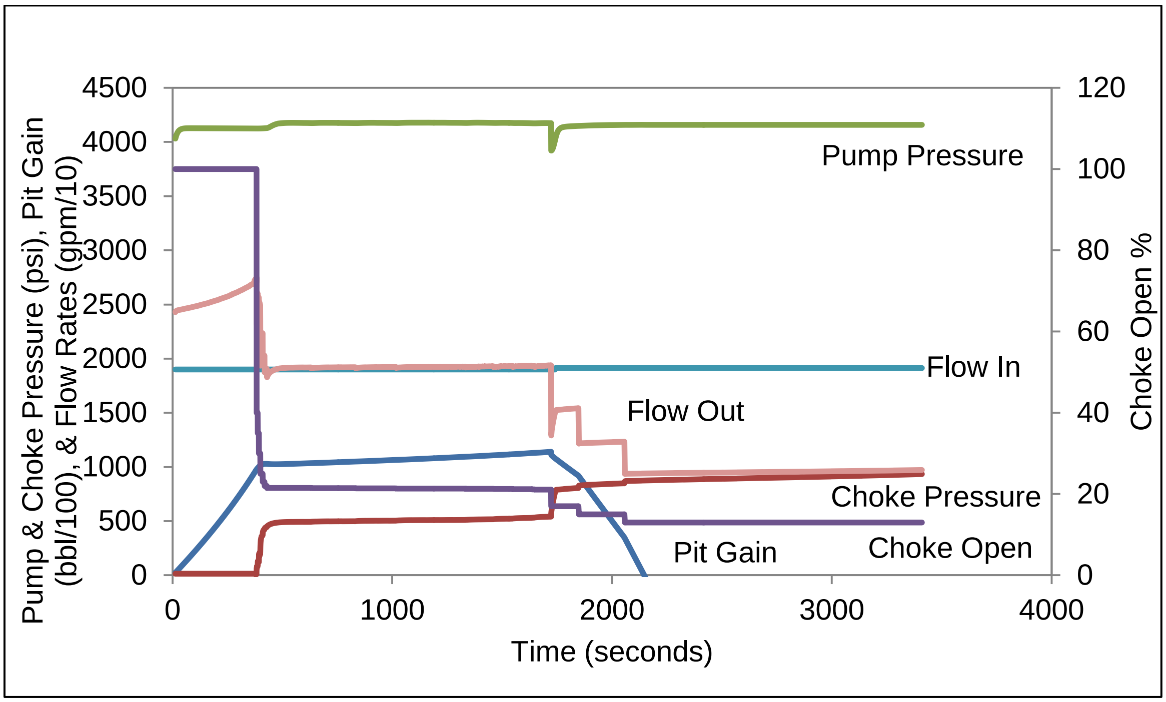

Figure 19: Key Indicators Nozzle Washout with Lost Circulation

According to the IPG actual plot, Figure 20, the onset of a nozzle washout is depicted at roughly 1 bbl Δ pit gain where the Δ surface pressures increased abruptly due to a reduction in choke size aimed at trying to regain the originally intended target pump pressure. However, due to fracturing the formation, pump pressure stabilized at a value below the target and choke pressure grew at a reduced rate to compensate for loss in hydrostatic pressure above the weak zone due to the gas influx. As a result, the Δ surface pressures exhibit a mild increase in the near term. The initiation of lost circulation also caused the IPG actual curve to progress continuously toward a negative Δ pit gain.

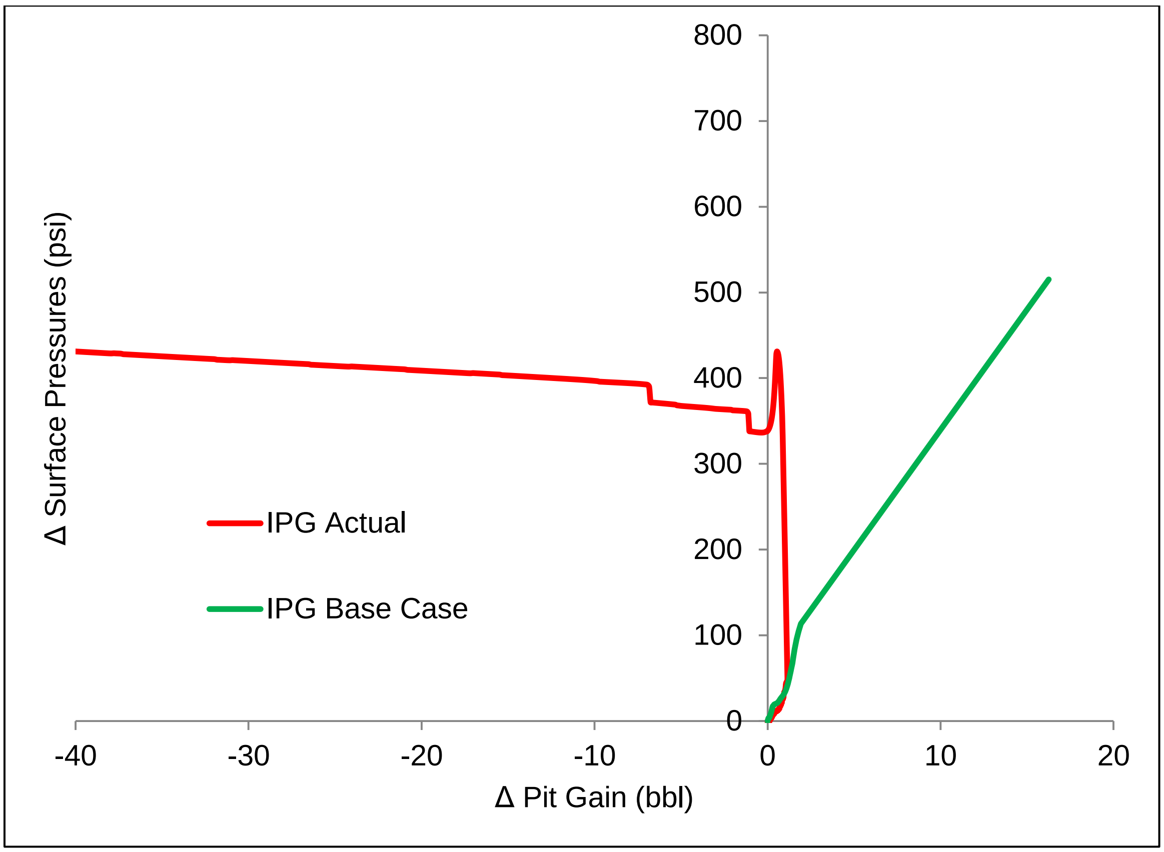

Figure 20: Implied pit gain plot for nozzle washout with lost circulation

10.3.2 Wellbore intact

The nozzle washout with no lost circulation scenario was modeled in a similar manner to the previous scenario except for the fact that fracture pressure was increased so that lost circulation would not occur. The key indicators plot, Figure 21 depicts a choke pressure increase due to a 2.25% choke size decrease at 1600 seconds. The choke size changes were performed to offset the drop in pump pressure due to a bit nozzle washout. With the target pump pressure obtained once more, a constant pump pressure kick circulation was resumed for the remainder of the simulation.

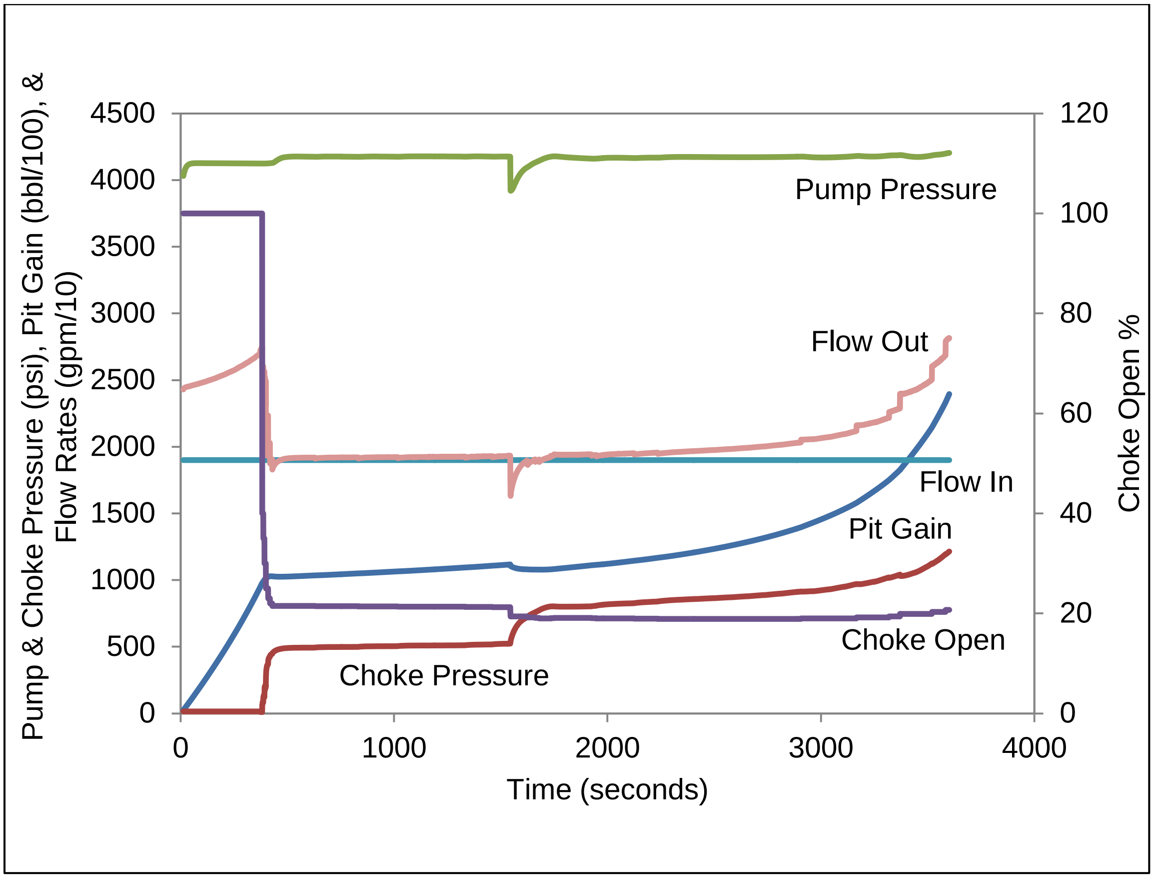

Figure 21: Key indicators plot for a nozzle washout, wellbore intact

The IPG actual case, Figure 22, depicts the behaviors of a nozzle washout as a sharp increase in Δ surface pressures at a 1bbl of Δ pit gain. The sharp increase is attributed to the rise in choke pressure needed to return pump pressure to its target value following the onset of the nozzle washout. Following the abrupt, upward change in ∆ surface pressures, the IPG actual curve returns to the previously predicted IPG base case slope while continuously progressing toward a positive ∆ pit gain. These behaviors in surface indicators suggest a kick circulation in an intact wellbore with a sustained increase in BHP.

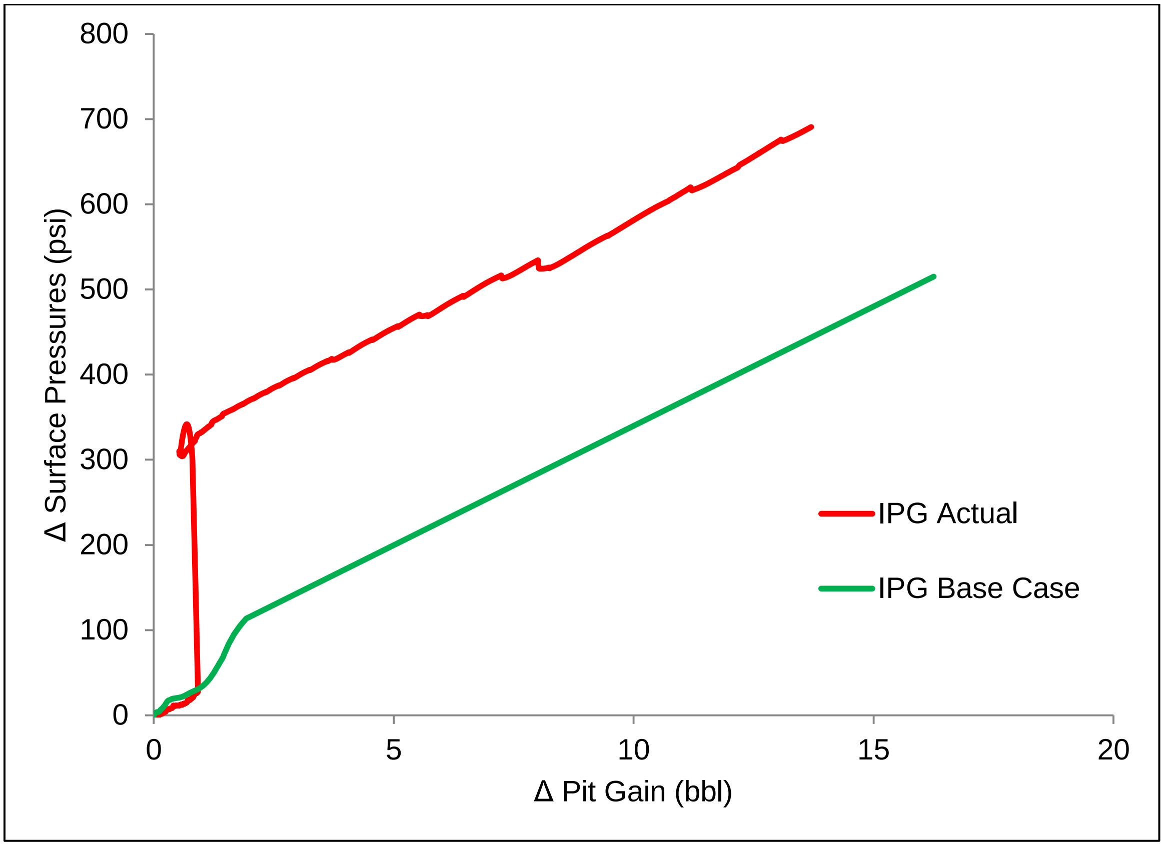

Figure 22: IPG plot for a nozzle washout with an intact wellbore

10.4 Drill String Washout or Parting, near the Drill Bit

A drill string washout can cause significant drop in frictional pressure losses as not all of the drilling fluid is being circulated through the entire drill string. Instead, some of the flow is diverted toward the annulus at the depth of the washout. A drill string washout typically begins with leak in the drill string that partially diverts flow until widening enough to cause the drill string to part. This research will explore a drill string washout that has parted near the bit.

A drill string leak begins to manifest itself by a slowly falling pump pressure as the flow of drilling fluid is diverted through the leak. In response to the falling pump pressure, a choke operator may reduce choke size to force pump pressure back to the target value. However, the flow of drilling fluid through the leak zone can cause further erosion allowing the leak to widen and pump pressure to continue to fall. Once more, choke size is reduced. This continuous behavior in pump pressure is expected to occur until the drill string suddenly parts. This event is marked by a sudden and final drop in pump pressure. Once a choke size reduction is made to account for the parted drill string, pump pressure becomes relatively constant indicating that the flow path of drilling fluid through the wellbore has stabilized. The reductions in choke size associated with a drill string washout can increase wellbore pressure enough to cause lost circulation.

10.4.1 Drill String Washout, Lost Circulation

A drill string washout with lost circulation was modeled with four concatenated simulations that represented the loss of circulating friction associated with a growing leak. The first simulation represented a complication-free kick circulation. Simulations two through four represented the change in flow geometries associated with a growing leak. The change in flow geometry was modeled by incrementally increasing the flow area through the bit. Simulations two through four each had an abrupt choke size reduction to account from the loss in circulating friction associated with a growing leak and subsequent washout. However, the choke size reduction associated with simulation four increased wellbore pressure high enough to induce lost circulation. This event occurred before the drill string could fully part.

The simulations were joined in the following manner. Simulation one was truncated at the onset of the leak. At this point in time, a choke size reduction in simulation two was made to correct pump pressure due to the leak. Simulation two was truncated after the pump pressure returned to its target value. Simulations one and two were adjoined at the point in time at which the drill string washout began. This process was repeated for simulations three and four using the moment in time at which pump pressure returned to the target value as a concatenation point.

The key indicators plot, Figure 23 represents the onset of a drill string leak at 1800 seconds. The onset of the leak is depicted by a gradual drop in pump pressure followed by a correction created by a reduction in choke size to force pump pressure upward. As the hole widens, this behavior is repeated. However, due to lost circulation, pump pressure cannot be increased high enough to return to the target value as seen at 2600 seconds. Lost circulation is evidenced by the continued decrease in pit gain and drop in flow out below flow in for the remainder of the circulation. As the influx nears the surface, choke pressure will increase to offset the loss in hydrostatic pressure above the weak zone despite the occurrence of lost circulation.

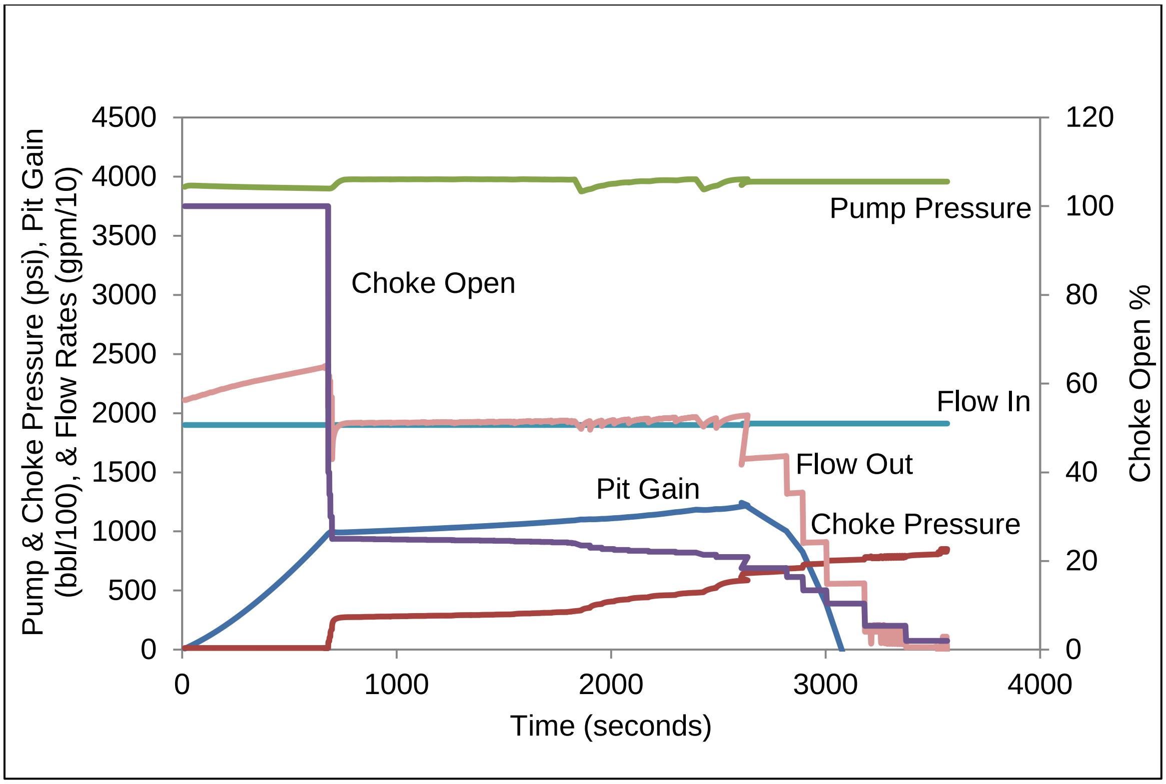

Figure 23: Key indicators plot for drill string washout near the bit, lost circulation

The implied pit gain plot, Figure 24 depicts the onset of a drill string washout at 1 bbl of Δ pit gain in which the IPG actual plot deviates upward from the base case. This behavior is demonstrated by the stepwise change in Δ surface pressure associated with the growing leak and associated choke size reduction to correct pump pressure. At 2.5 bbl of Δ pit gain, wellbore pressure has been increased high enough to induce lost returns as evidenced by the continuous progression of the IPG actual curve toward a negative Δ pit gain with a relatively horizontal slope. During this period of lost circulation, choke pressure grew gradually as gas was circulated above the weak zone and pump pressure stabilized below the target pressure as wellbore pressure could not be increased any further.

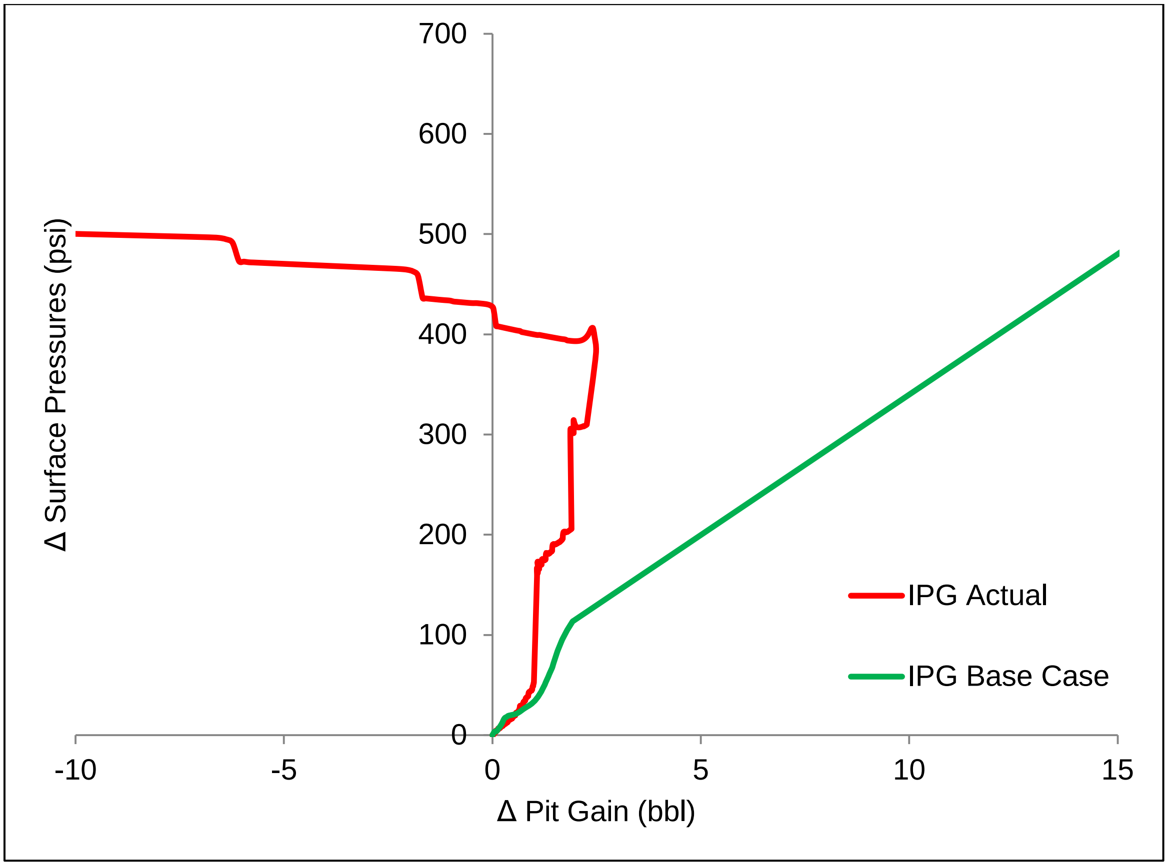

Figure 24: Implied pit gain plot for drill string washout near the bit, lost circulation

10.4.2 Drill String Washout and Part, Wellbore Intact

The key indicators plot, Figure 25 represents the same data from the drill string leak in the past section plus a fifth simulation to represent a full drill string part at 3350 seconds. There are no further drops in pump pressure following the drill string part. This is evidence that there is no longer the presence of a continuously growing leak. The drop in pump pressure due to the drill string parting would have been more severe than demonstrated on the graph if the mixture volume was closer to the base of the well. However, at the time the washout occurred, rapidly expanding gas near the surface was increasing flow rate through the choke causing an increase in both choke pressure and BHP. Thus, the loss in circulating friction from the washout was partially offset by the increase in BHP from the rapidly expanding gas. Nonetheless, the return of pump pressure to the target value and consistently growing pit gain, flow out, and choke pressure all offer evidence that the wellbore is intact.

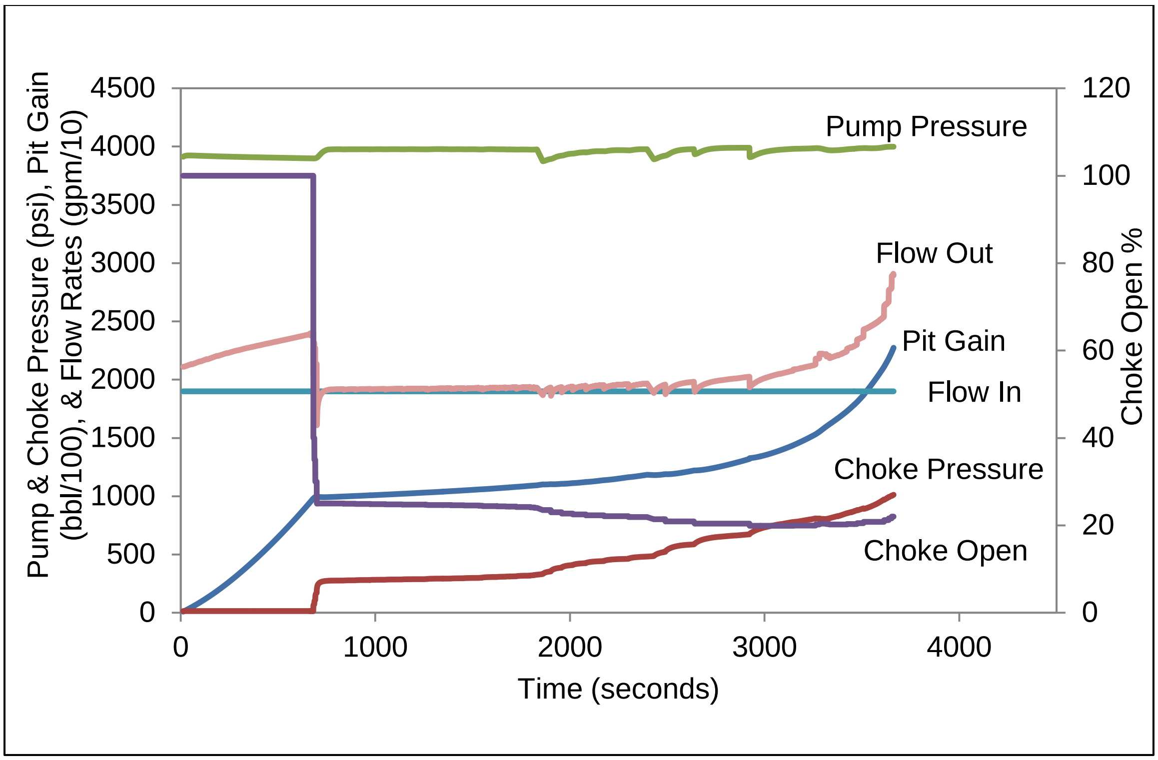

Figure 25: Key indicators plot: drill string washout and part near the bit, wellbore intact

The implied pit gain plot, Figure 26 depicts the onset of the washout at 1 bbl of Δ pit gain in which the IPG actual plot deviates upward from the base case. This behavior is demonstrated by the stepwise change in Δ surface pressures associated with the growing leak and associated choke size reduction to correct pump pressure. At 3 bbl Δ pit gain, the increase in Δ surface pressures stop and the IPG actual curve continues to progress toward positive Δ pit gain with a slope that is similar to the predicted base slope. This behavior in the IPG actual curve suggests that a parted drill string has occurred and a CBHP kick circulation has resumed without lost returns.

