A STUDY TO DETERMINE NECESSITY OF PILOT HOLES WHEN DRILLING SHALLOW GAS ZONES USING TOP HOLE DUAL GRADIENT DRILLING TECHNOLOGY

A Thesis

by

LAUREN KRISTEN KING

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

May 2009

Major Subject: Petroleum Engineering

A STUDY TO DETERMINE NECESSITY OF PILOT HOLES WHEN DRILLING SHALLOW GAS ZONES USING TOP HOLE DUAL GRADIENT DRILLING TECHNOLOGY

A Thesis

by

LAUREN KRISTEN KING

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

Approved by:

Chair of Committee,	Jerome J. Schubert
Committee Members,	Hans C. Juvkam-Wold
	Steve Suh
Head of Department,	Stephen A. Holditch

May 2009

Major Subject: Petroleum Engineering

ABSTRACT

A Study To Determine Necessity of Pilot Holes When Drilling Shallow Gas Zones Using Top Hole Dual Gradient Drilling Technology. (May 2009)

Lauren Kristen King, B.S., The University of Oklahoma

Chair of Advisory Committee: Dr. Jerome Schubert

When drilling offshore, shallow gas hazards are a major concern because of their potential to cause a major blowout. This is a special concern when drilling in shallower water, where the gas influx reaches the rig sooner. A common practice used to avoid the potential dangers of shallow gas is to drill a pilot hole through the shallow gas zone with the hope that the smaller diameter hole will prevent such a large influx. The use of dual-gradient top hole drilling technology would allow for a larger hole to be drilled and the possible gas influx to be killed dynamically, which I have simulated with the use of a top hole dual-gradient simulator.

DEDICATION

To my parents

ACKNOWLEDGEMENTS

Dr. Jerome J. Schubert, thank you for your advice and all of your patience with me in answering all of my questions. I have enjoyed working for you.

Dr. Hans C. Juvkam-Wold, thank you for agreeing to be on my committee, and providing me with knowledge on this subject.

Dr. Steve Suh, thank you for agreeing to be on my committee.

I would also like to thank Arash Haghshenas for all of his help and for sitting with me for hours at a time to solve problems.

I am grateful to all of my family for their support and patience with me as I worked to finish graduate school.

NOMENCLATURE

BHP	Bottomhole Pressure
BML	Below Mudline
BOP	Blowout Preventer
DGD	Dual Gradient Drilling
DSV	Drillstring Valve
HSP	Hydrostatic Pressure
ICP	Initial Circulating Pressure
ID	Inner Diameter
KWM	Kill Weight Mud
MW	Mud Weight
OWM	Old Weight Mud
RBOP	Rotating Blowout Preventer
SICP	Shut In Casing Pressure
SIDPP	Shut In Drillpipe Pressure
SMD JIP	SubSea MudLift Drilling Joint Industry Project
TD	Total Depth
TVD	True Vertical Depth

TABLE OF CONTENTS

LIST OF FIGURES

Page

LIST OF TABLES

CHAPTER I

INTRODUCTION

Shallow gas zones are a major concern in offshore drilling because of their potential to quickly cause kicks or blowouts, which may cause rig loss, loss of hole, or even death. A strict definition has not been given to shallow gas blowouts, but for this project it will be defined as a blowout before the blowout preventer (BOP) is set (Holand 1997). Drilling through this zone is typically called tophole drilling. While drilling, a kick can occur if the formation pressure is greater than the wellbore pressure and if the formation permeability is high enough to allow the formation to flow (Sandlin 1986).

Research has been done to find the best ways to prevent shallow gas blowouts from occurring, and the common practice is to drill a pilot hole. Pilot holes are smaller, causing a greater chance of swabbing. Holand (1997) noted that swabbing caused 20% of shallow gas blowouts in exploration wells and 40% of the shallow gas blowouts in development wells (Choe and Juvkam-Wold 1999).