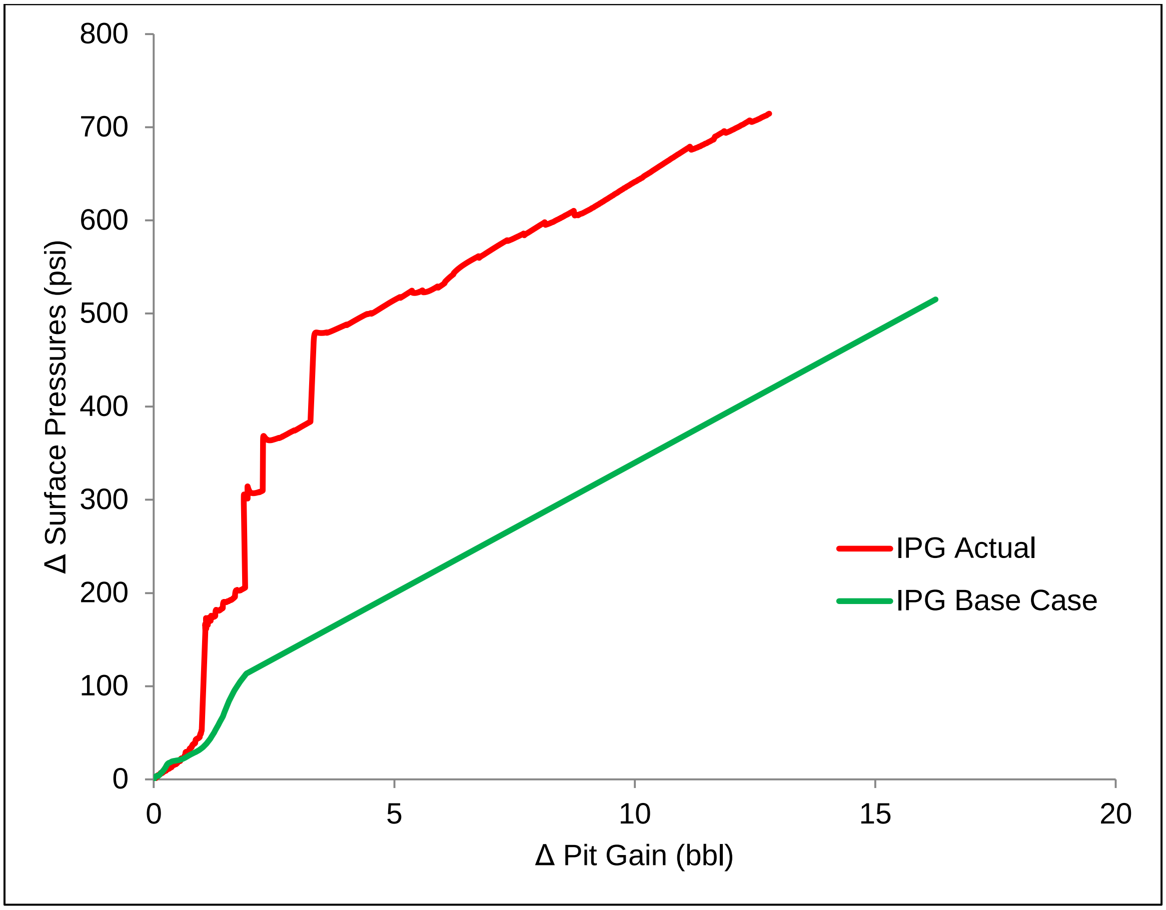

Figure 26: IPG plot for drill string washout and part near the bit, wellbore intact

11 Simulations of Annulus Side Complication Simulations

The Drillbench Kick software has been used to simulate complications such as a partially plugged choke, leaking choke/RCD, and a passive loss of choke control. The resulting data from these simulations will be used to create IPG actual plots for Well X. Choke opening will be modified in the midst of a simulation in an effort to simulate plugging, leaking, or loss of choke control. Finally, IPG actual curves will only be compared against IPG base case predictions with a no slip model to simplify the plots.

11.1 Partially Plugged Choke

Three partially plugged choke scenarios have been designed to represent a flow restriction in the choke induced by an accumulation of solids. A blockage in the choke system will increase back pressure on the annulus and subsequently drive pump pressure upward as well. Depending on the margin between wellbore pressure and fracture pressure, these scenarios may result in lost circulation at the onset of the blockage. One of the scenarios explores cases where choke size is not modified following the blockage. As a result, the pump pressure increases without being corrected. A second scenario will depict an event where the choke is opened widely in an effort to clear the blockage. This scenario has the potential for lost circulation at the onset of the plug followed by the potential for an additional influx after the blockage is cleared. A third scenario explores an event where flow is re-routed through another choke following the occurrence of a blockage. This scenario may result in lost circulation at the onset of the blockage.

11.1.1 No Remediation, Wellbore Intact

The key indicators plot, Figure 27 describes the gradual onset of a partially plugged choke between 2050 – 2300 seconds. During this time, the effective choke size is continuously reduced causing choke pressure to increase. The resulting impact of this choke size adjustment is an increase in BHP that also causes a rise in pump pressure. During the 250 seconds following the onset of the partially plugged choke, flow out and pit gain temporarily decline as the increase in wellbore pressure caused the gas influx to compress. However, once the flow geometry through the choke stabilized; flow out and pit gain also began to increase once more due to a continuation of gas expansion.

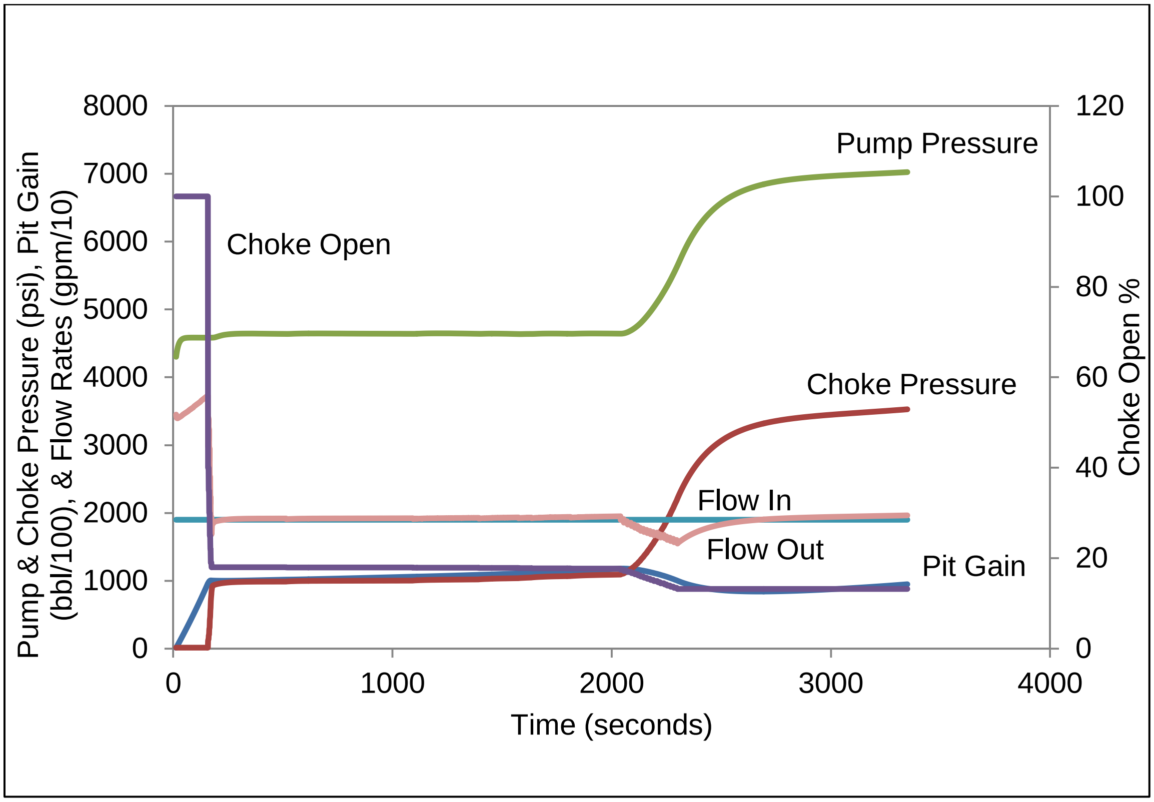

Figure 27: Key indicators for a choke plugging without remediation & an intact well

The IPG actual Plot, Figure 28 depicts the gradual onset of a partially plugged choke at a Δ pit gain of 2 bbl with an upward deviation of the IPG actual curve. At this point, Δ surface pressures are dominated by a rapid increase in choke pressure attributed to the reduction in choke size opening. Next, a reversal of the Δ surface pressures curve in the downward direction is indicative of a lagged pump pressure increase. As a result of the blockage, wellbore pressure is increased causing the gas influx to compress as shown by the Δ pit gain dropping from 2 bbl to as low at -2 bbl.

However, following the compression, the IPG actual curve resumes a slightly steeper slope than the base case as the influx begins to gradually expand once again as circulation toward the surface continues. This behavior indicates that the wellbore is intact. The simulation was halted when the mixture volume reached 1700’ MD due to a simulation error. Otherwise, a larger ∆ pit gain would be expected in this event.

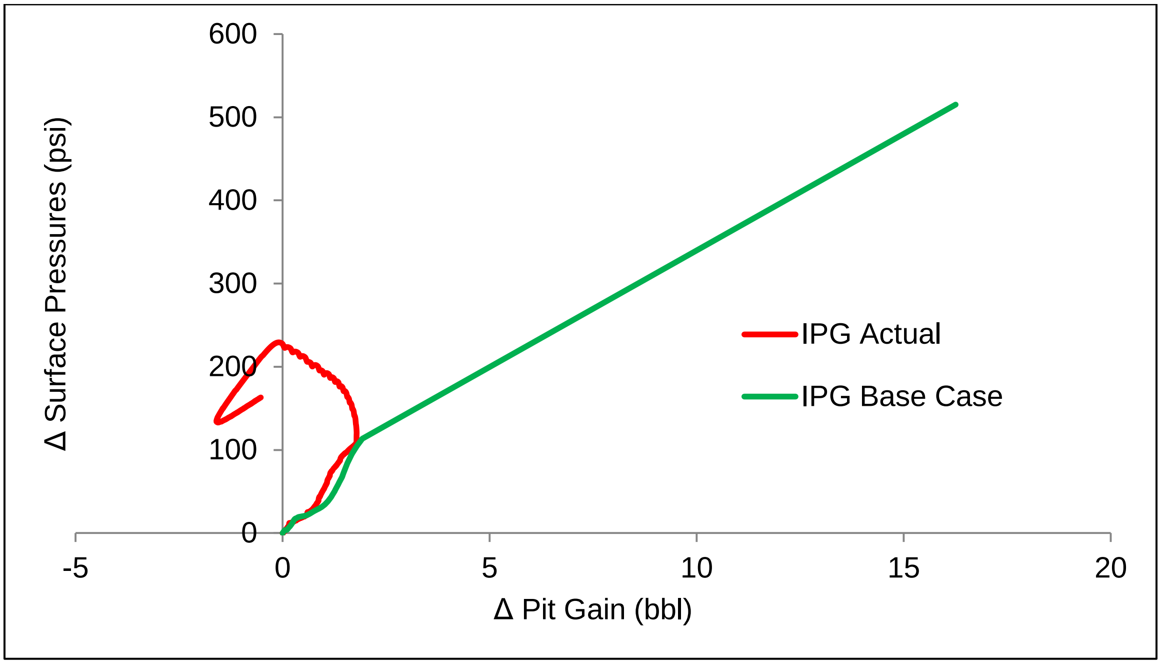

Figure 28: IPG plot for a choke plugging with no remediation and an intact wellbore

In this scenario, gas expansion continues when the mixture volume is near the surface of the wellbore. As a result, flow rate out of the wellbore increases at rapid rate through a fixed choke size thereby driving both choke pressure and pump pressure upward. However, pump pressure increases at a lower rate than choke pressure because of the reduction in hydrostatic pressure in the annulus from gas expansion. As consequence to this, the IPG actual slope is mildly steeper than the IPG base case slope due to a slowly increasing BHP. Despite the slow increase in BHP, there are no symptoms of lost circulation because the IPG actual plot progresses toward a consistently increasing pit gain.

11.1.2 Intact Wellbore and Re-route to Alternate Choke

A partially plugged choke in an intact wellbore in combination with a re-routing of flow through an alternate choke is performed in this simulation. The re-routing is an attempt to correct the increase in pump pressure associated with the blockage.

To create this event, Figure 29 demonstrates how choke size is reduced from 17.4% to 15.4% to simulate a blockage in the choke and an increase in BHP and pump pressure at 1350 seconds. Following the increase in pump pressure, the choke size in the simulator is returned to 17.4% at 1850 seconds in effort to simulate the diversion of flow to a fully functional choke system. Given the margin between wellbore pressure and fracture pressure, the increase in BHP was not enough to cause lost circulation in this scenario. Instead, there was a transient decrease in pit gain due to gas compression. Once the flow was re-routed, gas continued to expand and a constant pump pressure was held with the alternate choke.

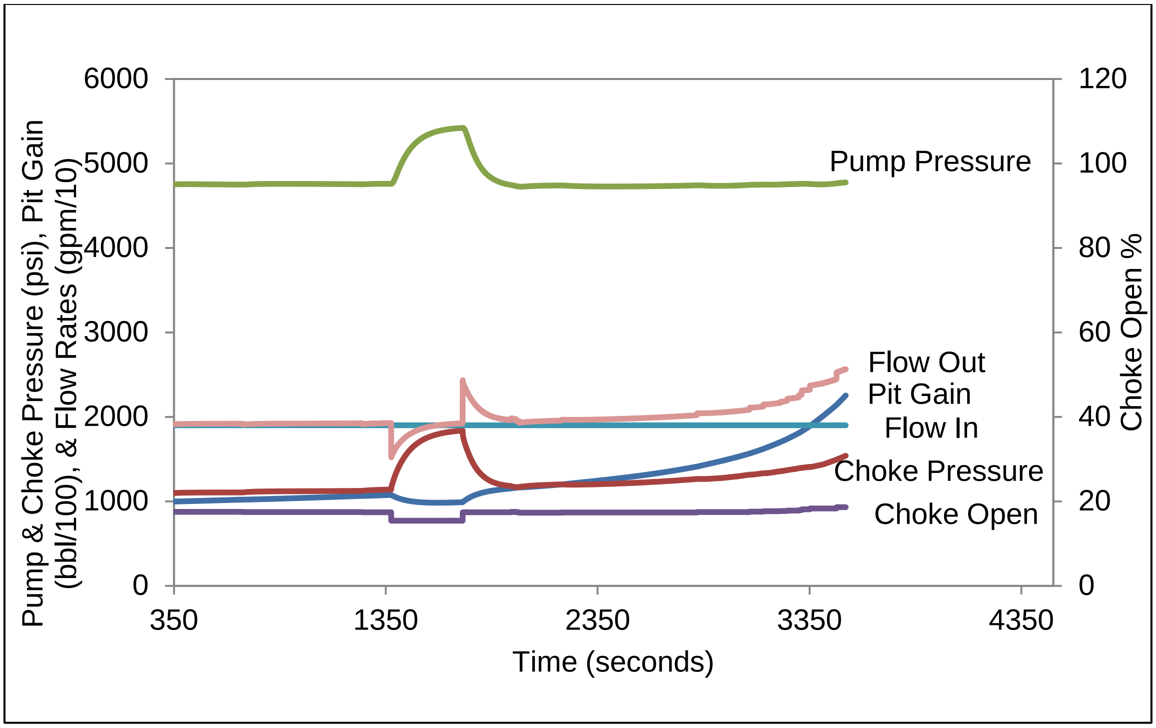

Figure 29: Key indicators for re-route to alternate choke without further consequences

The implied pit gain plot for this event, Figure 30, simulates the onset of partially plugged choke at a ∆ pit gain of .75 bbl. At this moment, the IPG actual curve makes a stark deviation upward indicating an increase in choke pressure from the blockage. The IPG actual curve next transitions in the downward direction due to a lagged pump pressure increase. The increase in BHP from the choke blockage also causes the gas influx to compress as indicated by the transient progression toward negative pit gain. Next, at 0 bbl of ∆ pit gain, the IPG actual curve depicts a sharp drop in Δ surface pressures due to a drop in choke pressure attributed to the re-routing of flow to the alternate choke. Next, a lagged drop in pump pressure drives the IPG actual curve in the upward direction. Going forward, the alternate choke is used to proceed forward with a constant pump pressure kick circulation. As a result, the IPG actual curves returns to the IPG base case slope indicating that no lost circulation or additional influx was caused by the complication.

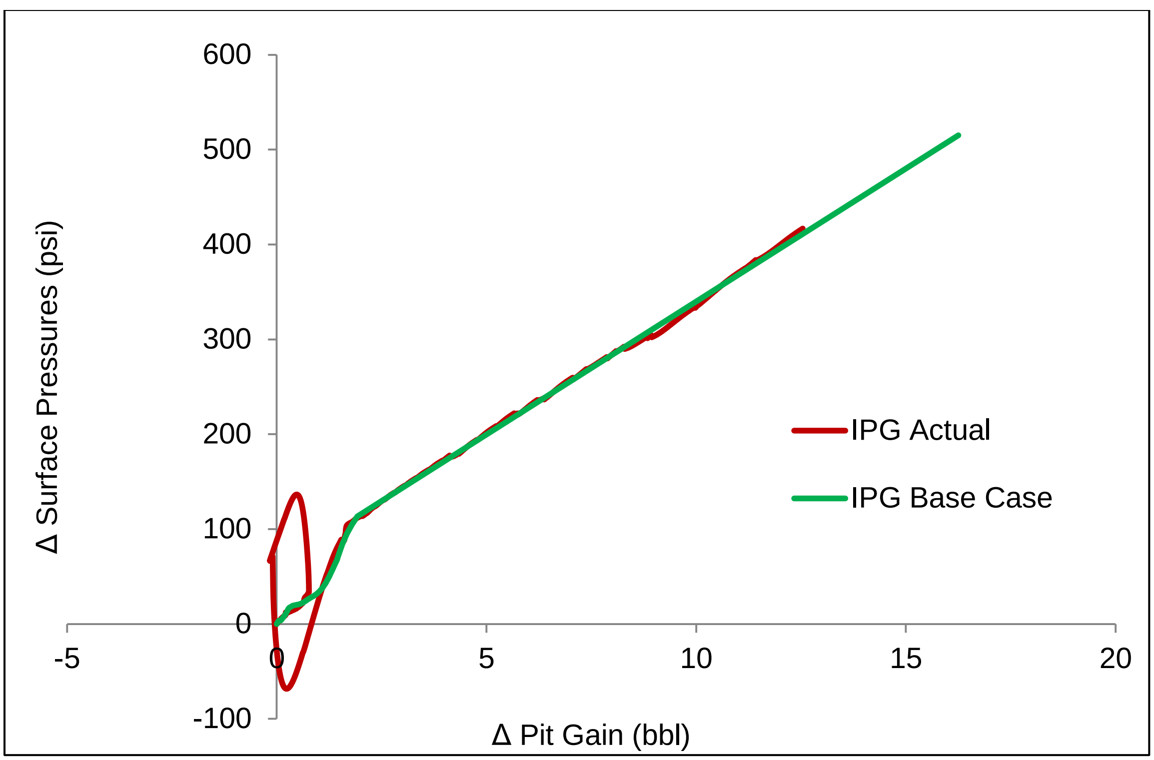

Figure 30: IPG plot for re-route to alternate choke without further consequences

11.1.3 Blockage Cleared, No Additional Complications

A partially plugged choke and subsequent correction of surface pressures by clearing the blockage was simulated for a scenario where no additional influx or lost returns occurred. In order to perform the simulation, the choke opening is first reduced to simulate a blockage. Next the choke is opened to 25.4% in order to simulate an attempt to remove the blockage and recognize a drop in pump pressure. Finally, the choke size is reduced back to 17.4% simulating an effort to resume a constant pump pressure circulation at the target pump pressure value after the blockage is cleared.

The key indicators plot, Figure 31, reflects the onset of a partially plugged choke and subsequent correction of pump pressure at 1350 seconds. The onset of the partially plugged choke caused surface pressures to rise without causing lost circulation. Next, the opening of the choke size to clear the blockage did not drop BHP enough to cause an additional influx. In the end, choke size was adjusted to return pump pressure to the target value.

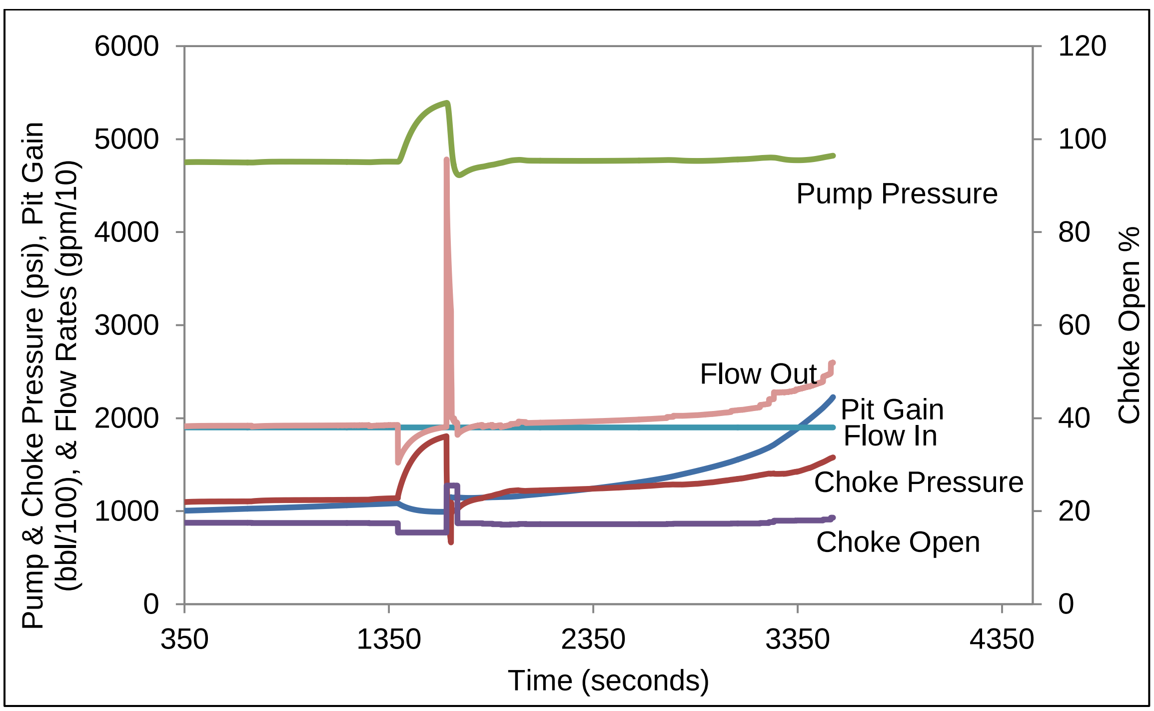

Figure 31: Key indicators plot for a cleared blockage without further consequences

The implied pit gain plot in Figure 32 demonstrates the onset of a partial choke blockage at a Δ pit gain of .75 bbl with an upward deviation in Δsurface pressures led by an increase in choke pressure. Next, the IPG actual curve deviates downward as a lagged pump pressure increase follows the increase in choke pressure. At roughly 0 bbl of Δ pit gain, the IPG actual curve moves starkly downward as choke size is opened to 25.4% in order to let the blockage pass. The wider flow geometry causes a significant drop and upward correction in Δ surface pressures as an immediate decrease in choke pressure is offset by lagged reduction in pump pressure. During this period, the gas influx expands rapidly due to the decrease in BHP. Now that the blockage is cleared, the choke opening is reduced back to its original size of 17.4% to obtain the target pump pressure and proceed with a constant pump pressure circulation. At this point, the IPG actual slope returns to the IPG base case slope indicating that the remainder of kick circulation is not subject to lost circulation or additional influx.

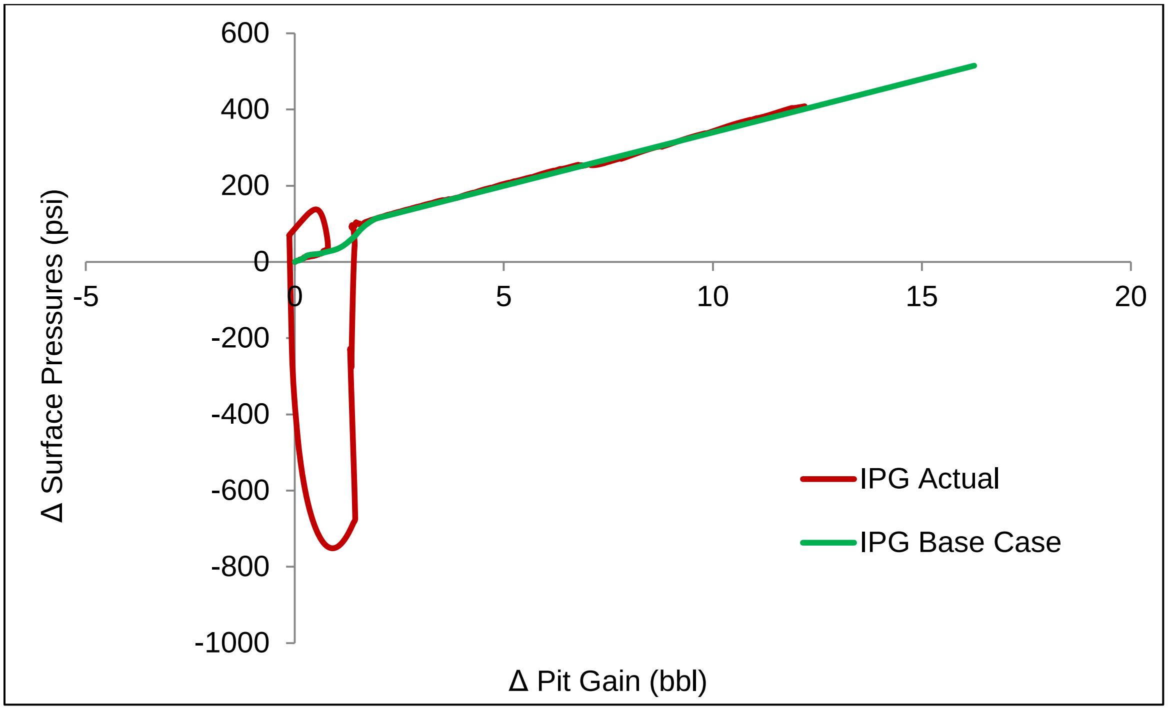

Figure 32: Implied pit gain plot for a cleared blockage without further consequences

11.1.4 No Remediation, Lost Circulation

A partially plugged choke was simulated by incrementally reducing choke size. This action causes wellbore pressure to increase driving both gas compression and lost circulation. Following the occurrence of the partially plugged choke, choke size was left constant to replicate a scenario where no remediation is performed. As a result, the influx was circulated upward while simultaneously losing returns.

The key indicators plot, Figure 33 demonstrates the occurrence of the partially plugged choke at 2030 seconds. During this period, the increased flow restriction causes choke pressures to increase until lost circulation was caused. As a result, both flow out and pit gain showed an immediate decrease. However, as the influx was circulated above the weak zone choke pressure increased to offset the loss in hydrostatic pressure above the weak zone. Choke pressure also increased as gas neared the surface to account for the increased flow rate through a fixed choke opening due to rapid gas expansion.

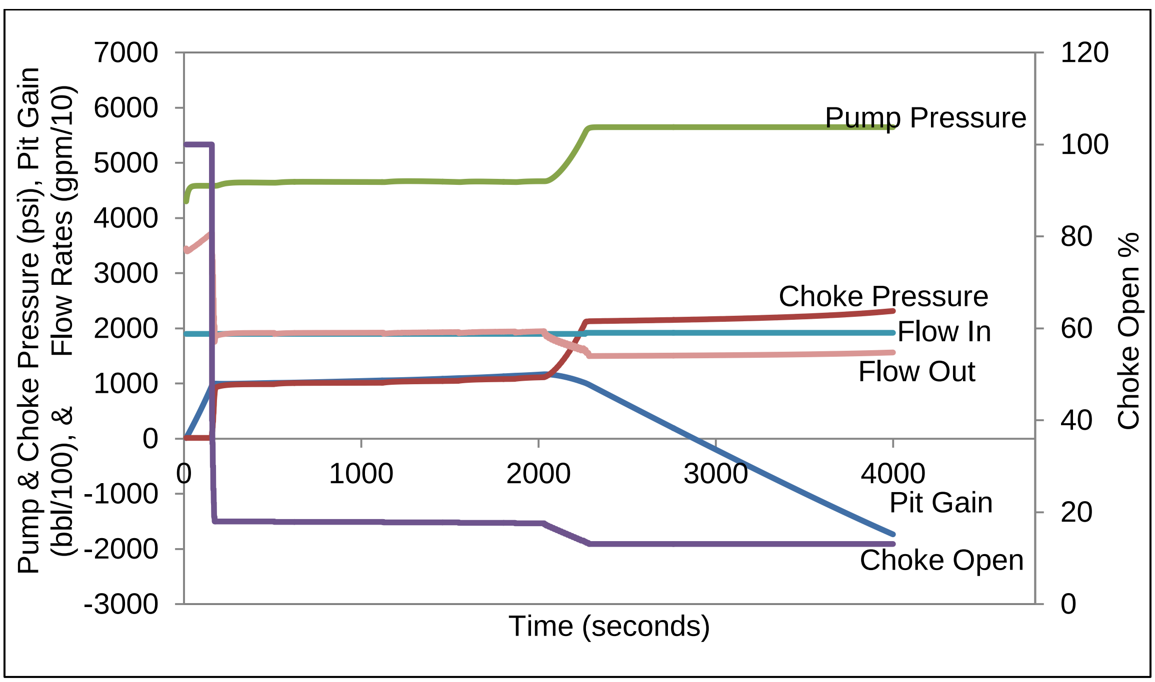

Figure 33: Key indicators plot for a choke plugging with no remediation & lost circulation

The IPG actual plot, Figure 34 depicts the onset of a partially plugged choke by an upward deviation of ∆ surface pressures at 2 bbl of ∆ pit gain driven primarily by an increase in choke pressure. A lagging pump pressure increase associated with the change in choke pressure causes the ∆ surface pressures to experience a correction and begin to move downward. Before increasing by the same magnitude as the increase in choke pressure, pump pressure stabilized due to wellbore pressure exceeding fracture pressure. During this period ∆ pit gain reflects a compression of the gas influx in the annulus and finally, lost returns due to excessive choke pressure generated from the choke size restriction. Following the occurrence of a partially plugged choke, wellbore pressure remained high enough to continuously lose returns as evidenced by consistent reduction in ∆ pit gain. The growth in ∆ surface pressures during this time is the result of a rapid gas expansion causing flow out to increase through a fixed choke size.

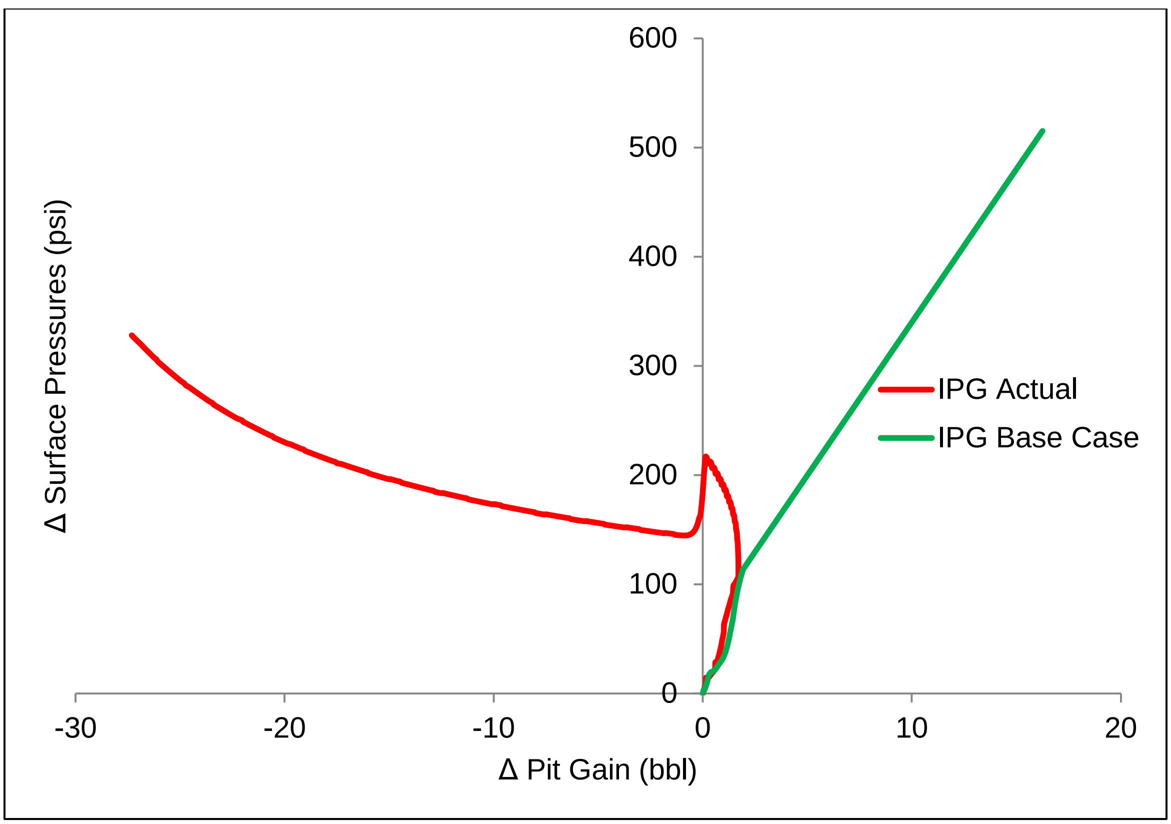

Figure 34: IPG plot for a for a choke plugging with no remediation & lost circulation

11.1.5 Lost Circulation and Re-route to Alternate Choke

A partially plugged choke that causes lost circulation in combination with a re-routing of flow through an alternate choke is simulated. To simulate this event, choke size is reduced from 17.4% to 10.4% to simulate a blockage in the choke and an increase in wellbore pressure that causes lost circulation. Following the increase in pump pressure, the choke size in the simulator is returned to 17.4% to symbolize the diversion of flow to a fully functional choke system.

The key indicators plot for this scenario, Figure 35, represents the onset of a partially plugged choke that was followed by a re-routing of flow to an alternate choke from 1000 to 1850 seconds. As with the previous lost circulation charts, the significant drop in choke size causes a sharp rise in choke pressure with a lagging increase in pump pressure. During this time, wellbore pressure is increased high enough to compress the influx and cause lost returns as depicted by a continuous drop in flow out and pit gain.

At 1450 seconds, the re-routing of flow to the alternate choke is simulated by returning choke size to the original value as evidenced by a significant and transient drop in choke pressure. In the near term, this action results in a relatively stable pump pressure and BHP apparently due to the increased ECD attributed to flow back from the fractured formation (breathing) and rapid gas expansion. Throughout the period of flow back, BHP grows slightly as flow is increased through a fixed choke size. However, once wellbore breathing tapers, BHP begins to drop significantly. At first the behavior is evidenced by a rapid, transient drop in choke pressure and a modest drop in pump pressure. Afterward, pump pressure falls drastically with BHP until stabilizing at the target pump pressure. Finally, pump pressure is held constant at the target pump pressure while choke pressure begins increasing to offset gas expansion as expected in CBHP kick circulation.

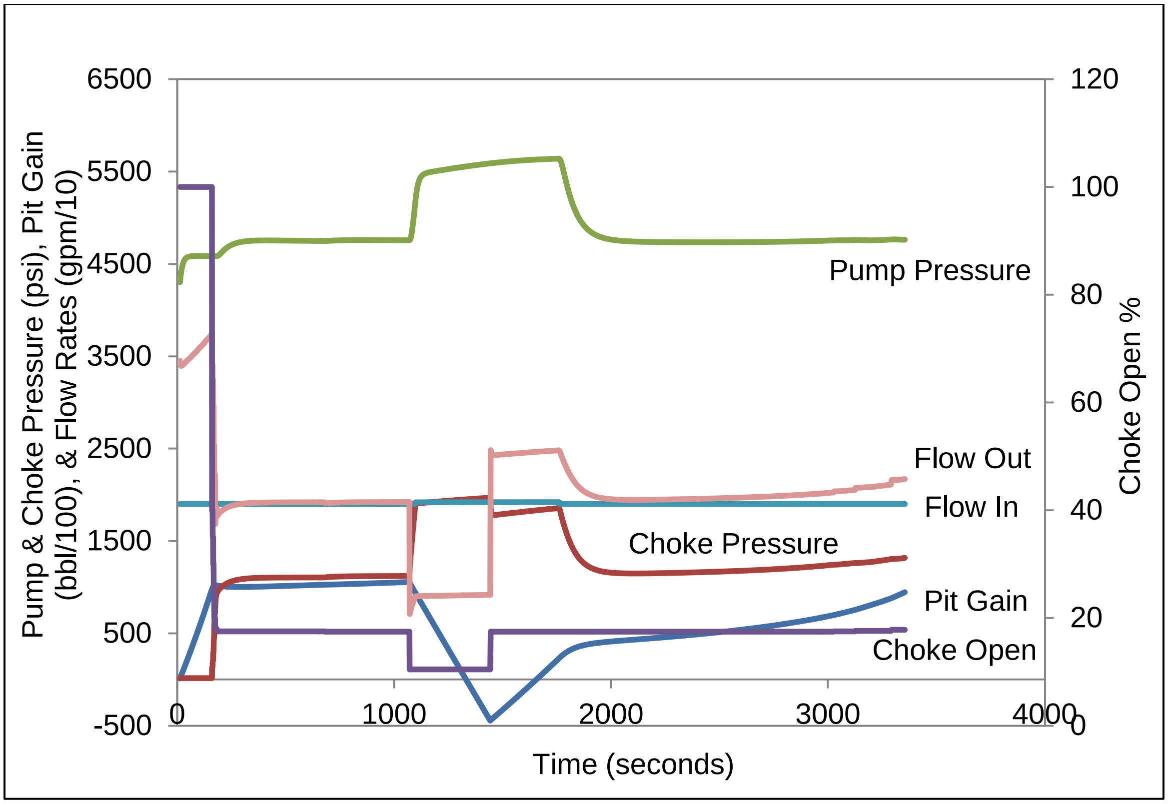

Figure 35: Key indicators plot for re-route to manual choke with lost circulation

The implied pit gain plot for this event, Figure 36, depicts the onset of a partial choke blockage at .75 bbl of Δ pit gain. As seen in previous simulations with lost circulation, the IPG actual curve rises due to an increase in choke pressure, drops briefly due to a lagged increase in pump pressure, and proceeds toward a negative Δ pit gain with a relatively flat slope due to lost circulation. Lost circulation occurs until a Δ pit gain of -14.5 bbl at which point the flow is re-routed causing a drop in Δ surface pressures that is led by a drop in choke pressure. Following this action, Δ surface pressures increase modestly due to the increased flow rate through a fixed choke size from wellbore breathing and gas expansion. Once wellbore breathing subsides at -7.5 bbl of Δ pit gain, Δ surface pressures experience a transient decrease due to the reduction in flow rate causing an aggressive drop in choke pressure and mild drop in both pump pressure and BHP. Following this brief behavior, Δ surface pressures increase with modest reduction in choke pressure and a drastic drop in both pump pressure and BHP until stabilizing at the pump pressure target value. At this point, a successful, CBHP kick circulation is continued in an intact wellbore as evidenced by the return of the IPG actual slope to IPG base case slope.

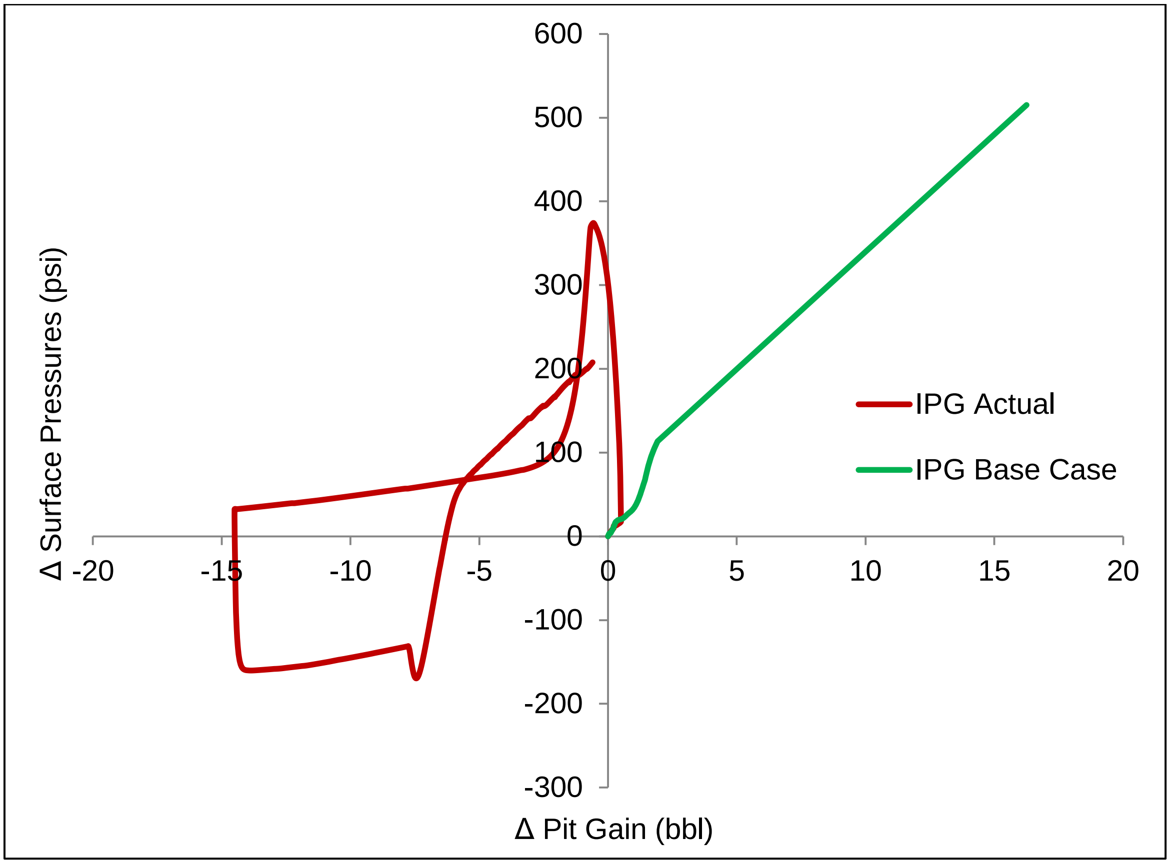

Figure 36: IPG plot for re-route to manual choke with lost circulation

11.1.6 Blockage Cleared, Lost Circulation

In this scenario, a partially plugged choke resulted in lost returns until the blockage was cleared with an increase in choke size. Following this action, choke size was reduced back to its original value in order to resume a constant pump pressure kick circulation at the originally intended target pump pressure through the same choke. In both this scenario and the re-routing of flow in Section 11.1.5, the restriction in flow due to the blockage is actively alleviated by providing a less restricted flow path for the circulation of drilling fluid out of the annulus. In the case of the cleared blockage, this effort was simulated with an opening of choke size from 10.4% to 25.4%. Likewise, in the re-routing of flow, choke sized was increased from 10.4% to 17.4%. A key difference between these scenarios is that the effort to clear the blockage from the choke is followed by a reduction in choke size back to 17.4% to return to the target pump pressure as shown in Figure 37. The overall profile of the IPG plot in Figure 38 does not differ significantly from IPG plot in Figure 36 except for the Δ surface pressures being more negative when attempting to clear the blockage. Furthermore both cases result in a return of the IPG actual slope to the base case slope indicating an intact wellbore.

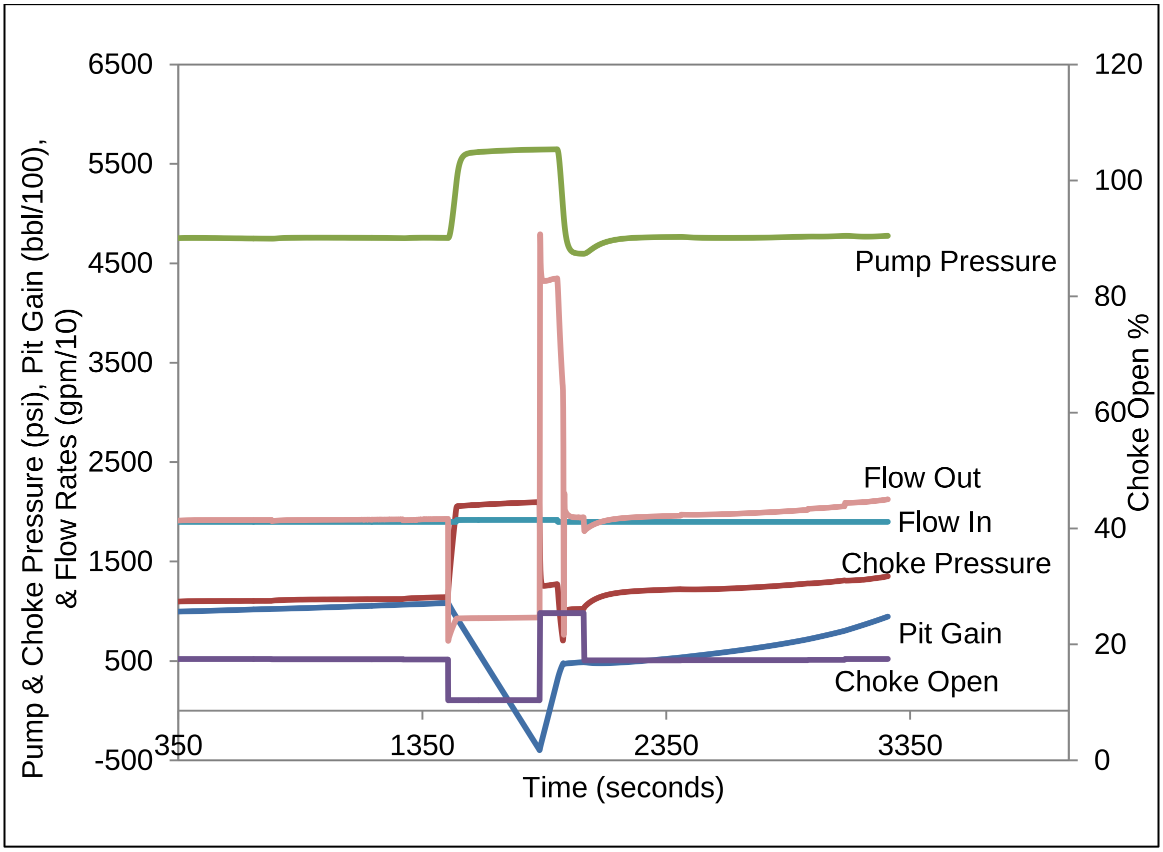

Figure 37: Key indicators plot for a cleared blockage with lost circulation

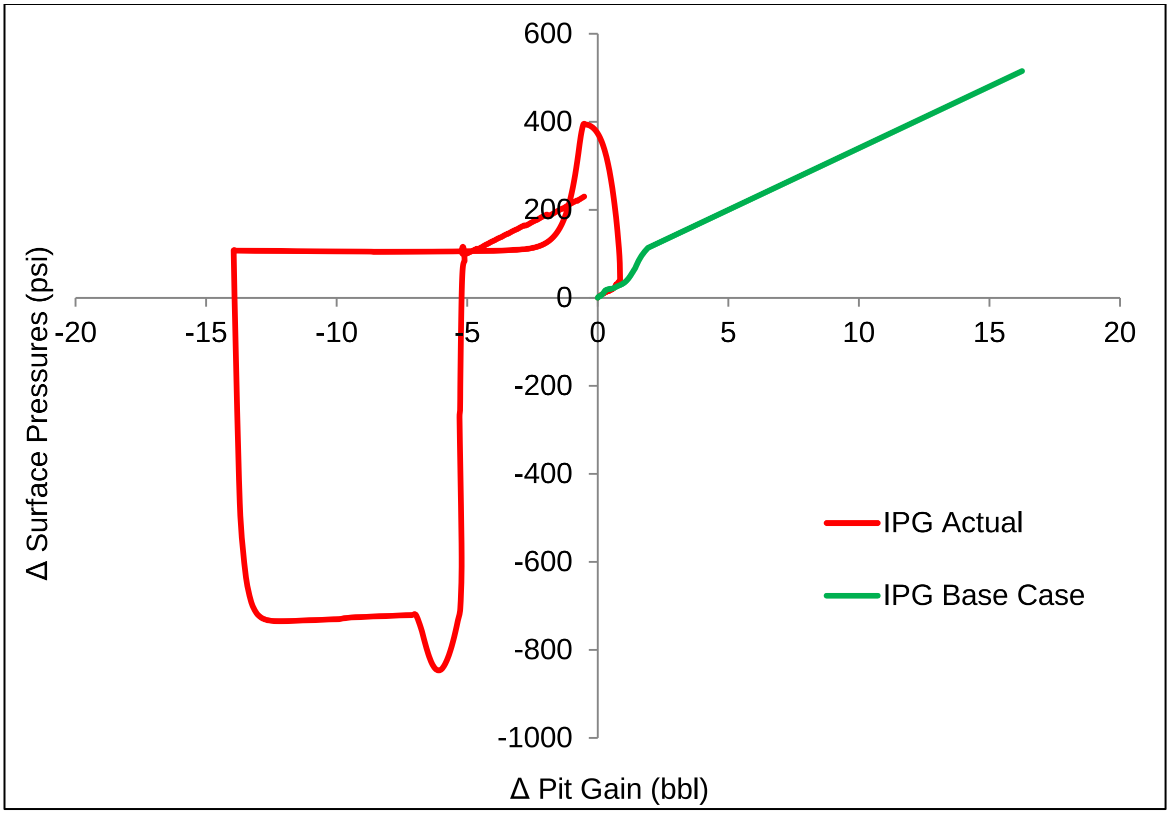

Figure 38: IPG plot for a cleared blockage with lost circulation

11.1.7 Blockage Cleared, Additional Influx

The key indicators plot, Figure 39, demonstrates the onset of a partial choke blockage at 1750 seconds as evidenced by the increase in pump and choke pressure in combination with a small drop in pit gain. In this scenario, the choke size blockage did not cause wellbore pressure to increase high enough to cause lost circulation. However, an additional influx did occur for a brief while as the choke was opened to 100% in order to allow the blockage to pass as evidenced by the sharp increase in pit gain, flow out, and influx flow. During this time, choke pressure was edited to remain constant at atmospheric pressure because of sporadic simulation results yielding unrealistic values. On the other hand, pump pressure and BHP decreased due to lost hydrostatic pressure and the reduction in back pressure from the choke. As with the past simulations, the choke opening was ultimately returned to its pre-complication size in order to regain the target pump pressure and resume kick a CBHP circulation.

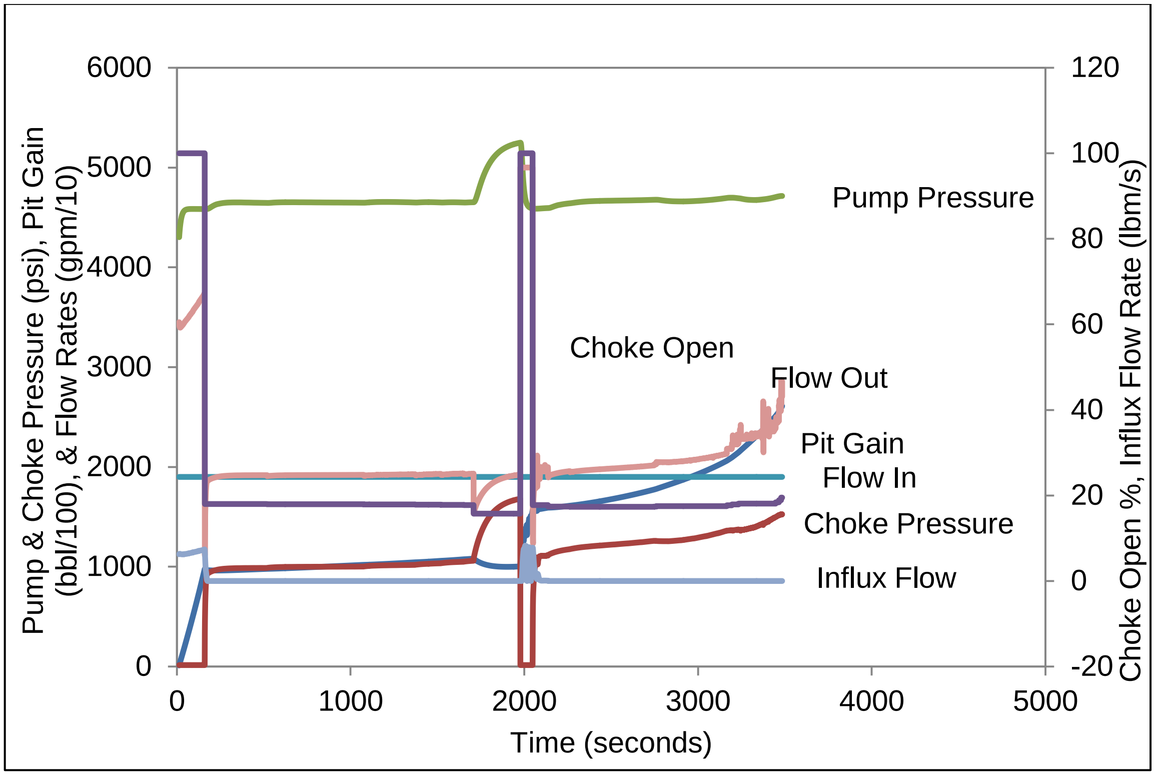

Figure 39: Key indicators plot for a cleared blockage with a temporary additional influx

The implied pit gain plot, Figure 40 demonstrates a partially blocked choke followed by a correction that causes a brief additional influx. The behavior of the IPG actual curve following the onset of the blockage was attributed to gas compressibility and not lost circulation due to the fact that the progression toward negative delta pit gain did not occur continuously or result in a relatively horizontal IPG slope. Instead, the IPG actual curve was deviating downward representing an increase in BHP as pump pressure increased in a lagged fashion to the abrupt change in choke pressure. At .25 bbl of ∆ pit gain, the choke size opened to 100% to allow the blockage to pass as evidenced by the sharp drop in ∆ surface pressures. Since there was no lost circulation, there was no effect of wellbore breathing. Instead, the IPG actual plot begins to deviate upward in a more gradual fashion than in Section 11.1.3 due to a significant drop in pump pressure coupled with a loss in hydrostatic pressure from an additional influx and gas expansion. At 6 bbl of ∆ pit gain, choke size is reduced once more to 17.4% in order to regain the target pump pressure. The choke reduction also increases BHP enough to stop the additional influx. Following this action, the IPG actual curve returns to the IPG base slope indicating a constant pump pressure circulation without the consequences of lost circulation or a continuation of the additional influx.