Floating rigs are usually used in deep water and have the ability to be moved away from the well if there is a possibility of a blowout. Bottom-supported platforms, used in intermediate or shallow water, do not have that luxury and require a diverter so the gas influx does not come directly up the wellbore to the rig floor. Floaters are commonly used without a riser to drill the tophole section, allowing seawater to be the

---

This thesis follows the style of *SPE Drilling & Completion.*

drilling fluid. However, this does not allow enough hydrostatic pressure to control the well if a kick were to occur (Holand 1997). Furthermore, returns are circulated to the seafloor by a method called "pump and dump," creating an open system. If the influx reaches the surface, the density of the water will be greatly reduced, potentially causing the platform to be submerged. Dual gradient drilling (DGD) bridges this gap with the ability to create a closed loop system and allow more control of wellbore hydrostatic pressure. This project investigates the use of DGD for elimination of the pilot hole for floaters and bottom-supported rigs. The project will evaluate different hole sizes, hole depths, and water depths, and how they affect influx rate, kick height, and reaction time. The main objective of my research is to use a tophole dual-gradient simulator to simulate 12 runs with a pilot hole in shallow water, 12 runs without a pilot hole in shallow water, 12 runs with a pilot hole in deep water, and 12 runs without a pilot hole in deep water to compare influx rates, kick heights, and reaction time.

Kicks

A kick is an influx of formation fluids into the wellbore. In order for a kick to occur, the pore pressure of the formation must be greater than the wellbore pressure, and the permeability of the formation has to be large enough to allow flow (Sandlin 1986).

Kicks can be caused by several different occurrences: drilling into gas, improper hole filling, swabbing, loss of circulation, and insufficient mud weight. Drilled gas is more commonly a problem at shallow depths, causing a shallow gas kick, which will be discussed later. When drilling into overpressured formations, the mud weight will likely not be sufficient, causing gas to travel into the wellbore. Drilled gas would not be such a problem if it did not expand as it travels up the wellbore. What may seem to be a small amount of gas at total depth (TD) may turn into a very large influx at surface (Goins, Ables 1987).

When pulling pipe out of the hole while tripping, drilling mud must replace the volume of steel that is being taken out of the wellbore to maintain enough hydrostatic pressure to prevent an influx from occurring. A common practice is to fill the hole every so many stands, depending on depth and pressure. This is usually done using a trip tank (Goins, Ables 1987).

Swabbing occurs when pipe is pulled out of the hole too quickly. This action essentially “pulls” the gas out of the formation and into the wellbore. The reduction in hydrostatic pressure by swabbing depends on how fast the pipe is pulled, mud weight, and wellbore geometry. Swabbing is particularly a problem in shallow wells where gas is present. However, the large hole sizes associated with shallow wells help against the reduction in hydrostatic pressure. As will be discussed, this is a problem with drilling pilot holes (Goins, Ables 1987).

The fluid level in the wellbore drops when circulation is lost, resulting in loss of hydrostatic pressure. Lost circulation occurs in zones where the formation pressure is less than the wellbore pressure. If the hole is uncased, one formation may start taking the drilling fluid, while another formation leaks gas into the wellbore. Close attention must be kept to plan ahead for lost circulation zones (Sandlin 1986).

All of these causes of kicks are interrelated, but insufficient mud weight plays a key role in every cause. Even small variances in mud weight can cause drastic consequences. Rigs are equipped with several monitors that should be watched closely for signs of insufficient mud weight. Knowledge of how and why kicks occur is essential because kicks that go unnoticed can turn into a blowout, an uncontrolled flow of fluids from the wellbore, which may result in losing the well, the rig, and even a life (Holand 1997).

To prevent this from occurring, there are several ways for detecting a kick: a break in drilling, flow increase, pit gain, an increase in speed of surface pumps, and well flow. The driller's station monitors drilling rate, so the driller must pay close attention to any changes in penetration rate that may be caused by an influx. An increase in flow can be detected by a sensor in the flowline or the pump stroke counter. If the surface pump speed increases, an influx may have increased the flow rate in the annulus. A change in pit volume is indicated by a float that is connected to a recording device on the rig floor. Alarms are typically set if the pit volume gets too low or too high. A high pit gain indicates an influx into the wellbore. A decrease in pit volume can indicate that the drilling fluid is being lost into another formation. Another indication of a kick is if the well flows when the pumps are shut off (Bourgoyne et al. 1986).