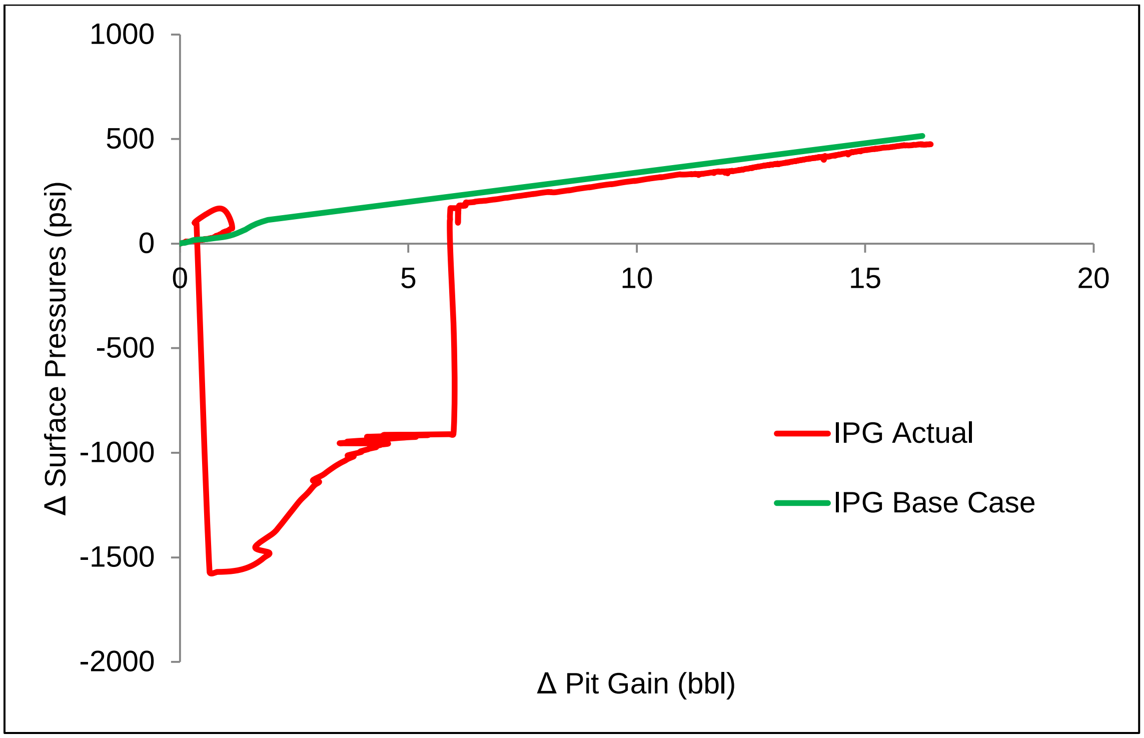

Figure 40: IPG plot for a cleared blockage with a temporary, additional influx

11.1.8 Blockage Cleared, Lost Circulation & Additional Influx

A partially plugged choke scenario was simulated in which both lost circulation and an additional influx occurred before a constant pump pressure kick circulation was resumed as evidenced in Figure 41and Figure 42. This scenario has the general lost circulation and wellbore breathing behaviors discussed in Section 11.1.6 combined with the behaviors of a brief period of additional influx discussed in Section 11.1.7.

Figure 42 demonstrates lost circulation with stabilization of Δ surface pressures and a decrease in Δ pit gain from 1 bbl to -11 bbl. At -11bbl choke size opened to clear the obstruction marked a drastic drop in Δ surface pressures. Following this event, rapid gas expansion and wellbore breathing are evidenced with relatively stabilized Δ surface pressure and increase in pit gain from -11bbl to -3 bbl. At -3bbl, wellbore breathing subsides and onset of an additional influx is indicated by a relatively gradual increase in Δ surface pressures with a rapid increase in Δ pit gain. The additional gain is stopped when choke size is reduced to regain the target pump pressure at 2.5 bbl. The return of the IPG actual slope to the IPG base case slope indicates a CBHP kick circulation in an intact well without any further influx.

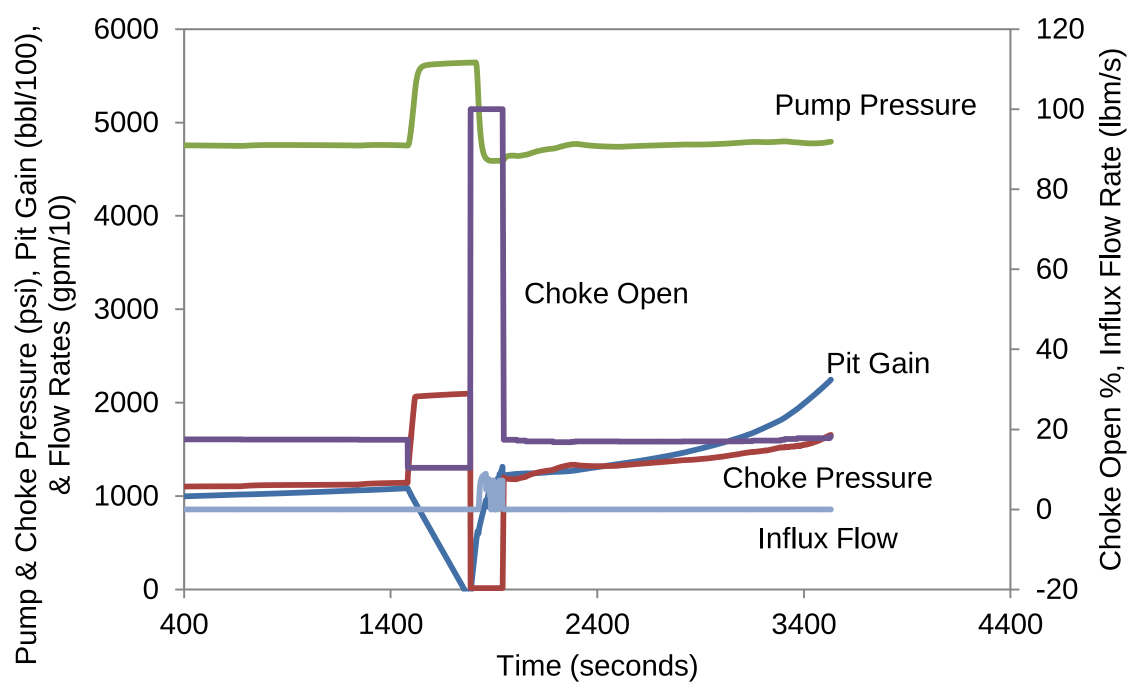

Figure 41: Key indicators plot for a cleared blockage with lost circulation & another influx

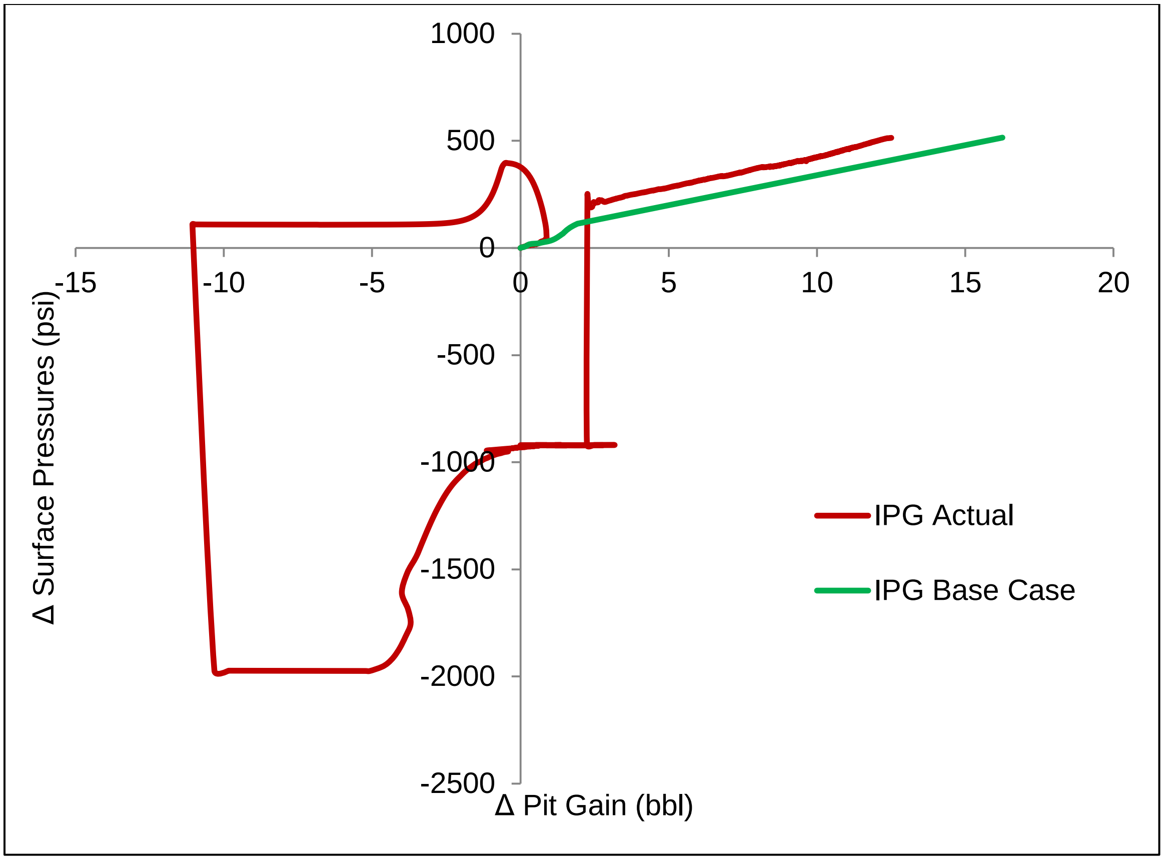

Figure 42: IPG plot for a cleared blockage with lost circulation and additional influx

11.2 Choke Washout or RCD Leak

A choke washout is modeled by subsequent increases in choke size opening over time in order to reflect a leak that no longer permits the choke system to restrict flow beyond a certain limit. Following the occurrence of a choke washout, an operator or automated system no longer has the capacity to adjust choke pressure to control pump pressure for the duration of a kick circulation. Additionally, the inability of the choke system to restrict flow by a desired amount can cause wellbore pressure to fall which may or may not induce an additional influx.

The simulation may also be utilized to analyze an RCD leak that becomes worst over time. Attempts to restrict flow with the choke system in this event are assumed to divert more flow through the RCD. With this in mind, an RCD leak will be modeled with subsequent increases in choke size opening that represent the limitations of the wellbore to restrict flow during this complication. Going forward, a choke washout and RCD leak will be used synonymously.

11.2.1 No Additional Influx

A choke washout that did not result in the initiation of an additional influx was simulated by increasing choke size opening in increments of .5%, .5%, 1%, and 1.25% over a period of 210 seconds. Following this reduction in flow restriction, the choke size was left constant to indicate a continuing leak in the system. Despite the choke system no longer having the ability to appropriately restrict flow, wellbore pressure did not fall low enough to induce an additional influx during the length of the simulation.

The key indicators plot for the choke washout with no additional influx, Figure 43 demonstrates the onset of the washout at 1550 seconds. At this moment in time, the choke size opening was gradually increased by a total of 3.25% over a range of 210 seconds. Throughout this period, choke pressure began to fall. Additionally, the pit gain increased due to expansion of the gas influx from the reduction in wellbore pressure. Each choke size adjustment also caused a short spike upward in the flow out curve. This behavior supports the idea that the drop in wellbore pressure permitted the gas influx to expand rapidly leading to the increase in pit gain. However, the transience of the spike also suggested that the behavior of flow out was not dominated by an underbalance. Otherwise, flow out would have continued to increase. Finally, following onset of the washout, a drop in pump pressure lagged the drop in choke pressure causing a drop in BHP. However, as gas near the surface, rapid expansion caused flow through a fixed choke size to increase resulting in an increase in choke pressure, pump pressure and BHP. However, pump pressure would not grow as fast as choke pressure due to the loss in hydrostatic pressure in the annulus. If the leak continued to worsen, one would expect the wellbore to divert more flow through the leak and prevent BHP from increasing.

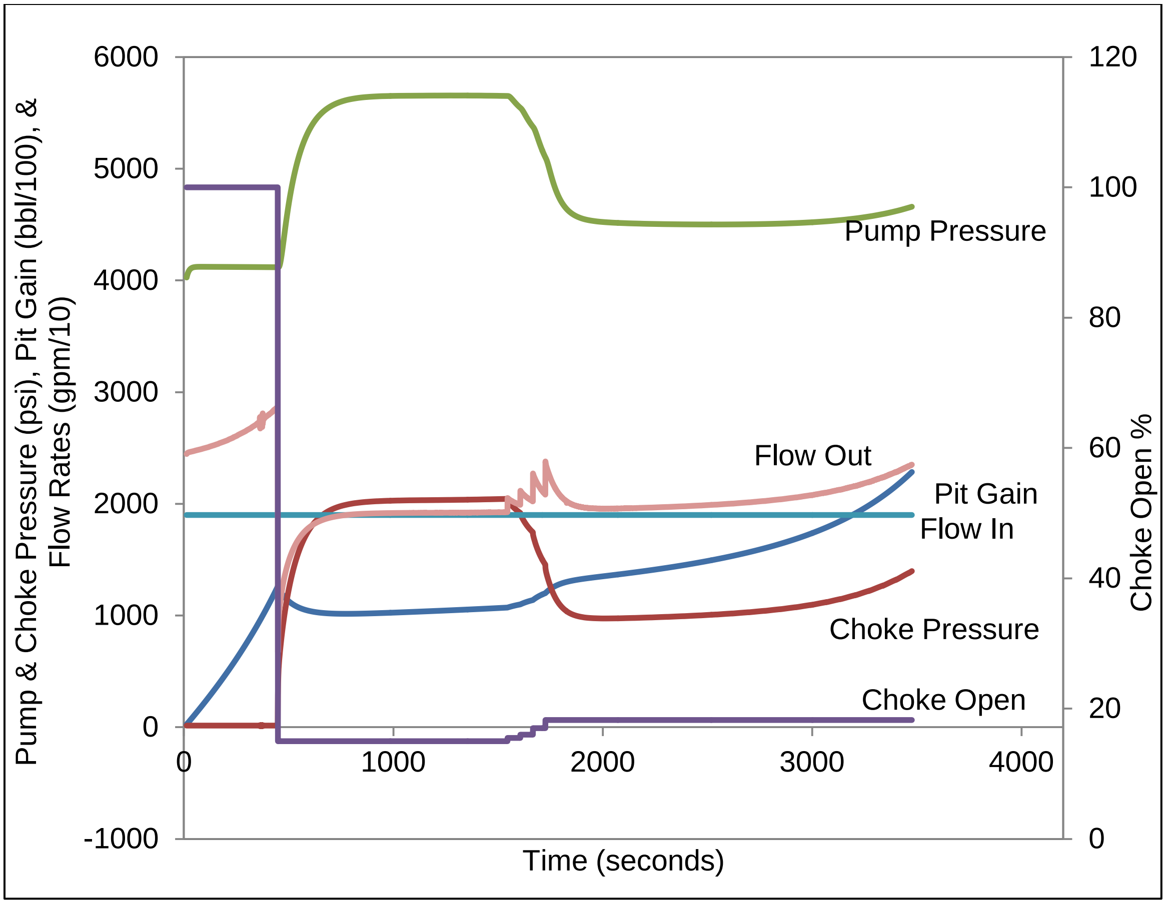

Figure 43: Key indicators for choke washout/RCD Leak with no additional influx

The IPG actual curve, Figure 44, depicts the onset of the choke washout at a Δ pit gain of .5 bbl. Following this time, four successive drops and recoveries in Δ surface pressures occur. Following the final choke size adjustment, Δ surface pressures recover from a final dip downward as the total drop in choke pressure attributed to the washout is offset by a lagged drop in pump pressure as evidenced between 2.1 and 2.8 bbl. In the period between 2.8 bbl and 4.7 bbl, pump pressure continues to fall slightly while choke pressure resumes increasing. This behavior is attributed to the loss in hydrostatic pressure creating a decrease in BHP. Following 4.7 bbl, choke pressure increases at a greater rate than pump pressure indicating an increase in BHP due to the increased flow rate through a fixed choke size as gas nears the surface. As a result of the mild BHP changes, the slope of the IPG actual curve is slightly steeper than the IPG base case.

However, the two slopes are similar enough to indicate that the consequence of this complication is not significant, thus no additional influx is occurring.

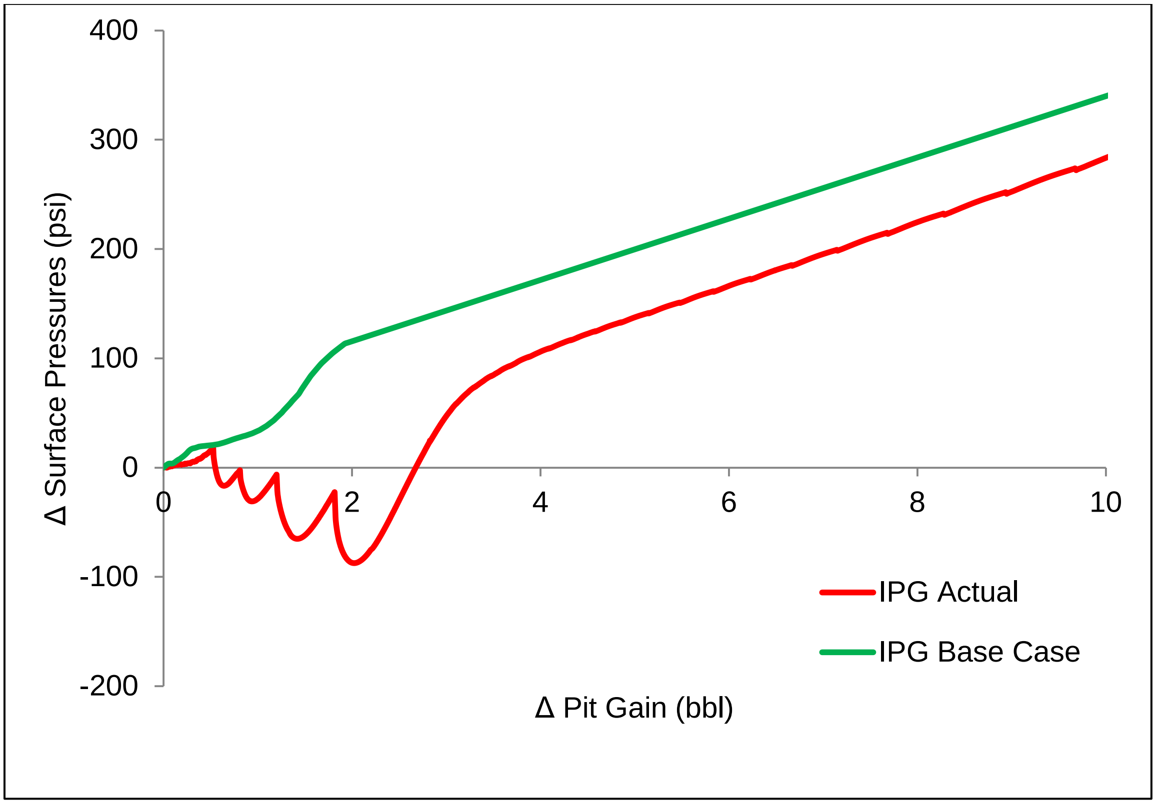

Figure 44: IPG plot for a choke washout/RCD Leak with no additional influx

11.2.2 Additional Influx

A choke washout that resulted in the initiation of an additional influx was simulated by increasing the choke size opening in increments of 1%, 1%, 2%, and 2% over a period of 210 seconds. Following the decrease in flow restriction, the choke size was left constant to indicate the effects of a leak in the system that is left uncorrected. With the choke system no longer having the ability to appropriately restrict flow, wellbore pressure falls below formation pressure and an additional influx was initiated. Going forward, the additional influx cannot be stopped due to the inability of the choke to trap pressure. As a result, the wellbore fills with gas throughout the remainder of the kick circulation.

The key indicators plot, Figure 45 for the simulation of a choke washout with additional an influx demonstrates the onset of the complication at 1250 seconds. At this moment, the choke size is increased by a total of 6% over a period of 250 seconds to simulate the washout. In connection with the last choke size adjustment, BHP fell below formation pressure, and an additional influx was taken as indicated by the significant increase in pit volume and flow out of the wellbore. The inability of the choke system to control pump pressure is also indicated by a drop in pump pressure.

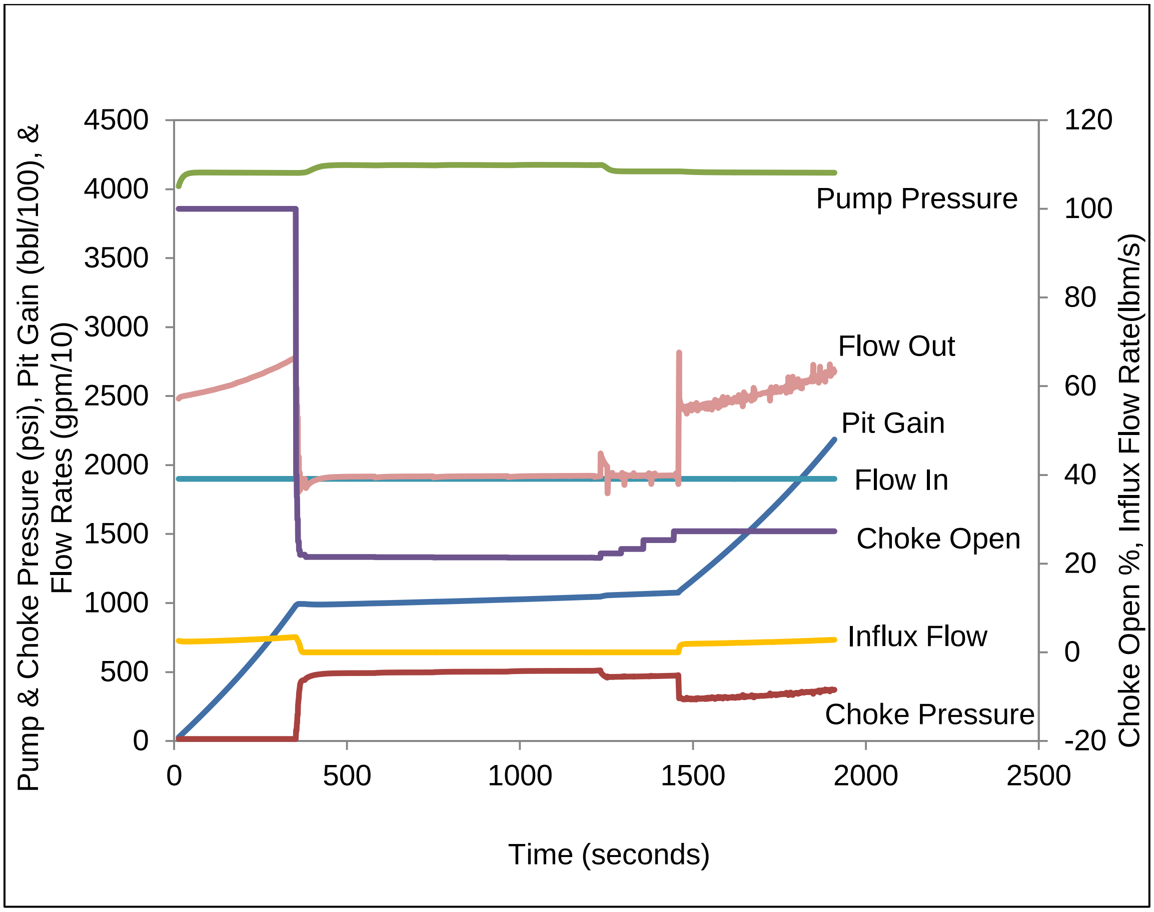

Figure 45: Key indicators for a leaking choke/RCD causing an additional influx

The implied pit gain plot, Figure 46, depicts the onset of a choke washout at a Δ pit gain of .5 bbl. At this point in time, the choke size opening was increased from 21.3% to 22.3%. This 1% increase in choke size opening causes choke pressure and therefore pump pressure to fall by about 45 psi. The short drop and immediate increase in the Δ surface pressures at this moment is attributed to the lag time associated with the pump pressure change. Subsequent choke size reductions were made until the wellbore became underbalanced at a Δ pit gain of 1 bbl. The onset of an additional influx is evidenced by the drop in Δ surface pressures and the relatively shallow slope of the IPG curve while progressing toward positive Δ pit gain. The slope that is more horizontal than expected is representative of Δ surface pressures not increasing enough to offset the loss in hydrostatic pressure from the continued gas influx that is occurring in addition to gas expansion in the wellbore.