Once a kick has been detected, the proper steps must be taken in order to control the influx before it leads to a blowout. The first step is to shut-in the well to prevent the influx from increasing. Once the pressure inside the wellbore equals the pressure of the kicking formation, the kick will stop flowing into the wellbore. As soon as the well is shut-in, the shut-in drill pipe pressure (SIDPP), shut-in casing pressure (SICP), and pit gain must be measured. This is a fairly easy procedure when drilling is conventional and without a drillstring valve (DSV). When the well has stabilized after being shut-in, a gauge on the standpipe will read the SIDPP, which is the difference between the bottom hole pressure (BHP), or the pressure of the formation, and the hydrostatic pressure (HSP) of the mud in the drillstring. Another gauge on the casing annulus reads the SICP, and the pit gain can be measured by the PVT equipment. The SIDPP, true vertical depth (TVD), and old weight mud (OWM) can be used to calculate the kill weight mud (KWM) that will be used to kill the well without fracturing the formation.

$$KWM = \frac{SIDPP}{.052xTVD} + OWM \quad \text{...(Eq.1)}$$

This procedure stays the same for conventional drilling without a DSV, but well control procedures become a little more challenging in DGD, which will be discussed in Chapter II (Watson et al. 2003).

After shutting-in the well and taking the proper measurements, the influx can be circulated out and the well killed by a few different methods. The three most common methods are the Driller's Method, Wait & Weight Method, and the Concurrent Method. I will only discuss the Driller's Method because it was the only one used in all of the simulations. First, the BHP should be kept constant. The next step is to circulate the influx out of the wellbore. This is done by opening the choke and starting the pump. The SICP should be kept until the pump reaches the calculated kill rate. The calculated initial circulating pressure (ICP) should be held constant until the influx has been completely circulated out. Then the pumps are slowed down to a stop and the choke is closed. If the standpipe pressure and casing pressure both read the initial SIDPP, the kick has been circulated out completely. Now the KWM can be pumped down the drillstring at the kill rate while keeping the casing pressure constant until the KWM reaches the annulus. At that point, the drillpipe pressure needs to be used to keep the BHP equal to or slightly greater than the pore pressure until the KWM reaches the choke. A drillpipe pressure decline schedule can be calculated to make sure the kill operation runs smoothly. The pumps can be shut off, and the choke can be closed. To make sure the kill procedure worked, the choke is re-opened to check for flow (Watson et al. 2003, Schubert et al. 2003).

Shallow Gas Kicks

Shallow gas kicks are caused by the same occurrences that cause other kicks. However, shallow gas kicks may be harder to control. The Norwegian Sintef Research Organization studied 172 blowouts around the world and discovered that the most serious cause of kicks that lead to blowouts is shallow gas (Sandlin 1986).

The margin of overbalance, when drilling through shallow zones, does not create a large pressure differential over the formation. If gas is encountered at these shallow depths, a small amount of gas entering the wellbore can greatly decrease the hydrostatic pressure (Goins, Ables 1987).

In the case that a shallow gas kick does occur, the well may not be able to be shut-in because the pressure may surpass the fracture pressure below the casing seat, and there is a possibility of an underground blowout, which could rupture the casing. This would be an expensive problem to fix. Because the well cannot be shut-in, a diverter system is used instead of a BOP. The diverter system directs the influx away from the rig. Precautions must be taken so the diverter system cannot shut-in on the well. Also, the diverter lines must have a large diameter and few turns to prevent a large amount of backpressure on the formation (Sandlin 1986).

Though the diverter system helps in the occurrence of a shallow gas kick, there are common practices to prevent a shallow gas kick from occurring. Before drilling a well, it is extremely important to investigate the area for shallow gas by seismic or data from offset wells. Knowledge of shallow gas may not be as easy when drilling exploration, so the best prevention is to be prepared with the proper equipment and training. Another common practice is the use of a pilot hole. A pilot hole is a smaller diameter hole that is drilled through the potential gas zone and then enlarged to the proper size to set the casing (Sandlin 1986).

The reason for drilling a pilot hole is for well control purposes. When an influx enters the wellbore, the KWM can be pumped downhole at a high circulation rate with the help of the smaller diameter wellbore. The size of the pilot hole is dependent on water depth, depth of the gas zone, wellbore plans, and reservoir characteristics. Simulators have been created to choose the most ideal pilot hole size based on these factors and more (Sandlin 1986).

CHAPTER II

DUAL GRADIENT DRILLING

Typically, when drilling offshore, a riser is used as the connection between the rig floor and the mudline. The pressure at depth includes the weight of the mud in the wellbore and the weight of the mud in the riser. Drilling with a riser is not usually a problem if there is a large pore pressure/ fracture pressure window or shallow water, but it puts limits on water depth and the depth of the target zone (Smith et al. 2001).

Dual gradient drilling, sometimes called riserless drilling, is a drilling system that relies on sea water density and mud weight. The pressure at depth includes the weight of the mud in the wellbore and the weight of seawater in the riser. In deepwater drilling, this increases the margin between pore pressure and fracture pressure, allowing greater depths to be reached. In 1996, a group of operators, drilling contractors, and service companies got together to make this happen with the SubSea MudLift Drilling Joint Industry Project (SMD JIP) (Smith et al. 2001).

DGD uses a mudlift pump on the seafloor to circulate the mud from the annulus through a small diameter return line to the rig floor. A rotating blowout preventer (RBOP) separates the mud in the wellbore from the seawater in the riser. The subsea pump inlet pressure can be changed between constant inlet pressure and constant circulation rate. In my simulations, I used a constant inlet pressure equal to the seawater hydrostatic to simulate a “pump and dump” method. This also allows the use of a heavier weight mud at larger depths (Schubert et al. 2002).

The DGD system provides many advantages when compared to conventional drilling. Using DGD, the pressure at depth inside the wellbore is less than with conventional drilling, allowing the ability to stay within the pore pressure/fracture pressure window. This allows for fewer casing strings and greater setting depths. Larger production tubing can also be run inside the larger casing strings, increasing production rates, which makes the wells more economical. Also, because the riser stays filled with seawater, the cost of drilling mud is reduced. Furthermore, the tension on the riser is decreased because the heavy mud does not apply as much stress. This allows for smaller rigs to use DGD (Schubert et al. 2003).

Well Control

Though there are many advantages to DGD, the challenges associated with DGD are lack of training and well control. DGD technology has not been widely used, so there are not very many case studies to use for learning purposes. However, it has been tested to study the best well control practices involved with DGD. Only the Driller's Method will be discussed. The kick indicators used in DGD are the same as for conventional drilling, but they may be more accurate because the pressure gauges used in DGD are more sensitive. An immediate problem seen for well control is the u-tubing effect when the pumps are shut off. The large column of mud in the drillstring will flow into the annulus in an effort to make the pressure inside the drillstring equal the pressure in the annulus. To prevent u-tubing from occurring, a special DSV was designed. This DSV supports the column of mud in the drillstring, allowing the subsea pumps to continue running when an influx enters the wellbore. In the case that an influx enters the wellbore, the well needs to be shut-in. Shut-in and well control procedures depend on whether or not a DSV is used. When a DSV is used, the well can be immediately shut-in, and the well can be killed similar to conventional methods. The pit gain can be measured conventionally because the DSV prevents u-tubing. The positive opening pressure of the DSV is constantly measured while taking the kick. When the well is shut in after taking a kick and the subsea inlet pressure has stabilized, pressure is put on the DSV, and the opening pressure of the DSV is measured. The difference between the post-kick opening pressure and the pre-kick opening pressure is the SIDPP. The SICP is measured by the subsea pump inlet pressure. When a DSV is not used, the well cannot be shut in, and the mud is allowed to u-tube into the annulus, which allows more influx to enter the wellbore. To measure the volume of influx, the pit gain is measured before and after the u-tubing. The influx volume is the difference between the final pit gain and the estimated u-tube volume. To stop the kick and circulate it out, the circulating drillpipe pressure is measured, the subsea pumps are slowed to the pre-kick rate, and the drillpipe pressure is stabilized. The kick is circulated out at the drillpipe pressure and circulating rate that was recorded at the stabilized drillpipe pressure. The increase in the stabilized drillpipe pressure over the initial circulating drillpipe pressure plus the annular pressure equals the SIDPP. The subsea pump inlet pressure is adjusted to keep the drillpipe pressure constant. Once the kick has been circulated out, the KWM is circulated through the wellbore (Schubert et al. 2003).