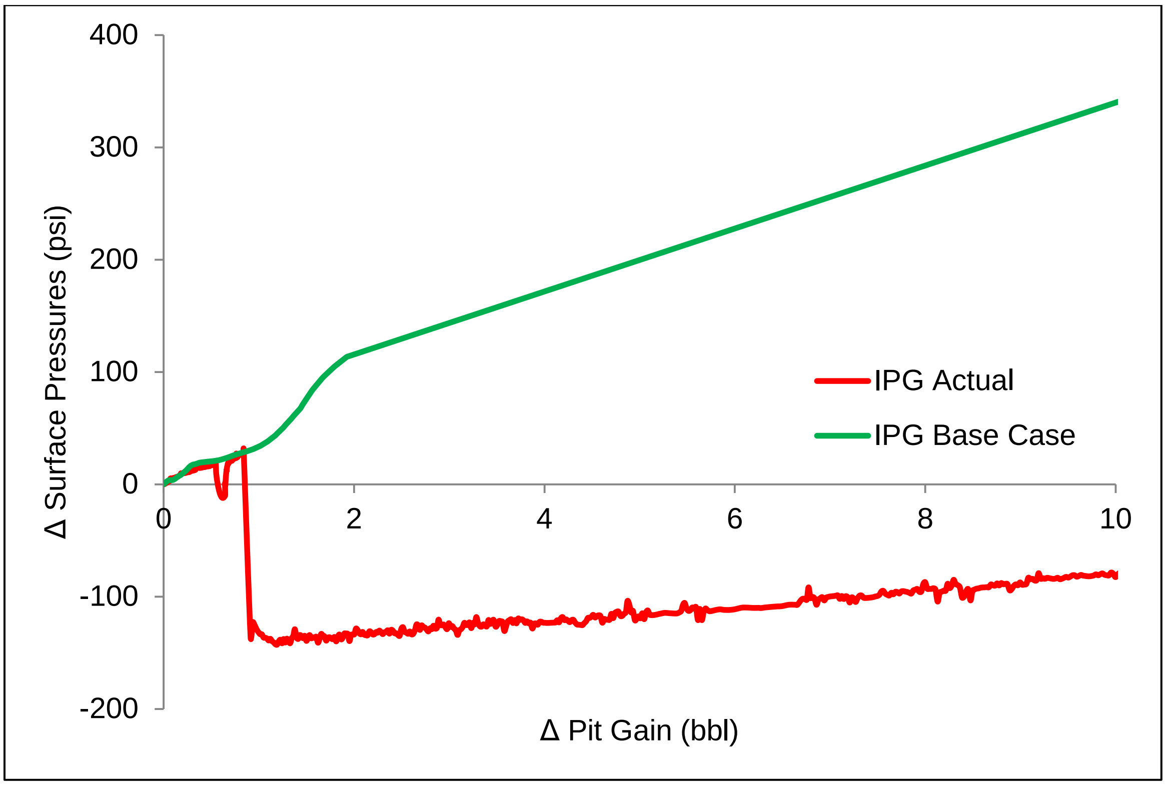

Figure 46: IPG plot for a leaking choke/RCD causing an additional influx

11.3 Passive Loss of Choke Control

A passive loss of choke control is intended to represent an operator or system error in which the application of increased choke pressure to offset lost hydrostatic pressure in the wellbore is no longer applied. In such an event, the influx may have been circulated successfully for a period of time until the choke size is no longer adjusted.

The impacts of a passive loss of choke control are typically a drop in wellbore pressure while the influx is still deep in the wellbore and a slight increase in wellbore pressure as the influx rapidly expands near the surface. The drop in wellbore pressure is attributed to the loss of hydrostatic pressure from gas expansion that is not offset with an increased in choke pressure. The increase in wellbore pressure with gas near the surface is attributed to increased flow through a fixed choke size. Depending on the amount of overbalance held, the effects of the drop in wellbore pressure may or may not cause an additional influx to occur.

11.3.1 No Additional Influx

A passive loss of choke control was simulated by circulating an influx up to 12200' MD and then leaving the choke unattended at a fixed choke size opening of 19.9%. An additional influx was not initiated due to the magnitude of the overbalance in the wellbore prior to the loss of coke control. As the influx neared the surface, rapid gas expansion caused an increase in BHP and pump pressure.

As shown in the key indicators chart,

Figure 47, the impacts of the passive loss of choke control that occurred around 1000 seconds begin to manifest themselves around 1800 seconds. Over that period of 800 seconds, gas expansion causes BHP to fall by 70 psi. When the influx nears the surface, pump pressure and BHP increase 127 psi due to rapid gas expansion. Since an additional influx did not happen, the kick circulation was still able to occur with success despite the complication.

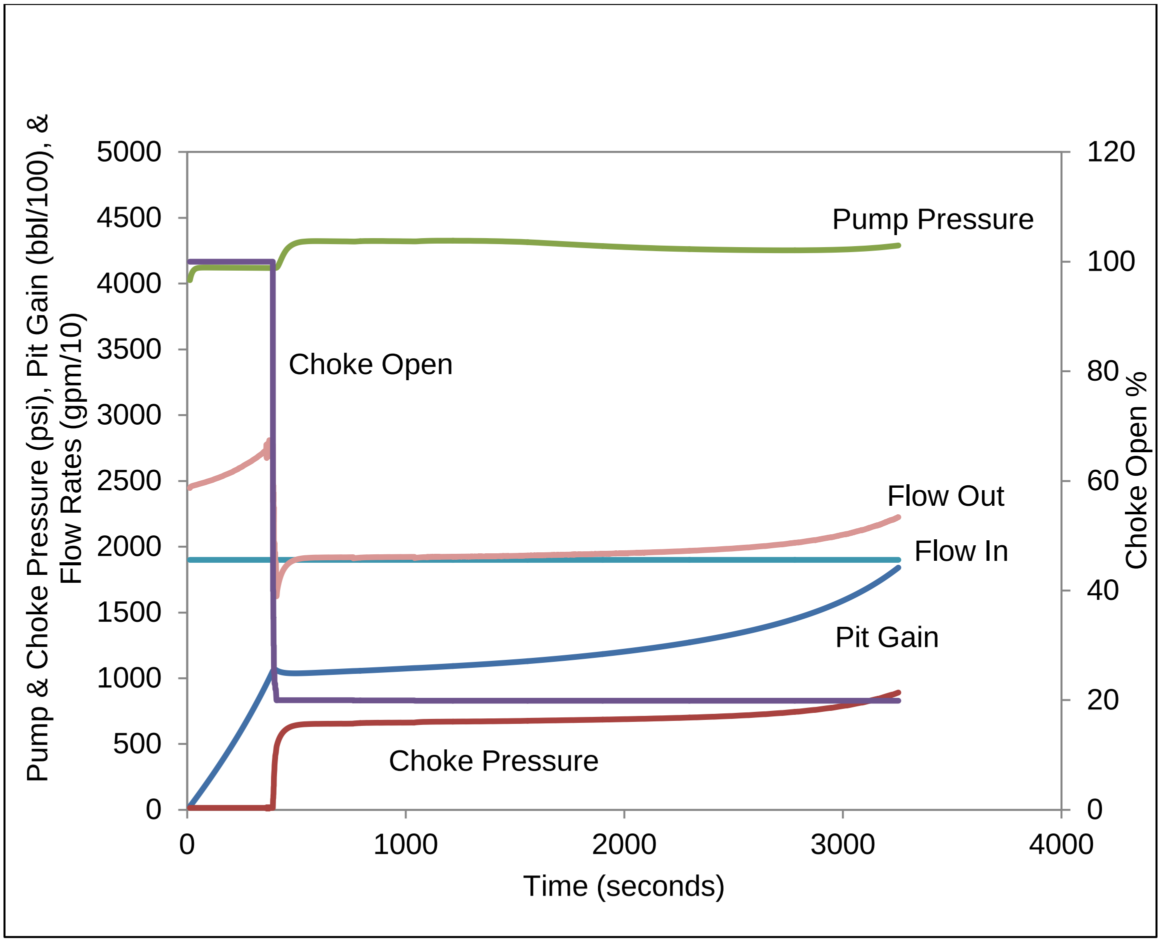

Figure 47: Key indicators plot for a passive loss of choke control with no additional influx

The IPG plot, Figure 48, for the passive loss of choke control depicts a modest deviation between the IPG actual and IPG base case curves at 1.2 bbl of Δ pit gain. Follow this point in time, the IPG actual curve deviates slightly in the downward direction to a drop in BHP from gas expansion and later slightly in the upward direction due to an increase in BHP from increased flow through a fixed choke size. However, despite these behaviors, the slope of the IPG actual case is almost exactly the same as the IPG base case indicating that this complication does not bear the consequences of an additional influx.

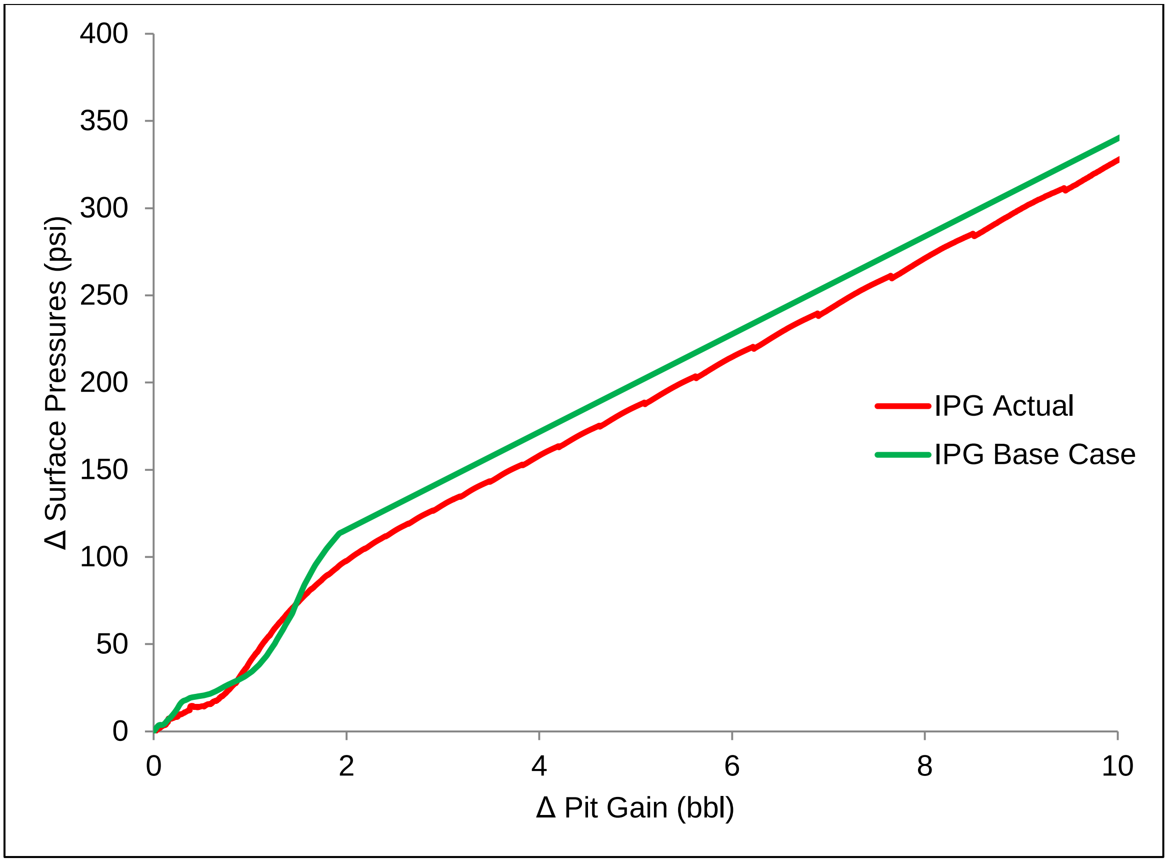

Figure 48: IPG plot for a passive loss of choke control with no additional influx

11.3.2 Additional Influx

A passive loss of choke control was simulated by circulating an influx up to 12400' MD and then leaving the choke unattended at a fixed choke size opening of 21.75%. Over the next 13 minutes, the gas influx expanded without the addition of choke pressure permitting wellbore pressure to fall by 23 psi. As a consequence, bottom-hole pressure fellow below formation pressure causing an additional influx to be initiated. As the first influx neared the surface, rapid gas expansion increased wellbore pressure by a relatively small amount. However, this was not enough to stop the second influx from continuously entering the wellbore.

As shown in the key indicators chart, Figure 49, the impacts of the passive loss of choke control that occurred around 1000 seconds begin to manifest themselves around 1800 seconds when the second influx begins. Over that period of 800 seconds, pump pressure fell and choke pressure slightly increased as gas expansion pushed fluid out of the wellbore at a modestly increasing rate. Around 1800 seconds, the drop in BHP triggered an additional influx as evidenced by the rapid growth in pit gain and flow out. As the wellbore continues to fill with gas, choke pressure and flow out increase due to gas expansion, while pump pressure falls.

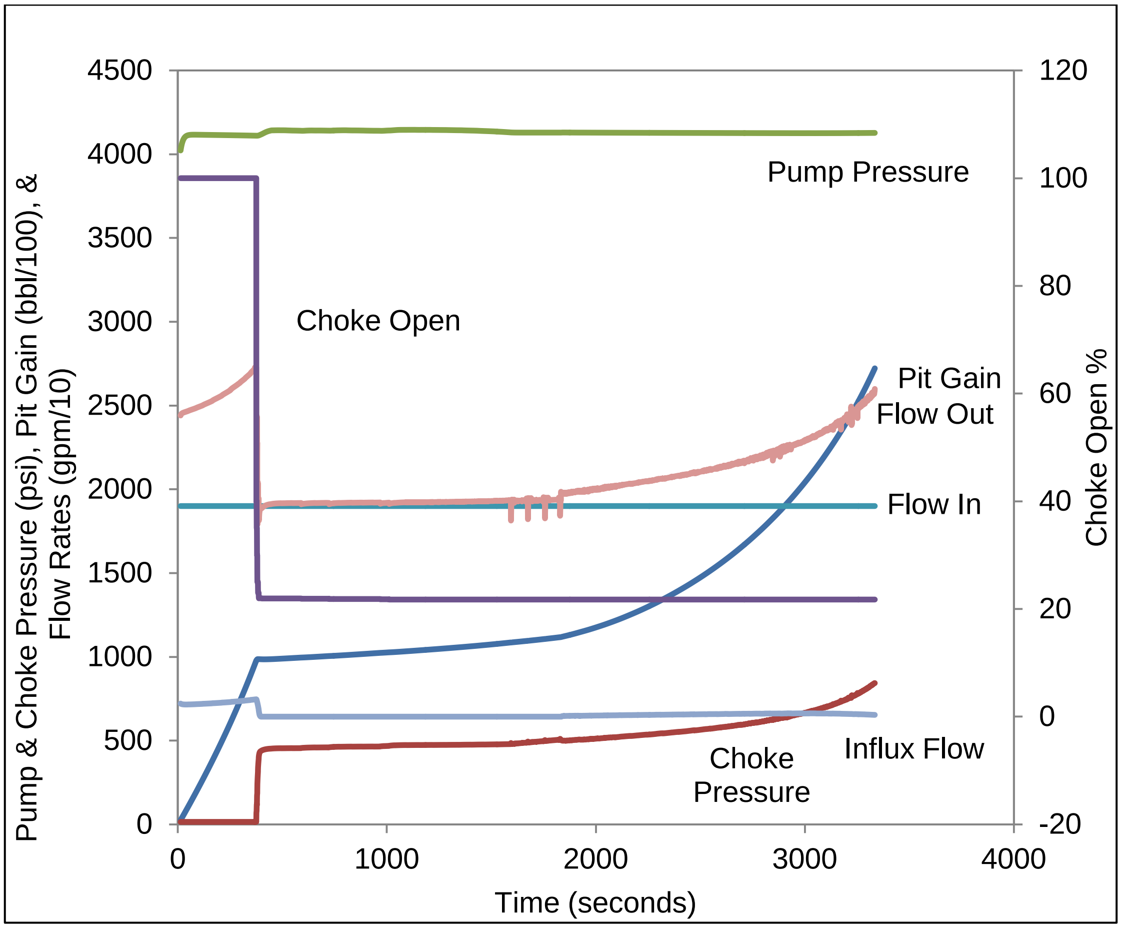

Figure 49: Key indicators plot for a passive loss of choke control causing another influx

The IPG plot, Figure 50, for the passive loss of choke control depicts a clear deviation between the IPG actual and IPG base case curves at 1.2 bbl of ∆ pit gain. At this point in time, the impacts of losing choke control are manifested in the form of a reduced slope in the IPG actual line. This reduced slope reflects the fact that ∆ surface pressures, more specifically choke pressure, is not increasing quickly enough to offset the loss in hydrostatic from the continued influx that is occurring in addition to gas expansion.

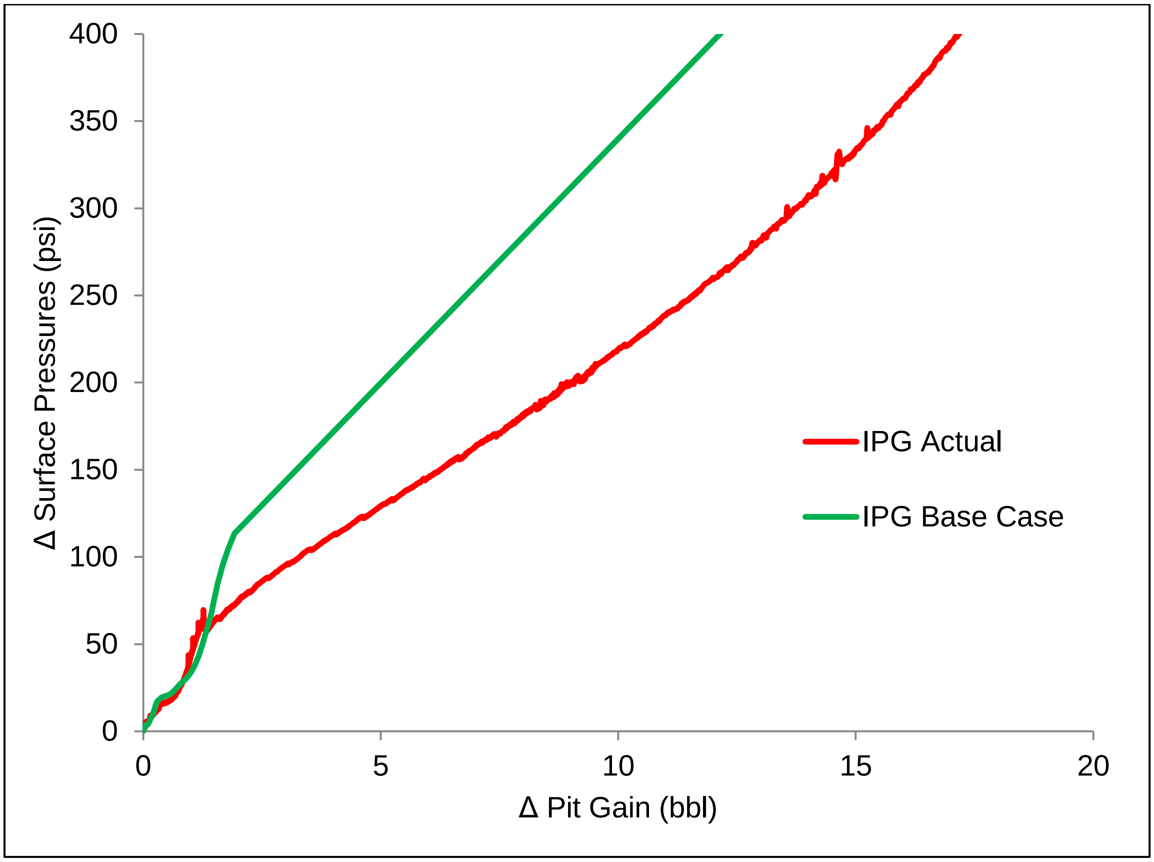

Figure 50: IPG plot for a passive loss of choke control resulting in an additional influx

12 Well X Impending Underground Blowout Simulations

Simulations performed by Das demonstrated that forcing flow rate out equal to flow rate in as the criteria for having stopped an influx may be incorrect and unsuccessful in stopping formation flow when dealing with an impending underground blowout. In this work, an impending underground blowout refer to scenarios where kick tolerance has been exceeded or when the pore pressure gradient in the high pressure zone is higher than the fracture pressure gradient in the weak zone. The latter was a simplification created by Das to overcome software limitations associated with creating a scenario where kick tolerance was exceeded.

In Das' simulations, restricting choke size to force flow out equal to flow in effectively caused an equilibrium between the amount of fluid lost in the wellbore and the amount of fluid being pushed out of the wellbore by gas expansion and the continued influx. As a result, Das demonstrated that forcing flow rates to be equal can mask the simultaneous occurrence of taking an influx and losing returns. Building forward from Das' work, the following simulations will demonstrate how the IPG method can be utilized to determine if an impending underground blowout are occurring in the wellbore. Finally, IPG actual curves will only be compared against IPG base case predictions with a no slip model to simplify the plots.

12.1 Constant Pump Pressure Response

A simulation attempting to maintain constant pump pressure in response to a pore and fracture pressure margin complication was performed as follows. After drilling into a high pressure zone, a 10 bbl influx was taken into the wellbore before subsequent choke size reductions were deployed to force flow rates to be equal. Once this occurred, an attempt was made to hold the existing pump pressure constant for the duration of the kick circulation.

The key indicators plot, Figure 51 depicts the behavior of surface indicators during this response. At 200 seconds, a series of choke size adjustments were performed to force flow rates to be equal. With the flow rates equal, the influx was considered to be stopped. Thus, the choke operator attempted to maintain a constant pump pressure at 230 seconds. However, as the wellbore continued to fill with gas, pump pressure fell, despite successive choke size reductions seen in the period following 230 seconds. During this period, pit gain fell due to lost circulation. Also choke pressure was increased due to the continued influx of gas and gas migration above the weak zone. At 538 seconds, the choke was closed entirely with the mud pumps running and the pump pressure continued to fall. The influx flow rate, which cannot be measured during drilling operations, confirmed that an influx was still occurring.

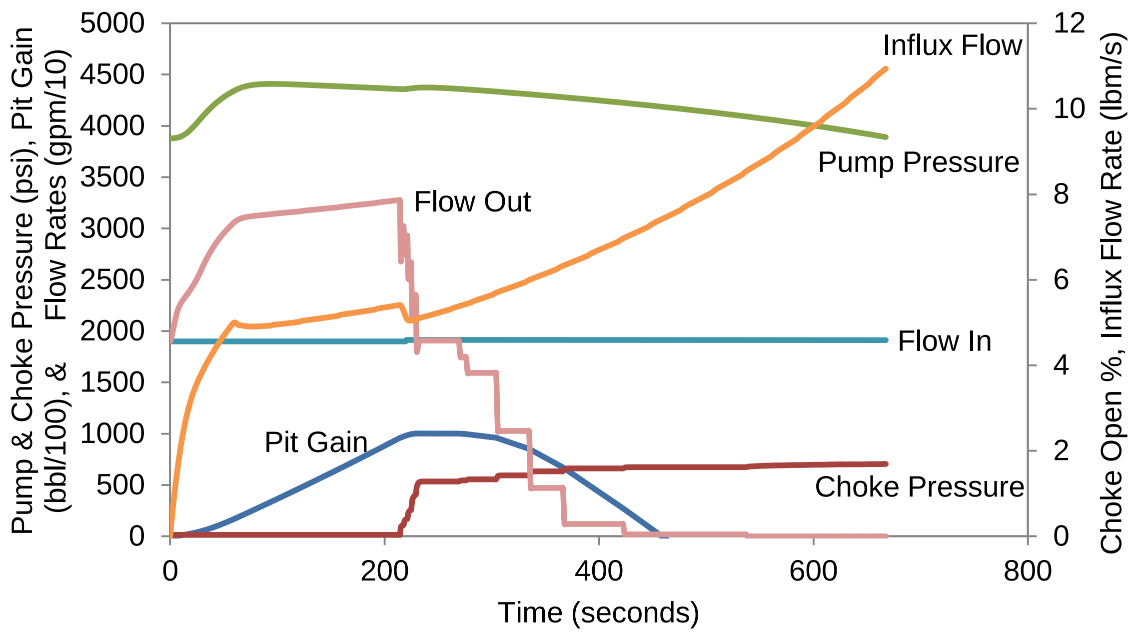

Figure 51: Key indicators plot for an impending underground blowout while trying to maintain a constant pump pressure during circulation

The IPG plot, Figure 52, the IPG actual curve deviates to the left due to the negative ∆ pit gain values attributed to lost circulation. ∆ surface pressures grow rapidly due the increase in choke pressure and decrease in pump pressure that occurs due to simultaneous influx and downhole loss scenario. The increase in choke pressure is attributed to loss in hydrostatic pressure associated with a continued influx and gas migration above the weak zone. The drop in pump pressure is attributed to the reduction in wellbore pressure due to the loss in hydrostatic pressure below the weak zone. The immediate deviation between IPG actual and base case curves suggests that the IPG method may compliment equal flow rates as a confirming indicator that an influx has been stopped. Additionally, the IPG actual curve does not deviate in an abrupt vertical fashion which would indicate an increase in wellbore pressure prior to fracture as may be seen in typical lost circulation complications. The behavior is due to the fact that the formation was already fractured immediately at the onset of the kick circulation.

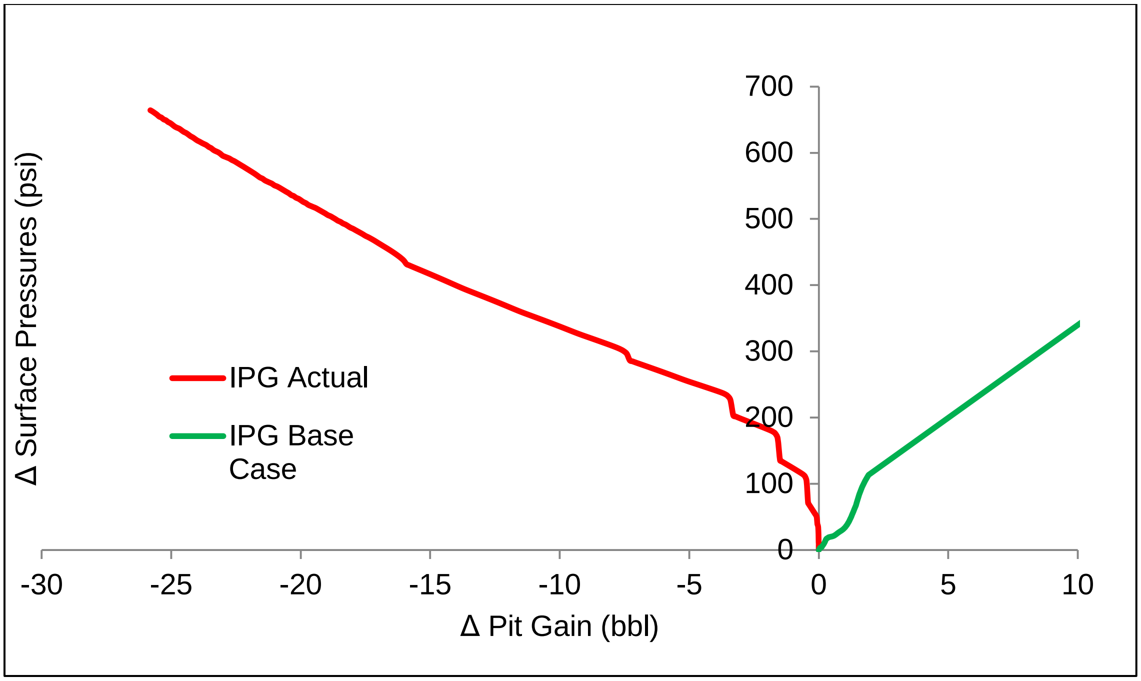

Figure 52: IPG plot for an impending underground blowout while trying to maintain a constant pump pressure during circulation

12.2 Constant Flow Rate Response

A simulation of a constant flow rate response to the same scenario discussed in Section 12.1 was performed. It should be noted that this response is generally inappropriate and not commonly used. The benefits of modeling this response are to emphasize that forcing flow rates equal for an extended period of time does not necessarily stop the flow of formation fluid into the wellbore.