Dual Gradient Drilling and Shallow Gas

DGD was created because of the challenges that are encountered when drilling in intermediate to deep water, but this technology will also be applied to shallow water for this project. As discussed earlier, the common practice, when shallow gas is expected, is to drill a pilot hole. Marken et al. (2000) simulated tophole drilling without a riser. The goal was to eliminate the pilot hole, but the results indicate that the pilot hole is necessary when a riser is not being used. The goal of this project was similar, except that I used tophole DGD technology in the simulations.

A former student at Texas A&M University and a professor at Texas A&M University, Choe and Juvkam-Wold, 1999 created an SMD simulator. This simulator has allowed other students, including me, to research DGD technology to find new ways that it can be implemented. The use of this simulator will allow me to investigate whether the pilot hole can be eliminated when using DGD technology to drill the tophole portion of a well in deep water and in shallow water.

CHAPTER III

SIMULATION & RESULTS

Procedure

This research project will be completed with Choe's tophole dual-gradient simulator. The project will consist of four sets of simulator runs. One set will include a pilot hole in shallow water, one set will include a pilot hole in deep water, one set does not include a pilot hole in shallow water, and the last set does not include a pilot hole in deep water. Each set will require the same steps to input the data, with several variables changing.

Simulator Input

When starting a simulation, the default data needs to be changed by clicking on the Change Input Data button, as shown in **Fig. 1.** The screen in **Fig. 2** shows the control data. For the requirements in this project, nothing on the Control Data screen should be changed. The Next button at the top of the screen will be clicked.

Fig. 1—Main Menu. The Change Input Data button must be clicked to change the default data.

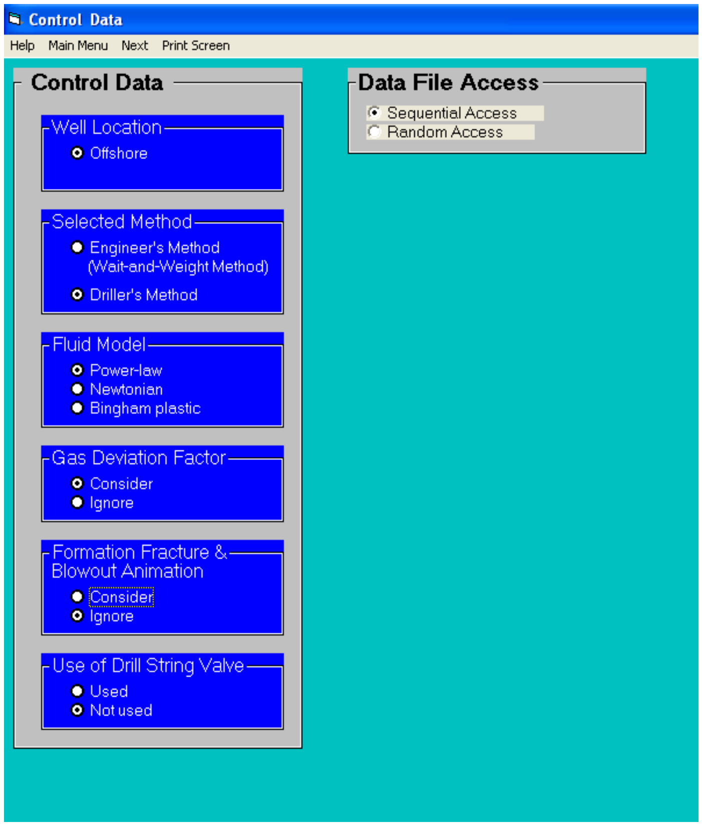


Fig. 2—Control Data. The control data should remain the same for this research project.

Some data in the Fluid Properties and Bit Nozzle Data screen **(Fig. 3)** will need to be changed. The Shear Stress Readings and Old Mud Weight need to be changed because different mud properties are required for the different wellbore depths. The other variables remain the same for this project.

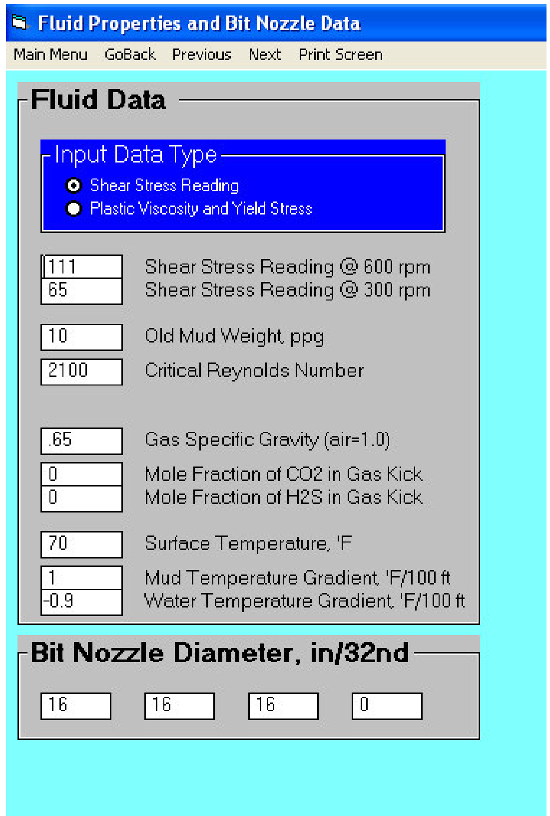


Fig. 3—Fluid Properties and Bit Nozzle Data. As well depth changes, pore and fracture pressure gradients change, requiring that mud properties be changed also.

Each simulator set will have three different water depths and two different well depths, so much of the Well Geometry and Subsea Pump Data will change **(Fig. 4).** The number and inner diameter (ID) of the main return line and second return line, the ID of the choke line and kill line, sea water density, and amount of subsea pump inlet pressure will remain the same for every run. The subsea pump inlet pressure will be equal to 0 psi above seawater hydrostatic on every run in to simulate the “pump and dump” method.