The key indicators chart, Figure **53**, depicts a series of choke size adjustments made in an attempt to stop an influx and force flow rates to be equal for an extended period of time. This response is evidenced by a very small change in pit gain. Furthermore, Choke pressure increases rapidly over time from the continued influx and gas migration above the weak zone. Pump pressure continues to fall along with wellbore pressure due to the loss in hydrostatic pressure below the weak zone.

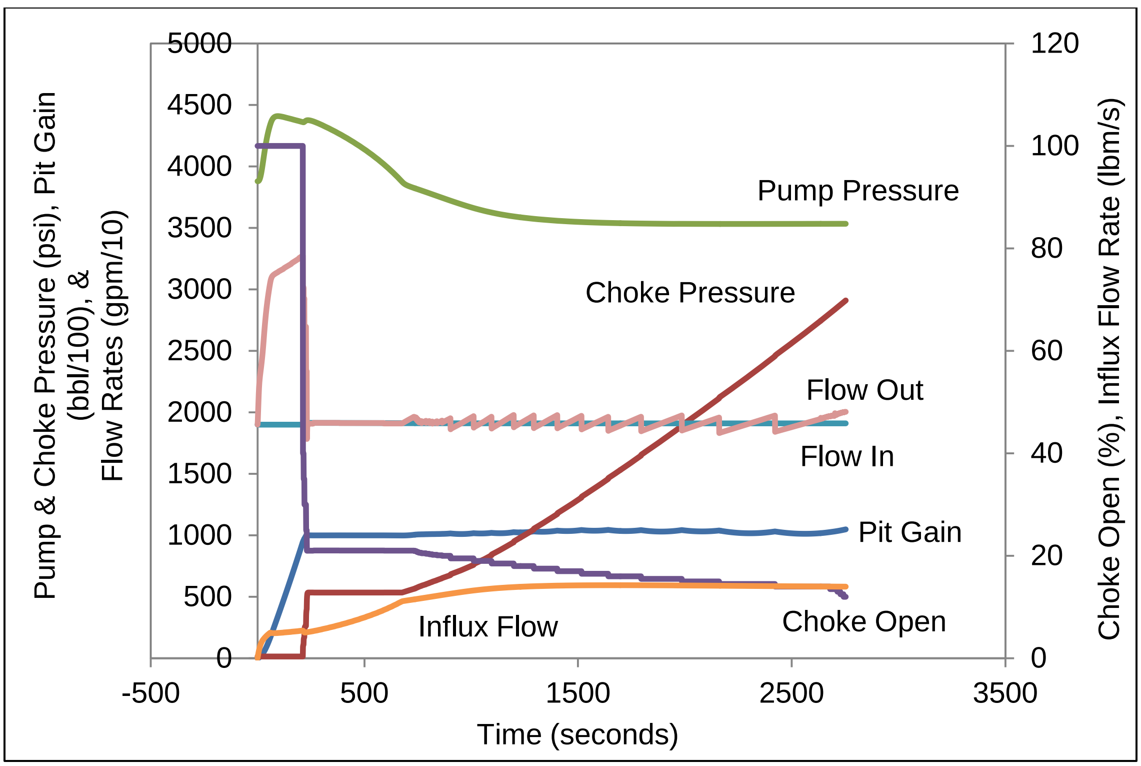

Figure 53: Key indicators plot for an impending underground blowout while trying deploy a constant flow rate response

The IPG Plot, Figure 54, demonstrates an immediate deviation between the IPG actual and IPG base case curves. The Δ surface pressures increase rapidly due the increase in choke pressure and decrease in pump pressure that occurs as result of simultaneous downhole losses and influx. Δ pit gain remains relatively unchanged as maintaining equal flow rates has masked both the lost circulation and continued influx. The unchanged Δ pit gain throughout the scenario is the reason that the IPG actual curve is vertical.

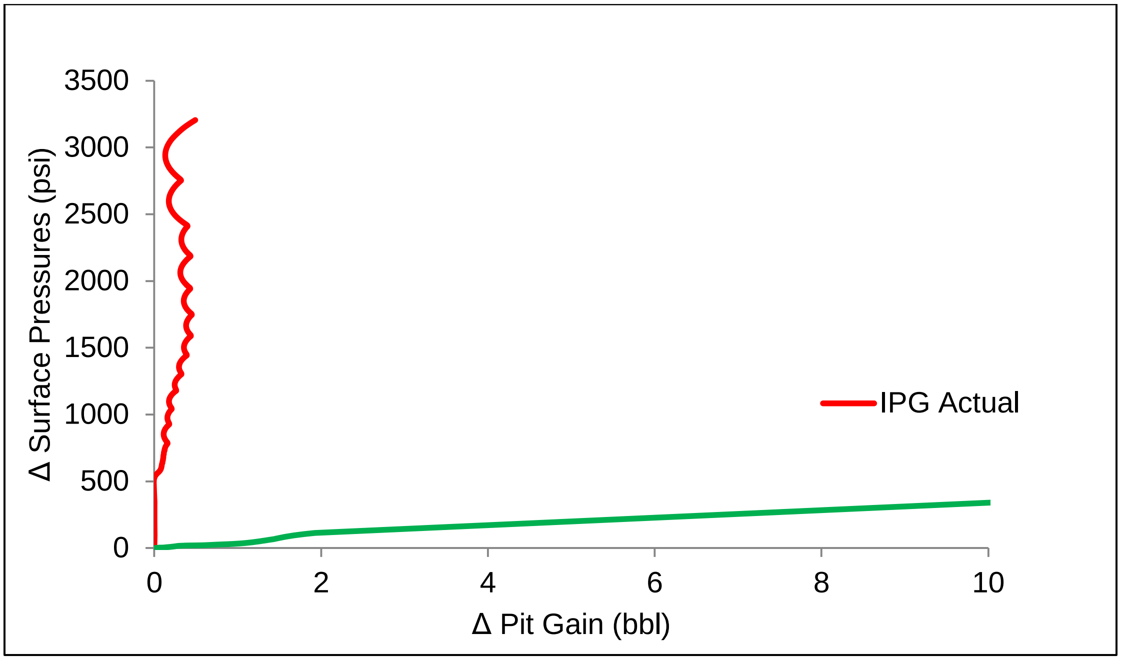

Figure 54: IPG plot for an impending underground blowout while trying to deploy a constant flow rate response

12.3 Influx Size Exceeds Kick Tolerance

A simulation was designed in which the volume of influx taken into the well had exceeded the kick tolerance. In this case, kick tolerance is effectively an estimation of the maximum size of an influx that can be successfully stopped and circulated out of the wellbore without causing lost circulation. Thus, the increase in choke pressure required to offset the combined loss in hydrostatic pressure and the underbalance caused lost circulation. Furthermore, the influx was never stopped. This condition will generally lead to an underground blowout if it is not corrected. Also, the simulation results of exceeding kick tolerance appear to be quite similar to the constant pump pressure response in Section 12.1.

The key indicators plot, Figure 55, and IPG plot, Figure 56, for the event where kick tolerance has been exceeded demonstrate very similar results to the constant pump pressure kick circulation simulated in Figure 51 and Figure 52. The IPG actual curve shown in Figure 56 demonstrates an immediate deviation at the onset of the kick circulation toward negative Δ pit gain and increase Δ surface pressures. The immediate increase in Δ surface pressures is the result of a continuous influx and gas migration above the weak zone allowing choke pressure to increase as well as the drop in pump pressure due to the loss in hydrostatic pressure in the wellbore below the weak zone.

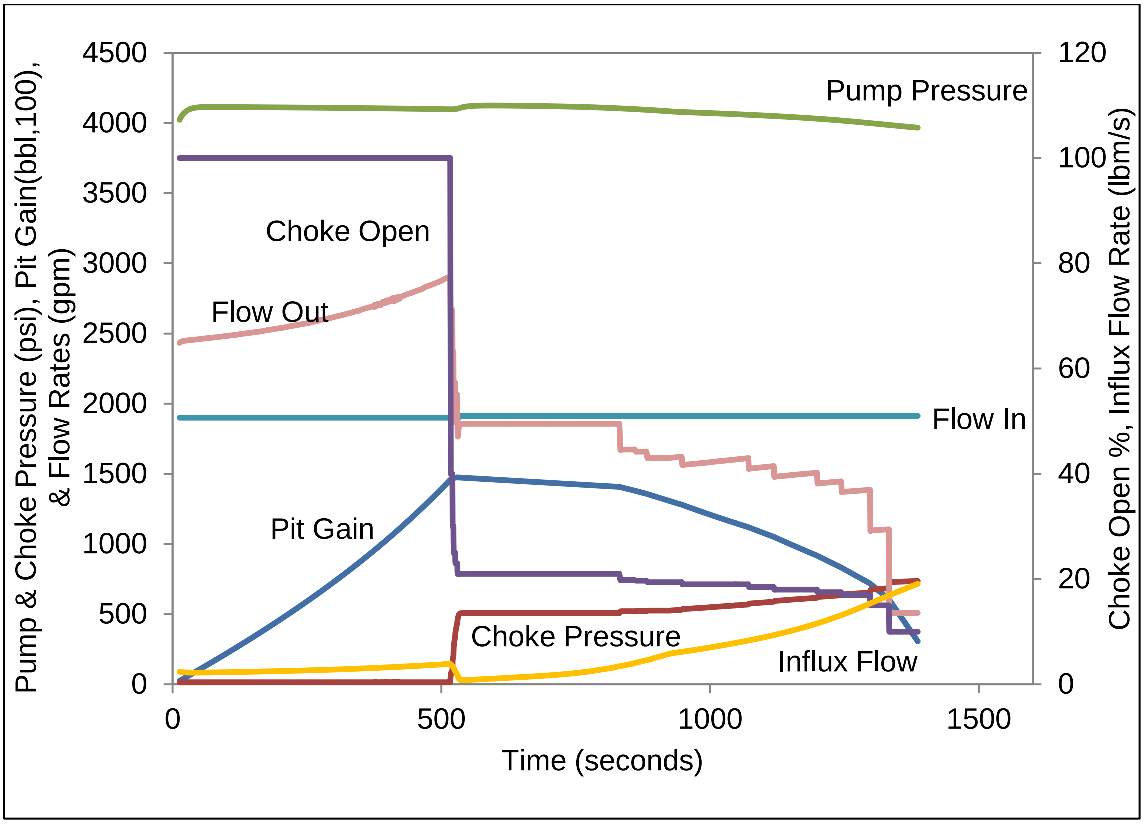

Figure 55: Key indicators plot for an event where kick tolerance has been exceeded

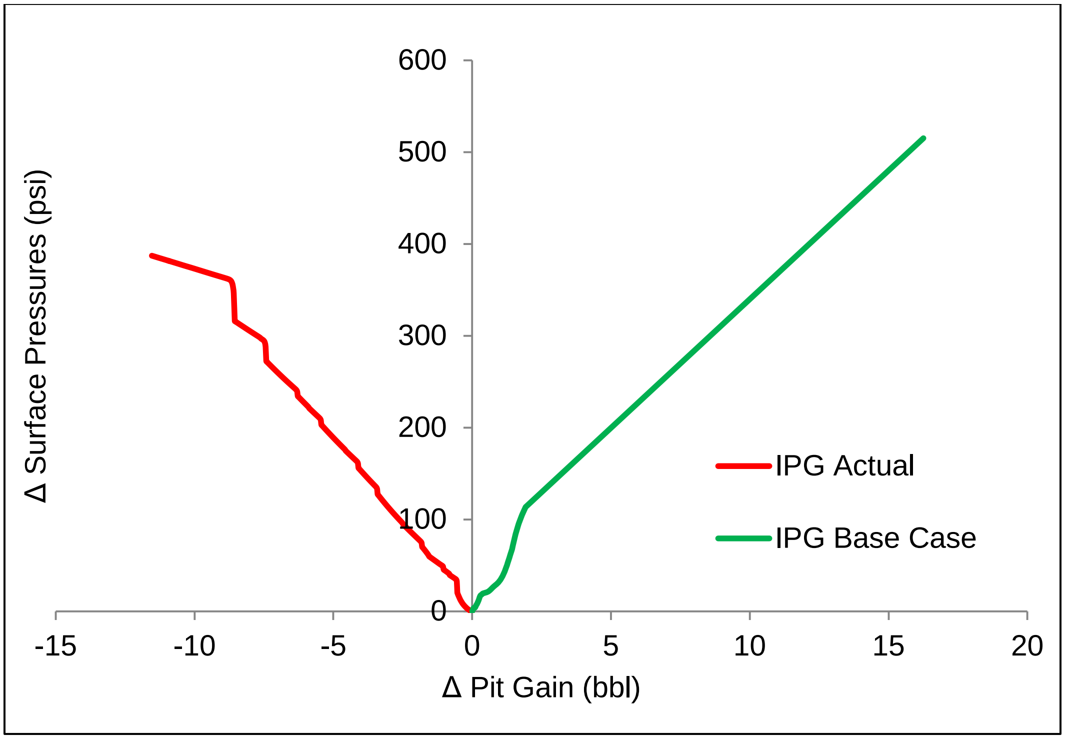

Figure 56: IPG plot for an event where kick tolerance has been exceeded

13 Analysis of Results

This section describes how the attributes of the complications modeled in this research can be utilized to facilitate the diagnosis of a complication and the associated consequences to the wellbore. In order to do so, Section 13.1 will confirm at a fundamental level that deviations from the IPG base case may be used to indicate the onset of a complication. Section 13.2 discusses how the characterization of IPG actual curves can facilitate the diagnosis of a complication and associated consequence. This section also discusses how the IPG method can be deployed to confirm that kick tolerance has not been exceeded while trying to successfully stop and circulate an influx out of the wellbore. A diagnostic indicator for exceeding kick tolerance has not been incorporated into traditional diagnostic methods.

Table 4 summarizes the unique profile of surface indicator behaviors for the complications simulated in this work and described in the preceding chapters. This table also depicts the consequences to the wellbore associated with the onset of a complication over time. Potential consequences may include lost circulation, additional influx, simultaneous downhole loss and influx, or a sustained and unintended change in wellbore pressure. In the event of a complication, rig personnel that are deploying the IPG method may consult with Table 4 to identify the cause of the complication and the resulting consequence.

Table 4 represents a proposed diagnostic approach resulting from this research that merges IPG analysis with more traditional methods. The proceeding analysis will discuss the logic associated with the design of Table 4 and its application to the range of complications studied herein.

Table 4: IPG diagnostic matrix of complications and associated consequences

	Complication	Initial Behavior ΔSP	Initial Deviator (Pump or Choke Pressure Gauge) + = Increasing - = Decreasing	Resulting IPG Actual Slope and ΔPG Direction	Aux. Indicator	Consequence
		Implied Pit Gain Method				
Mud Pump, Drill String, & Bit	Plugged Bit Nozzle	-	Pump +	Base Case Slope		Unintended BHP Decrease
				< Base Case Slope & + ΔPG		Continued Additional Influx in Progress
	Inefficient Pump (Pump Trouble)	+	Pump -	Base Case Slope	Flow out decreases	Unintended BHP Increase
				< Base Case Slope & - ΔPG		Lost Circulation*
	Nozzle Washout	+	Pump -	Base Case Slope		Unintended BHP Increase
				< Base Case Slope & - ΔPG		Lost Circulation*
	Drill String Leak	+	Pump -	Base Case Slope	Continuing ΔSP increase & pump pressure decrease	Unintended BHP Increase
				< Base Case Slope & - ΔPG		Lost Circulation*
	Drill String Part	+	Pump -	Base Case Slope	Follows drill string leak	Unintended BHP Increase
				< Base Case Slope & - ΔPG		Lost Circulation*
Choke/RCD	Choke/RCD Leak	-	Choke - **	≈ Base Case Slope		Unintended BHP Decrease
				< Base Case Slope & + ΔPG		Continued Additional Influx in Progress
	Passive Loss of Control, Choke Size to large	-	Choke - **	≈ Base Case Slope	Corrected choke size removes symptoms and consequence	Unintended BHP Decrease
				< Base Case Slope & + ΔPG		Continued Additional Influx in Progress
	Passive Loss of Control, Choke Size to Small	+	Choke + **	≈ Base Case Slope	Corrected choke size removes symptoms and consequence	Unintended BHP Increase
				< Base Case Slope & - ΔPG		Lost Circulation*
	Partially Plugged Choke (before Remediation)	+	Choke + **	≈ Base Case Slope		Unintended BHP Increase
				< Base Case Slope & - ΔPG		Lost Circulation*
Impending Underground Blowout	Exceed Kick Tolerance	+	Gradual Choke + & Pump -	Depends on operator, generally negative slope due to - ΔPG & + ΔSP		Simultaneous Downhole Influx and Lost Circulation

* During lost circulation, Δ surface pressures is initially relatively constant, but may eventually increase due kick fluids causing loss of hydrostatic pressure above the loss zone

** Pump pressure change is expected too lag choke pressure in the same direction

13.1 Deviations Represent Complications

Significant deviations from the IPG base case curves are indicative of complications occurring during a CBHP kick circulation. In each case, the complication and subsequent response altered the behavior of surface indicators and pit gain from what was previously predicted.. For example, IPG actual curves have a shallower slope in comparison to the base cause in the event of an additional influx due to the fact that the loss in hydrostatic pressure from the continued influx has not been successfully offset with enough choke pressure. When lost circulation occurs, the IPG actual curve proceeds continuously towards a negative Δ pit gain to represent the loss in drilling fluid with relatively horizontal slope. Responses to a complication that intend to or actually do increase wellbore pressure create an initial deviation in the upward direction. Likewise, responses that lower wellbore pressure initially deviate in the downward direction. These initial deviations are due to a sudden change in Δ surface pressures following the onset of a complication. Finally, when performing a kick circulation, a gradual and immediate upward deviation of the IPG actual curve toward a negative Δ pit gain may also suggest that a simultaneous downhole loss and influx event is occurring.

The severity of a deviation between an IPG base case and actual case is indicative of the severity of a complication and its resulting consequence to the wellbore. Thus, complication scenarios with significant changes in Δ surface pressures reflect relatively large leaks and plugs that can require large changes in choke pressure to maintain a target pump pressure. Furthermore, excessive gains or losses in Δ pit gain are a reflection of the amount of lost circulation or additional influx being taken into the wellbore. In contrast, scenarios with relatively small amounts of lost circulation, additional influx or changes in Δ surface pressures may not vary much from the IPG base case at all. Despite the severity of the change in wellbore pressure, a return of IPG actual slope to the IPG base case slope indicates that the wellbore is both intact and not taking any additional influx.

Minor complications that yield only slight deviations from the IPG base case may be difficult to recognize due to the imperfections that may be associated with rig instrumentation and human or automated controls. As result, a kick circulation may experience a minor complication without a substantial deviation from the IPG base case. For example, in the scenario with a passive loss of choke control and no additional influx, both the IPG actual and IPG base case curves appeared to look quite similar within the accuracy, sensitivity and repeatability of rig pressure gauges. Given that the resulting slopes of these two cases are quite similar, one may assume that the consequence of this complication is simply an undesirable change in wellbore pressure.

Figure 57 illustrates that IPG actual curves have deviated from the IPG base case in each scenario simulated in this work. The curve directly below the IPG base case with very little deviation represents a passive loss of choke control with no additional influx which was discussed in the previous paragraph. Such a scenario involves a minor complication with an insignificant consequence. Figure 61 includes partially plugged choke complications that involve the re-routing of flow as well as corrective actions that allow the blockage to clear. These complications are not present on Figure 57 but still support the conclusion that deviations indicate complications.

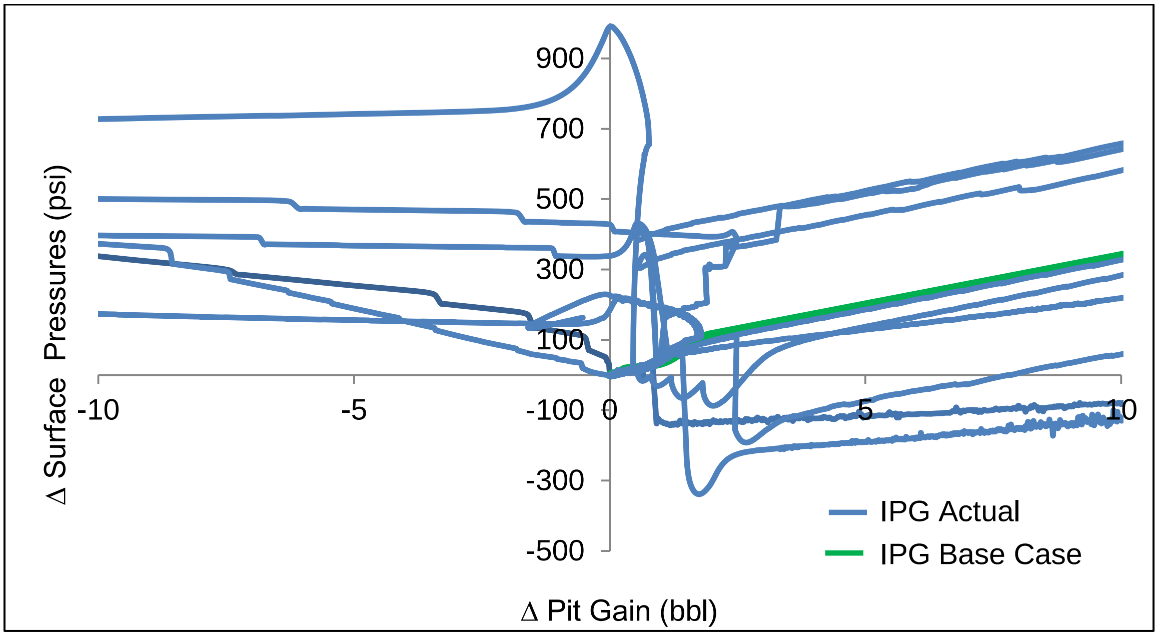

Figure 57: Initial deviation from the base case indicate the onset of a complication

13.2 Interpretation of Deviations from IPG Base Case

The deviations from the IPG base case seen from the scenarios tested in this research demonstrate that the profile of the IPG actual curve contains characteristics that may be useful in diagnosing a complication. The characteristics of the deviations over time can be interpreted by rig personnel to determine if the wellbore is experiencing a sustained change in BHP, lost circulation, second influx, or simultaneous downhole losses and influx. Δ surface pressures and Δ pit gain alone may not conclusively diagnose a specific complication. However, one may make a more specific diagnosis when coupling the initial behaviors of Δ surface pressures and Δ pit gain with data on whether pump pressure or choke pressure deviated first.

13.2.1 Deviations in Δ Surface Pressures

Deviations from the IPG base case in the upward direction are representative of responses to a complication that increase wellbore pressure. The opposite of this statement is also true. Complications that result in an initial increase in wellbore pressure are partially plugged chokes or exceeding kick tolerance. Similarly, the first response to drill string leaks and parts, mud pump inefficiencies, or nozzle washouts is likely to be to increase casing pressure which will also increase wellbore pressure. Complications that initially result in a drop in wellbore pressure are choke and RCD leaks, and a passive loss of choke control. The increase in choke opening that would typically be the first response to a plugged bit nozzle also causes a drop in wellbore pressure.

Figure 58 provides a graphical representation of the IPG actual curves described in the complications matrix in Table 3. Please note that all complications that result in an intended wellbore pressure increase are characterized by upward deviations from the IPG base case shown in blue. Conversely, complications that result in a drop in wellbore pressure are characterized by downward deviations from the IPG base case shown in red. The scenarios representing a cleared choke blockage are not present in this figure, but support this conclusion.

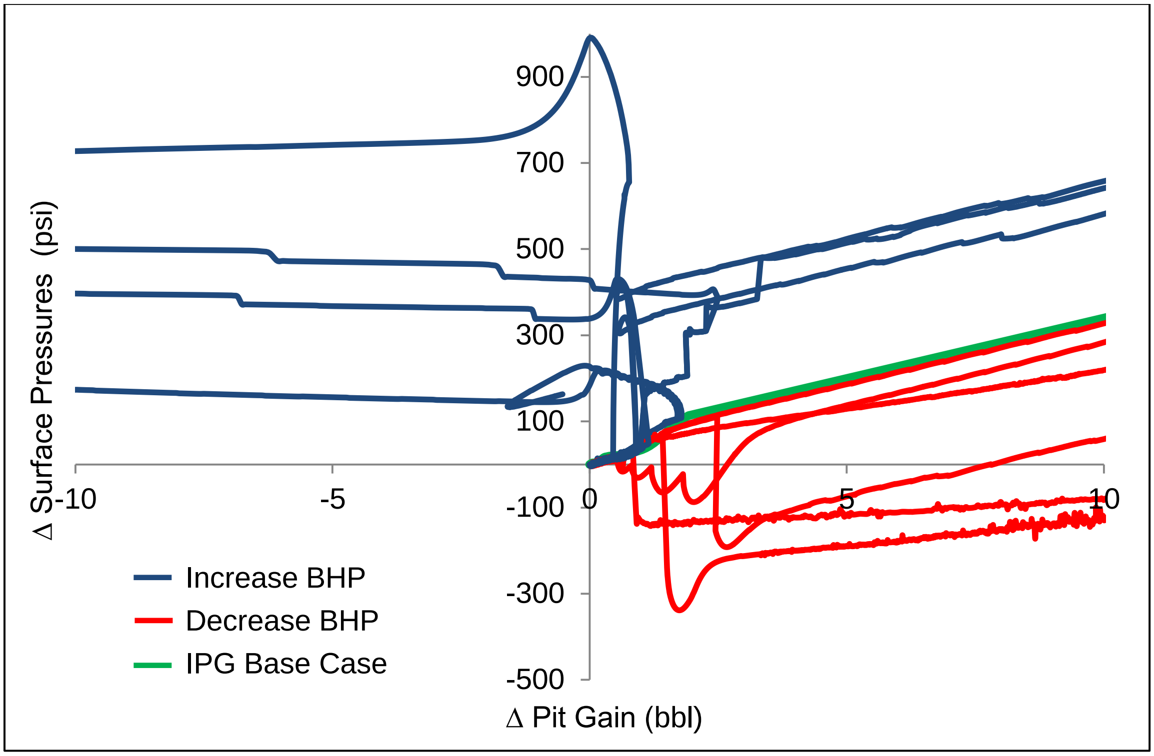

Figure 58: Upward and downward deviation of IPG actual curves from base case

13.2.2 Lost Circulation

A continuous decrease in Δ pit gain that deviates to the left of the IPG base case is a conclusive indicator that lost circulation is occurring. However, a short term reduction in Δ pit gain can be caused by gas compression. Thus, the difference between an intact wellbore with a significant increase in BHP versus a lost circulation case requires observation over time to discern. An example of gas compression momentarily appearing as lost circulation can be seen in the partially plugged choke with no remediation and the wellbore remaining intact scenario in Section 11.1.1. Please note how this curve proceeds toward negative Δ pit gain until gas expansion resumes allowing the curve to proceed to positive Δ pit gain once more. On other hand, the partially plugged choke that caused lost circulation when no corrective action was attempted has an increasingly negative Δ pit gain as seen in 11.1.4.The slope of the IPG actual curve is expected to remain relatively flat without any increase in Δ surface pressures when the column of fluid above the weak zone consists solely of drilling fluid. However, one should note that Δ surface pressures may increase even during lost circulation due to the reduction in hydrostatic pressure as gas rises and expands above the loss zone. This behavior complicates the common expectation that choke pressure will remain flat or fall during lost circulation.

Figure 59 distinguishes the lost circulation scenarios from scenarios where BHP is increased while the wellbore remains intact. Please note that lost circulation scenarios are evidenced by a continued decrease in Δ pit gain. Δ surface pressures are expected to remain flat during the early phase of lost circulation and increase as hydrostatic pressure is lost above the weak zone.

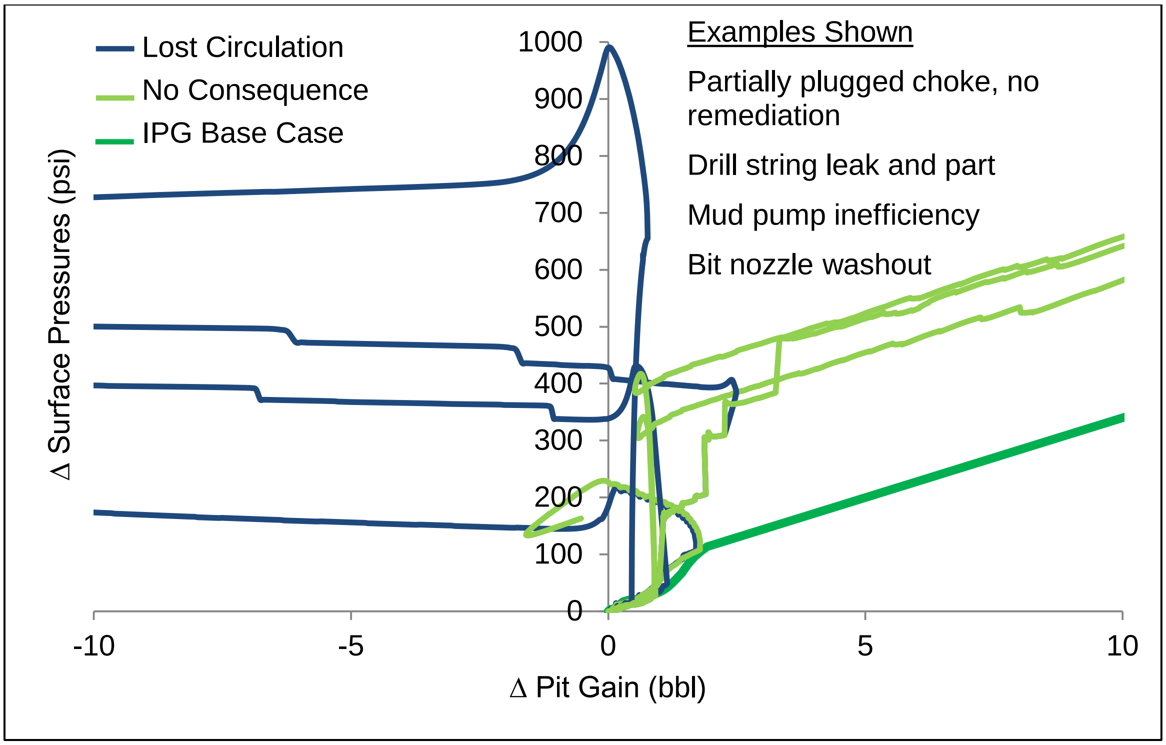

Figure 59: IPG actual Curves representing lost circulation versus an intact wellbore

13.2.3 Continuing Additional Influx

A continuing additional influx is indicated by IPG actual curves that fall below the IPG base case and have a shallower slope as evidenced in Figure 60. Complications that have resulted in a continuing additional influx include a leaking choke/RCD, passive loss of choke control and a plugged bit nozzle. The reduction in slope steepness highlights that the loss in hydrostatic pressure from the increase in gas in the wellbore has not been successfully offset with enough choke pressure. An exception to this conclusion may occur during wellbore breathing which is discussed in Section 13.2.4.

In the event of a drop in BHP that leaves the wellbore remaining overbalanced, the IPG actual curve resumes the same slope predicted for the base case. For example, when comparing a plugged nozzle with and without an additional influx, the plugged nozzle with an additional influx results in a shallower slope than the IPG base case as seen in section 10.1.

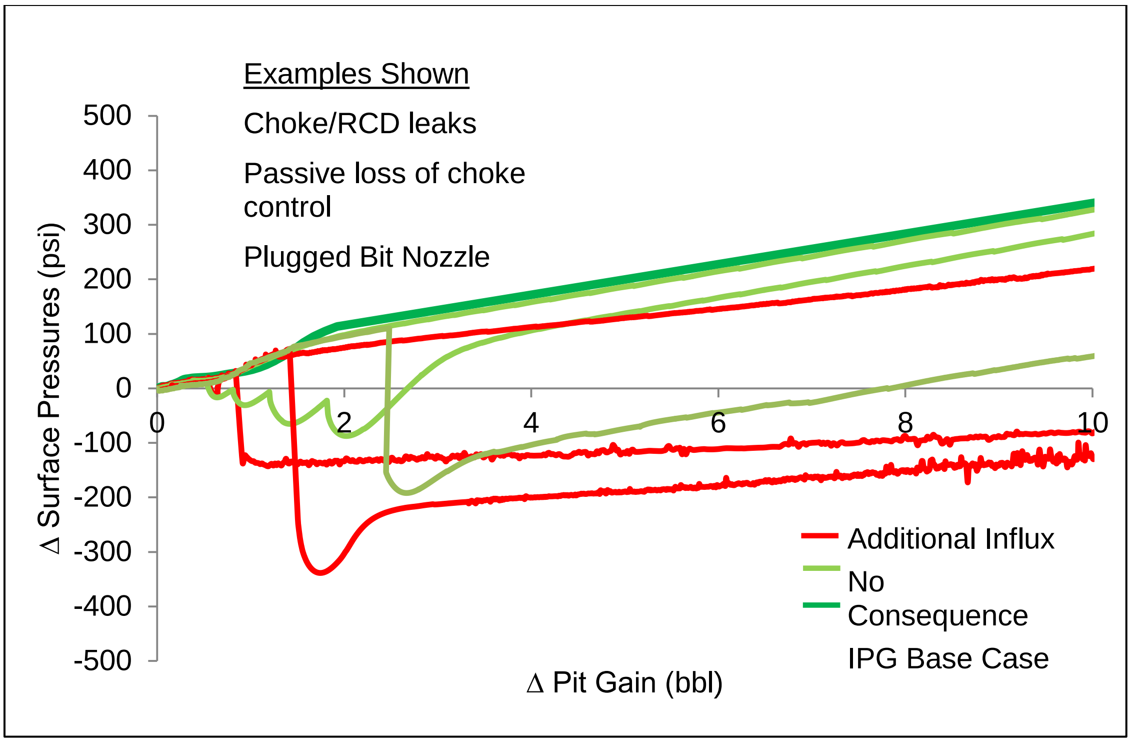

Figure 60: IPG actual curves with a continuing additional influx vs. no additional influx

13.2.4 Wellbore Breathing and Temporary Additional Influx

A partially plugged choke that is subsequently corrected or by-passed results in the IPG actual slope returning to the base case slope in each simulation shown in Figure 61. Simulations of these scenarios provide examples of the different impacts of increases and decreases in BHP, gas compression, temporary loss of returns, wellbore breathing, and a temporary additional influx. A response to clear the blockage can result in the following combinations of temporary consequences: lost circulation, wellbore breathing, and temporary additional influx; lost circulation and wellbore breathing; temporary additional influx; or simply, an undesirable change in wellbore pressure. A response to re-route flow can result in either temporary lost circulation or an undesirable change in wellbore pressure; a temporary additional influx is not likely.

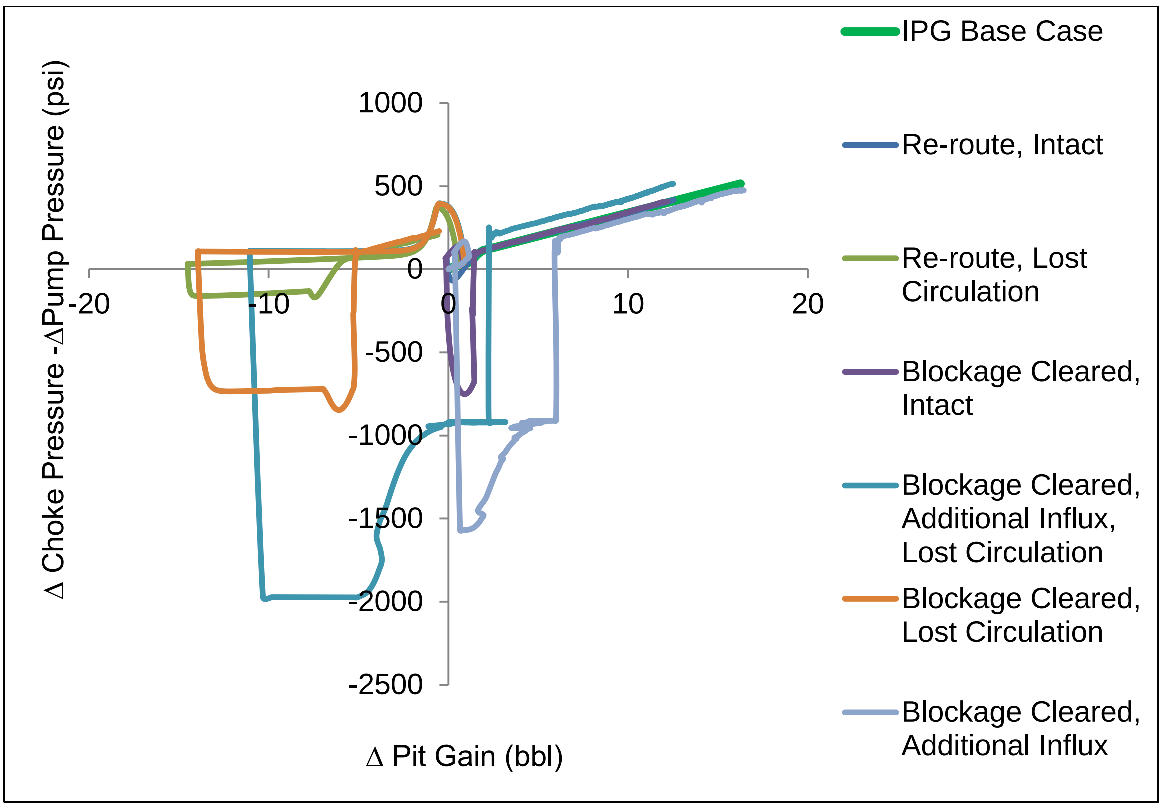

Figure 61: IPG partially plugged choke correction scenarios with wellbore breathing and temporary additional influx and lost circulation

Lost circulation due to the increased BHP from the blockage has the same characteristics described in Section 13.2.2. The only key difference in the partially plugged choke correction scenarios is that lost returns stop when either the blockage has been cleared or when flow has been re-routed to an alternate choke as evidenced by the drop in Δ surface pressures. In these cases where the excess pressure causing lost circulation is corrected, the reduced wellbore pressure causes wellbore breathing, which results in an increasing Δ pit gain.

Wellbore breathing is evidenced by a relatively flat IPG actual slope and an increase in Δ pit gain for a brief period in time. If the wellbore is overbalanced, the end of wellbore breathing is evidenced in these simulations by a dip in Δ surface pressures led by a transient drop in choke pressure from the reduction in flow out and followed by a drop in pump pressure and BHP due to the loss in equivalent circulating density (ECD).

A temporary additional influx will occur if the well becomes underbalanced while clearing the choke. The influx stops when the choke size is reduced to return to the target pump pressure. In any event, once the target pump pressure is obtained, the IPG actual slope will return to the base case slope indicating a CBHP kick circulation with no further consequences.

Simulations experiencing a temporary additional influx do not have a dip in Δ surface pressures following wellbore breathing apparently because a net increase in flow out is sustained. Instead, Δ surface pressures begin increasing in a steep fashion driven by a continued drop in pump pressure due to the reduction in BHP. In any event, once the blockage is cleared, choke size is reduced to return pump pressure to the target value. In doing so, the IPG actual slope returns to the IPG base case slope indicating that a CBHP kick circulation can proceed without consequence. Scenarios where flow is correctly re-routed to an alternate choke should not have a temporary additional influx because choke size should not exceed the original choke size at the onset of the complication.

There are also scenarios where the wellbore does not experience lost circulation, wellbore breathing or a temporary additional influx. As with all other cases, once the blockage is cleared or the flow is re-routed, the slope of the IPG actual curve is expected to return to the predicted slope of the IPG base case.

13.2.5 Simultaneous Downhole Losses and Influx

Das (2007) simulated a scenario in which forcing flow rate out equal to the mud pump flow rate with a rapid choke pressure increase masked a simultaneous downhole loss and influx instead of confirming that an influx had stopped. Based on these circumstances, Das recommended the need for an additional indicator to confirm that an influx has been stopped.

Simulations performed in this research that represent an event where kick tolerance has been exceeded demonstrate that rig personnel can analyze the results of the IPG method to determine the presence of simultaneous downhole loss and influx in the wellbore. In such an event, there is generally a significant deviation from the IPG base case toward a negative Δ pit gain and with an immediate and continuous increase in Δ surface pressures. The immediacy of the upward deviation is attributed to a rise in choke pressure and drop in pump pressure over time. Choke pressure rises despite lost circulation due to the additional influx and gas migration above the weak zone causing hydrostatic pressure above the weak zone to fall. Pump pressure falls as the region of the wellbore below the weak zone loses hydrostatic pressure from the additional influx.

Figure 62 compares the IPG base case with an event where kick tolerance is exceeded as well as a bit nozzle washout with lost circulation for comparison. Please note that lost circulation from the bit nozzle washout is differentiated by the relative stability of Δ surface pressures while progressing towards a decrease pit gain.

Complications that result in solely an additional influx are differentiated by an increase in pit gain with a relative shallow IPG slope as evidenced in Figure 60.

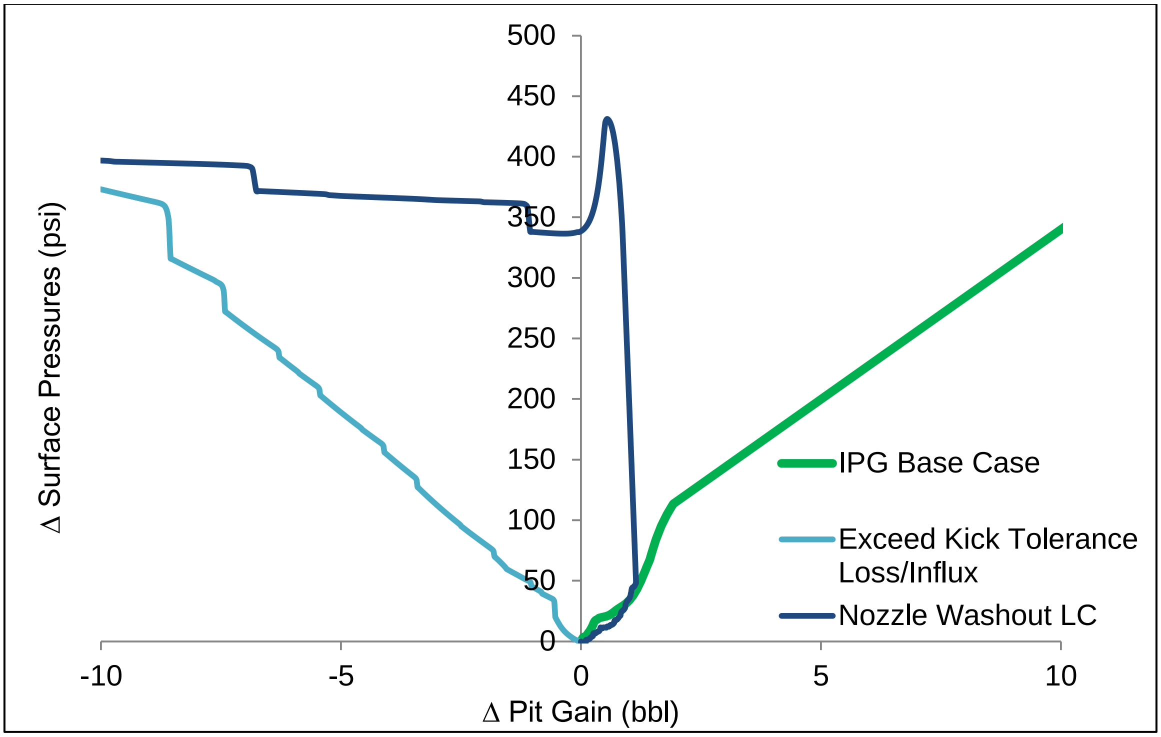

Figure 62: IPG kick tolerance exceeded versus a bit nozzle washout with lost circulation

13.2.6 Identifying the Specific Diagnosis

A means to identify the specific complication solely based on deviation from the IPG base case does not exist. Various complication and consequence scenarios may appear to have similar profiles, i.e. a leaking choke and plugged bit nozzle with a continued influx. However, combining an analysis of IPG actual curve deviations with an indication of whether pump pressure or choke pressure deviated first, may allow a more robust diagnosis.

The diagnostic method proposed by Rehm (1975) was largely dependent on the response of surface pressures to specific complications. The approach was evaluated for the simulations conducted for this study. The response proposed by Rehm was concluded to be an accurate basis for identifying which pressure(s) was expected to deviate and whether the deviation(s) would be an increase or decrease. The notion of determining the initial deviator, pump or choke pressure, to assist in determining the location of a complication is based on generally accepted principles of the impacts of lag time and flow rate on surface pressures that are expected to hold true in the event of a complication.

Thus, one may recognize a change in choke pressure first and pump pressure later due to lag time in the event of a choke being partially plugged or eroded or an RCD leak. This behavior has been observed in the simulations performed in Section 11. Likewise, a drop in mud pump inefficiency causes a drop in pump pressure before any change in choke pressure as evidenced in Section 10.2. Symptoms of a plugged bit or a drill string washout could not be determined conclusively because of limitations of the software used. However, logic supported by Rehm indicates that bit and drill string complications have a significant impact on pump pressure with little or no impact on choke pressure. For example, in the event of a plugged nozzle, one would expect a significant change in pump pressure with very little or no change in choke pressure.

Table 5 provides a summary of this coupling of the IPG Δ surface pressures indicator with the corresponding behavior of which surface pressure deviated first. For example, the inclusion of the initial deviator allows rig personnel to distinguish between a plugged nozzle and leaking choke/RCD in addition to other complications analyzed in this research. Thus, the inclusion of the initial deviator allows the IPG method to both facilitate a diagnosis of the specific complication cause and the resulting consequence to the wellbore.

The auxiliary indicator column in Table 5 can further distinguish between complications that have similar Δ surface pressures and initial deviator combinations. It forms the basis of the causal diagnosis component of Table 4. For example, a nozzle washout and drill string part will both have an initial increase in Δ surface pressures and a decrease in pump pressure as the initial deviator. However, one can infer that a drill string part has occurred if it were preceded by the continuous increase in Δ surface pressures associated with a worsening drill string leak. The auxiliary indicator column is not discussed further as the proposed logic is primarily adapted from Rehm's method.

Table 5: Symptoms identifying a complication

		Implied Pit Gain Method		
	Complication	**Initial Behavior ΔSP**	**Initial Deviator (Pump or Choke Pressure Gauge) + = Increasing - = Decreasing**	**Aux. Indicator**
Mud Pump, Drill String, & Bit	Plugged Bit Nozzle	-	Pump +	
	Inefficient Pump (Pump Trouble)	+	Pump -	Flow out decreases
	Nozzle Washout	+	Pump -	
	Drill String Leak	+	Pump -	Continuing ΔSP increase & pump pressure decrease
	Drill String Part	+	Pump -	Follows drill string leak
Choke/RCD	Choke/RCD Leak	-	Choke - *	
	Passive Loss of Control, Choke Size to large	-	Choke - *	Corrected choke size removes symptoms and consequence
	Passive Loss of Control, Choke Size to Small	+	Choke + *	Corrected choke size removes symptoms and consequence
	Partially Plugged Choke (before Remediation)	+	Choke + *	
Impending Underground Blowout	Exceed Kick Tolerance	+	Gradual Choke + & Pump -	

* Pump pressure change is expected too lag choke pressure in the same direction

14 Practical Comparison of IPG Method to Traditional Methods

The adaption of the IPG method embodied in Table 4 accounts for the behaviors of Δ surface pressures, Δ pit gain and initial deviator in combination with any auxiliary information needed to facilitate the diagnosis of complications. The IPG method also includes columns which detail the potential consequences to the wellbore environment in the time period following the onset of a complication. The following sections will compare diagnostic procedures and capabilities of each method in more detail. The IPG method allows the diagnosis of the apparent consequences to well control. The following sections will compare the diagnostic procedures and capabilities of the IPG method with those of traditional methods.

14.1 Interpretation of Surface Indicators

The behavior of surface indicators accounted for in Rehm's troubleshooting method matches the behaviors recognized with Δ surface pressures in the IPG Method. Table 6 represents the correlations between Rehm and IPG methods for complications occurring in the drill string, bit and mud pump. Table 7 represents the correlations between Rehm and IPG methods for choke and RCD complications. The IPG method includes the "initial deviator" indicator as a useful adaption of Rehm's approach.

For example, in a plugged bit scenario detailed in Table 6, Rehm assumes that pump pressure will initially deviate upward. In order to diagnose the root cause, Rehm suggests that the operator increase the choke opening size to see if pump pressure is reduced. This action will cause a drop in BHP. Along similar lines, the IPG curve will deviate downward following the onset of a plugged nozzle first due to the increase in pump pressure and next due to the drop in BHP as choke size is increased to regain the target pump pressure. The implication that this is a blockage upstream of the choke is based on the increasing pump pressure as the first observed deviator. As mentioned above, Rehm also sought out a similar symptom to diagnose a plugged bit nozzle. In either case, the Rehm and IPG methods both acknowledge a similar pattern in the behavior of surface pressures.

Table 6: IPG and Rehm's method both assume similar behaviors in surface pressures to characterize mud pump, bit, and drill string complications

		Traditional Diagnostic Method				Implied Pit Gain Method Complication Diagnosis		
	Complication	**Pump Pressure**	**Choke Pressure**	**Action**	**Result**	**ΔSP**	**Initial Deviator (Pump or Choke Pressure Gauge) + = Increasing - = Decreasing**	**Aux. Indicator**
Mud Pump, Drill String & Bit	Plugged Bit Nozzle	Up	No Change	Increase Choke Size	Pump Pressure Falls	Down	Pump +	
	Inefficient Pump (Pump Trouble)	Down	No Change	Decrease Choke Size	Pump Pressure Rise	Up	Pump -	Flow out decreases
	Nozzle Washout	Down	No Change	Decrease Choke Size	Choke and Pump Pressure Rise	Up	Pump -	
	Drill String Leak	Down	No Change	Continually Decrease Choke Size	Pump Pressure No Response, Choke Pressure Up	Up	Pump -	Continuing ΔSP increase & pump pressure decrease
	Drill String Part	Down	No Change	Continually Decrease Choke Size	Pump and Choke Pressure Increase	Up	Pump -	Follows drill string leak

Complications pertaining to the choke or RCD result in having limited or no ability to respond to the change in drill pipe pressure because a failure in the choke or RCD is the cause of the change in drill pipe pressure. Despite this additional complexity, the expected behavior of surface pressure is still the same for the Rehm and IPG methods. For example, in the partially plugged choke scenario listed in Table 7, Rehm’s method suggests that choke pressure will deviate in the upward direction at the onset of the blockage. Similarly, the IPG method also suggests that an upward deviation in Δ surface pressures coupled with having a choke pressure increase as the initial deviator can be used to diagnose a partially plugged choke.

Table 7: IPG and Rehm's method both assume similar behaviors in surface pressures to characterize choke/RCD complications

		Traditional Diagnostic Method				Implied Pit Gain Method Complication Diagnosis		
	Complication	Pump Pressure	Choke Pressure	Action	Result	Initial Behavior ΔSP	Initial Deviator (Pump or Choke Pressure Gauge) + = Increasing - = Decreasing	Aux. Indicator
Choke/RCD	Choke/RCD Leak	No Change	Down or No Change	Decrease Choke Size	No Pressure Movement and Pit Volume OK	Down	Choke - *	
Choke/RCD	Passive Loss of Control, Choke Size to large	Down	Down	Decrease Choke Size	Pump and Choke Pressure Increase	Down	Choke - *	Corrected choke size removes symptoms and consequence
Choke/RCD	Passive Loss of Control, Choke Size to Small	Up	Up (same as pump)	Increase Choke Size	Drill Pipe and Choke Pressure Fall	Up	Choke + *	Corrected choke size removes symptoms and consequence
Choke/RCD	Partially Plugged Choke (before Remediation)	Up	Up (same as pump)	Open Choke to clear Blockage	Pressure Fall - OK	Up	Choke + *	

A key difference between the IPG method and Rehm's method is that the IPG method continuously tracks changes in pit gain. Rehm only explores changes in pit gain as needed. The benefit of coupling changes in pit gain with changes in surface pressure is the ability to gain an improved understanding of the consequences of a complication and of one's response following the onset of a complication. Such consequences include the possibility of lost circulation, an additional influx, simultaneous downhole losses and influx, or an intact well with a BHP that is higher or lower than intended. By further expanding on the plugged nozzle example discussed above, while both methods can diagnose the onset of a plugged nozzle, only the IPG method is designed to determine if a drop in BHP has also caused an additional influx. Furthermore, one should also note that Rehm's method does not diagnose events where kick tolerance has been exceeded. Conversely, there are complications included in Rehm's method that were not practical to simulate with Drillbench Kick. Nevertheless, it is expected that combining Rehm's method with the IPG method, as envisioned when applying the matrix in Table 4, will be more advantageous than using only one of two methods.

14.2 Identifying Consequences & Verifying Control

A comparison of the symptoms used to diagnose complications with the IPG method and Rehm's method has been performed for each complication simulated in this research. One should note that only the onset of the partially plugged choke is observed in the comparison. The components of the partially plugged choke scenarios where flow was re-routed or the blockage was cleared are not discussed in details as the focus of the comparison is on the diagnosis of a complication, not remediation.

Both the Rehm and the IPG method describe the same behavior of surface indicators at the onset of a complication. However, the IPG method, as integrated in Table 8 can also determine the consequences resulting from a complication in the wellbore over time. Table 8 provides the consequences component of Table 4. The determination of the consequence associated with a response to a complication is based on the analysis of the resulting slope of the IPG actual curve and whether pit gain is increasing or decreasing. The consequences may include lost circulation, an additional influx, simultaneous downhole losses and influx, or an intact wellbore with a BHP that is higher or lower than intended. This information is not available with Rehm's method but can be critically important as a means to verify whether a well is being successfully controlled after encountering a complication.

Finally, the IPG method provides a strategy for diagnosing the occurrence of simultaneous downhole losses and influx when kick tolerance has been exceeded. Rehm considered this type of complication independent of his diagnostic method. Thus, Rehm did not provide a conclusive means for identifying or determining whether a response to an unexpected influx was successful in regaining well control.

Table 8: Identifying consequences with the IPG method

	Complication	Implied Pit Gain Method: Resulting IPG Actual Slope and ΔPG Direction	Implied Pit Gain Method: Consequence
Mud Pump, Drill String, & Bit	Plugged Bit Nozzle	Base Case Slope	Unintended BHP Decrease
		< Base Case Slope & + ΔPG	Continued Additional Influx in Progress
	Inefficient Pump (Pump Trouble)	Base Case Slope	Unintended BHP Increase
		< Base Case Slope & - ΔPG	Lost Circulation*
	Nozzle Washout	Base Case Slope	Unintended BHP Increase
		< Base Case Slope & - ΔPG	Lost Circulation*
	Drill String Leak	Base Case Slope	Unintended BHP Increase
		< Base Case Slope & - ΔPG	Lost Circulation*
	Drill String Part	Base Case Slope	Unintended BHP Increase
		< Base Case Slope & - ΔPG	Lost Circulation*
Choke/RCD	Choke/RCD Leak	≈ Base Case Slope	Unintended BHP Decrease
		< Base Case Slope & + ΔPG	Continued Additional Influx in Progress
	Passive Loss of Control, Choke Size to large	≈ Base Case Slope	Unintended BHP Decrease
		< Base Case Slope & + ΔPG	Continued Additional Influx in Progress
	Passive Loss of Control, Choke Size to Small	≈ Base Case Slope	Unintended BHP Increase
		< Base Case Slope & - ΔPG	Lost Circulation*
	Partially Plugged Choke (before Remediation)	≈ Base Case Slope	Unintended BHP Increase
		< Base Case Slope & - ΔPG	Lost Circulation*
Impending Underground Blowout	Exceed Kick Tolerance	Depends on operator, generally negative slope due to - ΔPG & + ΔSP	Simultaneous Downhole Influx and Lost Circulation

* During lost circulation, Δ surface pressures is initially relatively constant, but may eventually increase due kick fluids causing loss of hydrostatic pressure above the loss zone

14.3 Additional Insights

Quantifying the relationship between Δ surface pressure and Δ pit gain with the IPG method provides the means to identify that a complication is occurring in the wellbore via deviations from the predicated base case. These changes may serve as an objective indicator to rig personnel that a diagnostic procedure should be executed. On the other hand, traditional diagnostic indicators rely more on the driller's intuition to acknowledge that a change in surface pressure behaviors is significant enough to represent a potential complication.

A second advantage of the IPG method is its ability to track how the behavior of surface indicators in the midst of lost returns can vary over time. For example, Rehm (1975) states that choke pressure may fall or remain relatively constant during lost circulation. This may be the case when the influx is toward the base of a deep well and has a slow rate of expansion. However, the simulations in this research have shown that choke pressure can begin to rise to offset the loss in hydrostatic pressure associated with gas migration and expansion above the weak zone even in the midst of lost circulation.

15 Conclusion

The proposed diagnostic method involves creating an IPG base case plot, comparing the actual results during a circulation to the base case, and using the matrix in Table 4 to interpret that comparison supplemented with routine drilling data.

The IPG method is shown to provide an objective basis, at least within the complications simulated in this study, for informing rig personnel of the onset of a significant complication as well as providing valuable information on the consequences of that complication. IPG actual curves that significantly deviate from the IPG base case, in any fashion, offer evidence that a complication is occurring. Specifically, IPG actual curves that:

- deviate downward from the IPG base case curve suggest a drop in BHP.
- deviate upward from the IPG base case curve suggest an increase in BHP.
- deviate toward negative Δ pit gain for an extended period of time represent lost circulation.
- deviate toward a negative Δ pit gain briefly followed by a continued increase in Δ pit gain are the result of gas compressibility in an intact wellbore and are not a consequence requiring an additional response to maintain well control.
- deviate with a more horizontal slope than predicted over an extended period of time toward positive Δ pit gain represent a continued additional influx.
- deviate with a more horizontal slope than predicted toward a positive Δ pit gain for a short time may be the result of wellbore breathing if preceded by lost circulation.
- deviate towards a negative Δ pit gain with an immediate and gradual increase in Δ surface pressures may imply simultaneous downhole losses and influx from exceeding kick tolerance.

Use of the IPG plot alone is unable to diagnose the specific well control complications when deployed without a supporting indicator. The improved IPG method described in Section 14 that couples the interpretation of the IPG plot with an indicator of whether pump or choke pressure deviated first and in what direction should be useful for making a more robust diagnosis in a manner at least equivalent to Rehm's (1975) method.

Finally, the IPG method also provides a strong advantage versus traditional diagnostic tools by providing a quantitative means to determine whether control is being achieved successfully, i.e. verifying that lost circulation and/or additional influx are being prevented during kick circulation and any response to a complication. Given that these effects may be subtle, masked by control methods, and/or require time to identify subjectively, this can be a critically important capability, especially when matching flow out to flow in was the original criteria for stopping a formation influx.

A return of the IPG actual slope to the IPG base case slope indicates that control has been successful because a CBHP kick circulation is indicated where changes in choke pressure are driven solely by changes in hydrostatic pressure driven by gas expansion. Thus, the presence of lost circulation, additional influx, or both is not skewing the relationship between Δ surface pressures and Δ pit gain.

Analysis of the slope of the IPG actual case can also facilitate the diagnosis of transient events such as wellbore breathing and a temporary additional influx. For example, a shallower slope than predicted in the direction of a positive Δ pit gain can be used to indicate wellbore breathing or a continued additional influx. Wellbore breathing is initiated after a drastic drop in Δ surface pressures following lost circulation and occurs temporarily. A continued additional influx occurs after drop in Δ surface pressures. A temporary additional influx is evidenced by a steep IPG actual slope progressing toward a positive Δ pit gain before returning to the expected slope. In any event, one should note that once the IPG actual slope returns to the IPG base case slope, the presence of wellbore and/or a temporary additional influx are no longer present. Thus, a successful circulation with the CBHP has resumed.

16 Recommendations for Additional Research

Additional investigation is recommended to maximize the effectiveness of IPG as a diagnostic tool.

1. A comprehensive analysis should be performed on the impacts of slip velocity and gas distribution on IPG base case predictions in a wide range of scenarios that vary geometry, inclination angle, and fluid properties.

2. The impact of gas solubility in oil/synthetic based mud on the IPG diagnostic method should be explored. The solution of gas in these drilling fluids prior to reaching the bubble point may change how the IPG base case curve will be developed and its relevance prior to breakout.

3. Interpretations of the IPG actual curves with simulated complications should be compared with field data on complication to validate the characterization of IPG actual behaviors done in this work.

4. Further investigation of the benefits of coupling the IPG plot interpretation with an indicator of whether pump pressure or choke pressure moved first should be performed. Determine whether such an analysis can conclusively confirm whether the complication is occurring on the annulus or injection side of the operation.

5. Identifying and using simulation software that will allow investigating complications while gas is exiting the wellbore is recommended as well.

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Appendix

The source code for the Excel™ model used to prepare an IPG base case prediction is noted in this appendix in three segments, input cells, formula cells, and Visual Basic code. All input cells must be populated for the spreadsheet to work. With regard to survey data, the cells below the last survey data point must be left blank. Also, survey data must be ordered with 0ft (surface) at the top of the list as shown in the screenshot below. Please note that the Excel™ model is protected under copyright law.

In order to run the spreadsheet, one should take the following actions:

1. Clear all cells beneath Row 20 and between column A and AO.
2. Set the Gas Slip Velocity Multiplier to 1 or 0 for gas slip or no gas slip modeling, respectively.
3. Run the IPG base case prediction macro.
4. Clear all cells between column A and AO below the point where gas reaches the surface as noted by the word “surface” in Column Z. These solutions have not been tested.
5. Create an IPG base case plot with the data in columns H and I.

The gas compressibility (Z constant) is calculated automatically with an additional macro once the prediction macro is run. The source code for this functionality is available to the public at: http://www.enrg.lsu.edu/energydata/past/pvtprop

Input Cells and Definitions:

Pump Rate (BPM) Cell C3

Mud Weight (PPG) Cell C4

Annulus Friction (PSI) Cell C5

BHP (PSI) Cell C6

Time to Stop Influx (Minutes) Cell C7

Initial Pit Gain-Upon CBHP Start (BBL) Cell C8

Time until CBHP is started (Minutes) Cell C9

Drill Collars OD (Inches) Cell G1

Drill Pipe OD (Inches) Cell G2

Hole Diameter (Inches) Cell G3

Casing ID (Inches) Cell G4

Drill Collar Length (Feet) Cell G5

Mud PV (cp) Cell G6

Mud YP (lb/100ft^2) Cell G7

Formation Fluid Temp (F) Cell G8

Gradient (Degrees/Foot) Cell G9

Specific Gravity (no units) Cell G10

Gas Slip Velocity Multiplier (no units) Cell G11

Casing Setting Measured Depth (Feet) Cell K2

Survey data must be entered as shown in the screenshot below:

	AQ	AR	AS	AT	AU
1		Well Profile	Well Profile		
2	Plot Point	Well MD	Well VD	Plot Point	Deviation
3	1	0	0	1	0
4	2	10,074	9721	2	11.55
5	3	10,349	9966	3	27.7
6	4	10,623	10205	4	30.9
7	5	10,895	10434	5	34.4
8	6	11,165	10653	6	37
9	7	11,435	10868	7	38
10	8	11,707	11080	8	39.4
11	9	11,982	11291	9	40.4
12	10	12,254	11497	10	40.8
13	11	12,531	11707	11	40.6
14	12	12,805	11916	12	40.2
15	13	13,175	12197	13	41
16	14	13,451	12405	14	41
17	15	13,727	12613	15	41.5
18	16	14,002	12820	16	40.8
59	57	17600	15464	57	46.1
60	58	17675	15516	58	46.1
61					

Formula Cells and Definitions:

Section Cell J5: = 1

Section Cell J6: = 2

Section Cell J7: = 3

Well Location Cell K5: = ‘DC-OH

Well Location Cell K6: = ‘DP-OH

Well Location Cell K7: = ‘DP-CSNG

Section Top (MD) Cell L5: =MAX(AR:AR)-G5

Section Top (MD) Cell L6: =K2

Section Top (MD) Cell L7: 0

Section Bottom (MD) Cell M5: =MAX(AR:AR)

Section Bottom (MD) Cell M6:=L5-.1

Section Bottom (MD) Cell M7:=L6-.1

Capacity Factor (BBL/FT) Cell N5: =(G3*G3-G1*G1)/1029.4

Capacity Factor (BBL/FT) Cell N6: =(G3*G3-G2*G2)/1029.4

Capacity Factor (BBL/FT) Cell N7: =(G4*G4-G2*G2)/1029.4

Capacity (BBL) Cell O5: =N5*G5

Capacity (BBL) Cell O6: =((MAX(AR:AR)-G5)-K2)*N6

Capacity (BBL) Cell O7: =K2*N7

Section Cell P5: = 1

Section Cell P6: = 2

Section Cell P7: = 3

Max Choke Pressure (PSI) Cell K10: =MAX(AB18:AB1048576)

Max Pit Gain (BBL) Cell K11: =MAX(G18:G1048576)

Max Mixture Volume (BBL) Cell K12: =MAX(D18:D1048576)

Max Delta Pit Gain (BBL) Cell K13: =MAX(H18:H1048576)

Max Mixture Length MD (Feet) Cell K14: =MAX(E18:E1048576)

Mixture Volume when influx is stopped (BBL) Cell C10: =(C8+C3*C7)

Mixture Volume bottom upon CBHP start (Feet) Cell C11: =MAX(AR:AR)-IF((C9-C7)*C3>O5,((C9-C7)*C3-O5)/N6,(C9-C7)*C3/N5)

Time Step Total (BBL) Cell A19: 0

Time Step Total (BBL) Cell A20: =A19+B20

Per Time Step (BBL) Pumped Cell B19: 0

Per Time Step (BBL) Pumped Cell B20: 1

Gas Fraction (no units) Cell C19:=Q19/D19

Gas Fraction (no units) Cell C20:=Q20/D20

Mixture Volume (BBL) Cell D19: =$C$10

Mixture Volume (BBL) Cell D20: =(Q20*D19/Q19)+(L19*$N$6)

Mixture Volume Length Measured Depth (Feet) Cell E19:=W19-X19

Mixture Volume Length Measured Depth (Feet) Cell E20:=W20-X20

Mixture Volume (BBL) Cell F19: =IF(Z19="SURFACE",AG19,D19)

Mixture Volume (BBL) Cell F20:=IF(Z20="SURFACE",AG20,D20)

Pit Gain (BBL) Cell G19: =(F19/D19)*Q19

Pit Gain (BBL) Cell G20: =(F20/D20)*Q20

Delta PG (BBL) Cell H19: 0

Delta PG (BBL) Cell H20: (G20-G19)+H19

Delta Surface Pressures (PSI) Cell I19: 0

Delta Surface Pressures (PSI) Cell I20: I19+(AB20-AB19)

Slip Velocity (Feet/Second) Cell J19: =(((($G$7/($G$6^3))^(0.12))*((($C$4-O19)/$C$4)^0.25))*(4.92*C19+1.25))*$G$11*COS(PI()*((VLOOKUP(S19,AS:AU,3,TRUE)+VLOOKUP(R19,AS:AU,3,TRUE))/2)/180)

Slip Velocity (Feet/Second) Cell J20: =(((($G$7/($G$6^3))^(0.12))*((($C$4-O20)/$C$4)^0.25))*(4.92*C20+1.25))*$G$11*COS(PI()*((VLOOKUP(S20,AS:AU,3,TRUE)+VLOOKUP(R20,AS:AU,3,TRUE))/2)/180)

Time (Seconds) Cell K19: =C9*60

Time (Seconds) Cell K20: 60*(B20/$C$3)

Feet Slipped MD (Feet) Cell L19: =J19*K19

Feet Slipped MD (Feet) Cell L20 = K20*J20

Mixture Length Vertical Depth (Feet) Cell M19: =R19-S19

Mixture Length Vertical Depth (Feet) Cell M20 =R20-S20

Mixture Density (PPG) Cell N19: (Q19*O19 +(D19-Q19)*$C$4)/D19)

Mixture Density (PPG) Cell N20: (Q20*O20+(D20-Q20)*$C$4)/D20)

Gas Density (PPG) O19: =(P19)*16/(AD19*80*(AC19+460))

Gas Density (PPG) O20: =(P20)*16/(AD20*80*(AC20+460))

Average Gas Pressure (PSI) Cell P19: =(($C$6-0.052*$C$4*(MAX(AS:AS)-R19)-(1-(W19/MAX(AR:AR)))*$C$5))*0.5+(($C$6-0.052*$C$4*(MAX(AS:AS)-S19)-(1-(X19/MAX(AR:AR)))*$C$5))*0.5

Average Gas Pressure (PSI) Cell P20: =(($C$6-0.052*$C$4*(MAX(AS:AS)-R20)-(1-(W20/MAX(AR:AR)))*$C$5))*0.5+(($C$6-0.052*$C$4*(MAX(AS:AS)-T20)-(1-(U20/MAX(AR:AR)))*$C$5))*0.5

Pit Gain (BBL) Cell Q19: =$C$8

Pit Gain (BBL) Cell Q20 =((P19+14.7)*Q19*AD20*AC20)/((P20+14.7)*AC19*AD19)

Vertical Depth Mixture Bottom (Feet) Cell R19: =((W19-VLOOKUP(W19,AR:AR,1,TRUE))/(VLOOKUP(VLOOKUP(W19,AR:AT,3,TRUE)+1,AQ:AR,2,FALSE)-VLOOKUP(W19,AR:AR,1,TRUE)))*(VLOOKUP(VLOOKUP(VLOOKUP(W19,AR:AS,2,TRUE),AS:AT,2,FALSE)+1,AQ:AS,3,FALSE)-VLOOKUP(VLOOKUP(VLOOKUP(W19,AR:AS,2,TRUE),AS:AT,2,FALSE),AQ:AS,3,FALSE))+VLOOKUP(VLOOKUP(VLOOKUP(W19,AR:AS,2,TRUE),AS:AT,2,FALSE),AQ:AS,3,FALSE)

Vertical Depth Mixture Bottom (Feet) Cell R20: =((W20-VLOOKUP(W20,AR:AR,1,TRUE))/(VLOOKUP(VLOOKUP(W20,AR:AT,3,TRUE)+1,AQ:AR,2,FALSE)-VLOOKUP(W20,AR:AR,1,TRUE)))*(VLOOKUP(VLOOKUP(VLOOKUP(W20,AR:AS,2,TRUE),AS:AT,2,FALSE)+1,AQ:AS,3,FALSE)-VLOOKUP(VLOOKUP(VLOOKUP(W20,AR:AS,2,TRUE),AS:AT,2,FALSE),AQ:AS,3,FALSE))+VLOOKUP(VLOOKUP(VLOOKUP(W20,AR:AS,2,TRUE),AS:AT,2,FALSE),AQ:AS,3,FALSE)

Vertical Depth Mixture Top (Feet) Cell S19: =((X19-VLOOKUP(X19,AR:AR,1,TRUE))/(VLOOKUP(VLOOKUP(X19,AR:AT,3,TRUE)+1,AQ:AR,2,FALSE)-VLOOKUP(X19,AR:AR,1,TRUE)))*(VLOOKUP(VLOOKUP(VLOOKUP(X19,AR:AS,2,TRUE),AS:AT,2,FALSE)+1,AQ:AS,3,FALSE)-

VLOOKUP(VLOOKUP(VLOOKUP(X19,AR:AS,2,TRUE),AS:AT,2,FALSE),AQ:AS,3,FALSE))+VLOOKUP(VLOOKUP(VLOOKUP(X19,AR:AS,2,TRUE),AS:AT,2,FALSE),AQ:AS,3,FALSE)

Vertical Depth Mixture Top (Feet) Cell S20: =((X20-VLOOKUP(X20,AR:AR,1,TRUE))/(VLOOKUP(VLOOKUP(X20,AR:AT,3,TRUE)+1,AQ:AR,2,FALSE)-VLOOKUP(X20,AR:AR,1,TRUE)))*(VLOOKUP(VLOOKUP(VLOOKUP(X20,AR:AS,2,TRUE),AS:AT,2,FALSE)+1,AQ:AS,3,FALSE)-VLOOKUP(VLOOKUP(VLOOKUP(X20,AR:AS,2,TRUE),AS:AT,2,FALSE),AQ:AS,3,FALSE))+VLOOKUP(VLOOKUP(VLOOKUP(X20,AR:AS,2,TRUE),AS:AT,2,FALSE),AQ:AS,3,FALSE)

Vertical Depth Top Estimate (Feet) Cell T19: N/A

Vertical Depth Top Estimate (Feet) Cell T20: =(((U20-VLOOKUP(U20,AR:AR,1,TRUE))/(VLOOKUP(VLOOKUP(U20,AR:AT,3,TRUE)+1,AQ:AR,2,FALSE)-VLOOKUP(U20,AR:AR,1,TRUE)))*(VLOOKUP(VLOOKUP(VLOOKUP(U20,AR:AS,2,TRUE),AS:AT,2,FALSE)+1,AQ:AS,3,FALSE)-VLOOKUP(VLOOKUP(VLOOKUP(U20,AR:AS,2,TRUE),AS:AT,2,FALSE),AQ:AS,3,FALSE))+VLOOKUP(VLOOKUP(VLOOKUP(U20,AR:AS,2,TRUE),AS:AT,2,FALSE),AQ:AS,3,FALSE))

MD Mixture Volume Top Estimate (Feet) Cell U19: 0

MD Mixture Volume Top Estimate (Feet) Cell U20: Note* User should enter reasonable guess

Minimize Cell V19: N/A

Minimize Cell V20: =U20-X20

Measured Depth Gas Mix Bottom (Feet) Cell W19: =$C$11

Measured Depth Gas Mix Bottom (Feet) Cell W20:=IF(B20/VLOOKUP(AE19,$J$4:$P$7,5,FALSE)<=(W19-VLOOKUP(AE19,$J$4:$P$7,3,FALSE)),W19-(B20/VLOOKUP(AE19,$J$4:$P$7,5,FALSE)),W19-(((B20-VLOOKUP(AE19,$J$4:$P$7,5,FALSE)*(W19-VLOOKUP(AE19,$J$4:$P$7,3,FALSE)))/VLOOKUP(AE19+1,$J$4:$P$7,5,FALSE))+(W19-VLOOKUP(AE19,$J$4:$P$7,3,FALSE))))

Measured Depth Gas Mix Top (Feet) Cell X19: =W19-AL19-AO19-AH19

Measured Depth Gas Mix Top (Feet) Cell X20: =W20-AL20-AO20-AH20

Section Mixture Volume Bottom Cell Y19: =AF19

Section Mixture Volume Bottom Cell Y19: =AF20

Section Gas Mix Top Cell Z19: =IFERROR(IF(AI19=0,AF19,IF(AN19=0,VLOOKUP(AJ19,$J$4:$K$7,2,FALSE),VLOOKUP(AM19,$J$4:$K$7,2,FALSE))),"SURFACE")

Section Gas Mix Top Cell Z20: =IFERROR(IF(AI20=0,AF20,IF(AN20=0,VLOOKUP(AJ20,$J$4:$K$7,2,FALSE),VLOOKUP(AM20,$J$4:$K$7,2,FALSE))),"SURFACE")

SG Cell (no units) Cell AA19: =G10

SG Cell (no units) Cell AA20: =AA19

Casing Pressure (PSI) Cell AB19: =$C$6-0.052*(M19)*N19-0.052*($C$4)*(MAX(AS:AS)-M19)-$C$5

Casing Pressure (PSI) Cell AB20: =$C$6-0.052*(M20)*N20-0.052*($C$4)*(MAX(AS:AS)-M20)-$C$5

Temperature Degrees (F) Cell AC19: =$G$8-(MAX(AS:AS)-R19)*$G$9

Temperature Degrees (F) Cell AC20: =$G$8-(MAX(AS:AS)-R20)*$G$9

Z Factor (no units) Cell AD19: =Z(P19,AC19,AA19,0,0,0)

Z Factor (no units) Cell AD20: =Z(P20,AC20,AA20,0,0,0)

Code Section Cell AE19: =VLOOKUP(AF19,$K$4:$P$7,6,FALSE)

Code Section Cell AE20: =VLOOKUP(AF20,$K$4:$P$7,6,FALSE)

Code Gas Bottom Cell AF19: =IF(AND(W19<=$M$5,W19>$L$5),$K$5,IF(AND(W19<=$M$6,W19>$L$6),$K$6,IF(AND(W19<=$M$7,W19>$L$7),$K$7,"Eh")))

Code Gas Bottom Cell AF20: =IF(AND(W20<=$M$5,W20>$L$5),$K$5,IF(AND(W20<=$M$6,W20>$L$6),$K$6,IF(AND(W20<=$M$7,W20>$L$7),$K$7,"Eh")))

Code (BBL) Cell AG19: =IF((W19-VLOOKUP(AF19,$K$4:$O$7,2,FALSE))*VLOOKUP(AF19,$K$4:$O$7,4,FALSE)>D19,D19,(W19-VLOOKUP(AF19,$K$4:$O$7,2,FALSE))*VLOOKUP(AF19,$K$4:$O$7,4,FALSE))

Code (BBL) Cell AG20: =IF((W20-VLOOKUP(AF20,$K$4:$O$7,2,FALSE))*VLOOKUP(AF20,$K$4:$O$7,4,FALSE)>D20,D20,(W20-VLOOKUP(AF20,$K$4:$O$7,2,FALSE))*VLOOKUP(AF20,$K$4:$O$7,4,FALSE))

Code Sect (Feet) Cell AH19: =AG19/VLOOKUP(AF19,$K$4:$O$7,4,FALSE)

Code Sect (Feet) Cell AH20: =AG20/VLOOKUP(AF20,$K$4:$O$7,4,FALSE)

Code Mixture Volume Carry Over (BBL) Cell AI19: =D19-AG19

Code Mixture Volume Carry Over (BBL) Cell AI20: =D20-AG20

Code Section Cell AJ19:
=IF(IF(AI19>0,AE19+1,AE19)=4,"SURFACE",IF(AI19>0,AE19+1,AE19))

Code Section Cell AJ20:
=IF(IF(AI20>0,AE20+1,AE20)=4,"SURFACE",IF(AI20>0,AE20+1,AE20))

Code Mixture Volume in Section (BBL) Cell AK19:
=IFERROR(IF(VLOOKUP(AJ19,$J$4:$P$7,6,FALSE)-AI19>=0,AI19,VLOOKUP(AJ19,$J$4:$P$7,6,FALSE)),0)

Code Mixture Volume in Section (BBL) Cell AK20:
=IFERROR(IF(VLOOKUP(AJ20,$J$4:$P$7,6,FALSE)-AI20>=0,AI20,VLOOKUP(AJ20,$J$4:$P$7,6,FALSE)),0)

Code Sect (Feet) Cell AL19:=IFERROR(AK19/VLOOKUP(AJ19,$J$4:$O$7,5,FALSE),0)

Code Sect (Feet) Cell AL20:=IFERROR(AK20/VLOOKUP(AJ20,$J$4:$O$7,5,FALSE),0)

Code Section Cell AM19: =IFERROR(IF(AN19>0,AJ19+1,AJ19),0)

Code Section Cell AM20: =IFERROR(IF(AN20>0,AJ20+1,AJ20),0)

Code Mixture Volume Carry Over (BBL) Cell AN19: =IF(AJ19="Surface",0,AI19-AK19)

Code Mixture Volume Carry Over (BBL) Cell AN20: =IF(AJ20="Surface",0,AI20-AK20)

Code Sect (Feet) Cell AO19:
=IFERROR(AN19/VLOOKUP(AM19,$J$4:$O$7,5,FALSE),0)

Code Sect (Feet) Cell AO20:
=IFERROR(AN20/VLOOKUP(AM20,$J$4:$O$7,5,FALSE),0)

Visual Base Code

```
Sub NoSlipIteration()
'
' IPG Base Case Prediction Macro
'
' Keyboard Shortcut: Ctrl+Shift+I
'

For a = 20 To 500

SolverOkSetCell:=Range("V$" & a & ""), MaxMinVal:=3, ValueOf:="0",
ByChange:=Range("$U$" & a & ""), Engine:=1, EngineDesc:="GRG Nonlinear"
```

```
SolverSolveuserFinish:=True
SolverFinish

Range("$A$" & a & "").Select
Range(Selection, Selection.End(xlToRight)).Select
Selection.Copy
Range("$A$" & a + 1 & "").Select
ActiveSheet.Paste

Next a


End Sub
```

Vita

Brian Piccolo received a B.S. in Industrial and Manufacturing Engineering from The Pennsylvania State University, University Park, 2005. Following that time, Brian worked as manufacturing engineer in the semiconductor industry and as an associate for a procurement services firm that supported the energy industry. As Brian’s interest in the oil & gas sector of the energy industry grew, he decided to attend Louisiana State University (LSU) to specialize in well control and managed pressure drilling under the guidance of Dr. Smith. Brian plans to complete his M.S. in Petroleum Engineering at LSU in June 2013 and commence full-time employment immediately afterward. Brian also enjoys visiting different places and exploring new cultures. He believes that doing so fosters his ability to think creatively and maintain a heightened awareness of the global impacts of his actions as a professional.