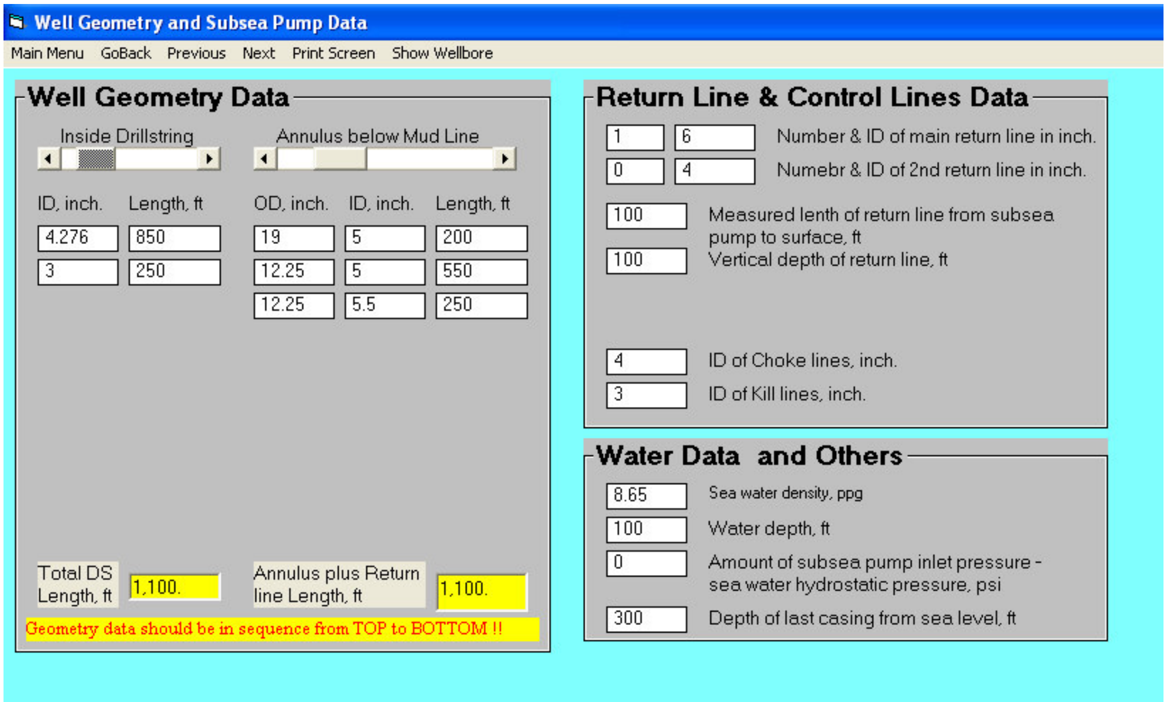


Fig. 4—Well Geometry and Subsea Pump Data. Well depth and water depth will vary in both simulator sets, so the proper data will need to be changed in this screen.

In **Fig. 5,** the amount of formation overpressure will vary between 0.5 and 1 psi, which will then calculate the kick intensity, kill mud weight, and required increase in drill pipe pressure. The pore and fracture pressures will be input. The user input is based on the same pore and fracture pressures from Elieff (2006) because they are based on typical Gulf of Mexico pressure windows. The formation properties will all stay constant. Skin factor will always be 0 to simplify the image of the wellbore. Skin factor represents the amount of damage around the wellbore. For this project, we will assume no damage around the wellbore.

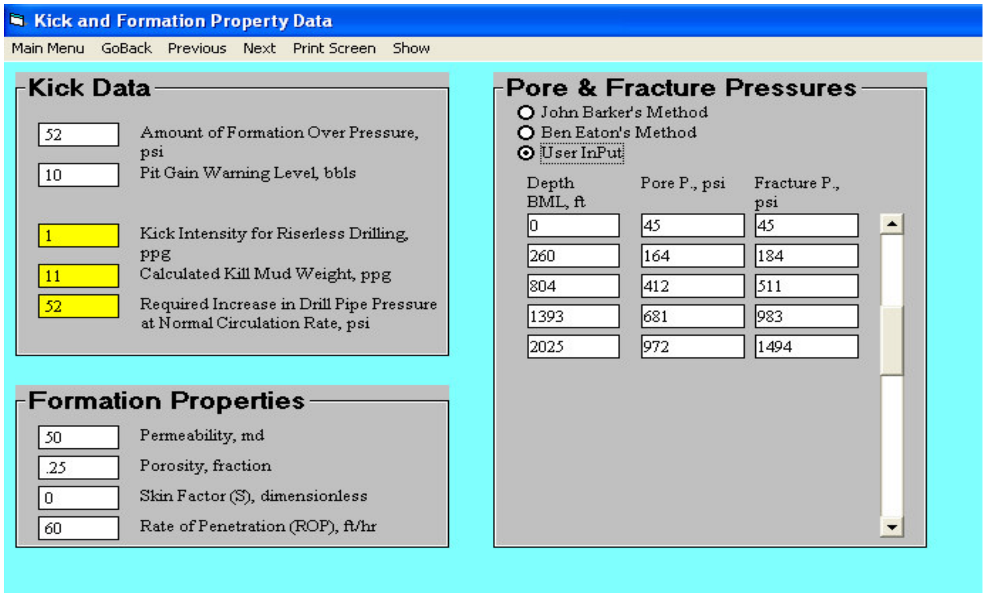


Fig. 5—Kick and Formation Property Data. The yellow boxes can be manipulated by inputting different amounts of formation pressure and pit gain warning level. The formation properties and pore and fracture pressures should remain constant for every run because we are only concerned with the differences in the kicks by depth.

The pump data and surface data can be seen in **Fig. 6.** These variables will remain constant throughout to compare how quickly the kick can be controlled at different water depths and wellbore depths.

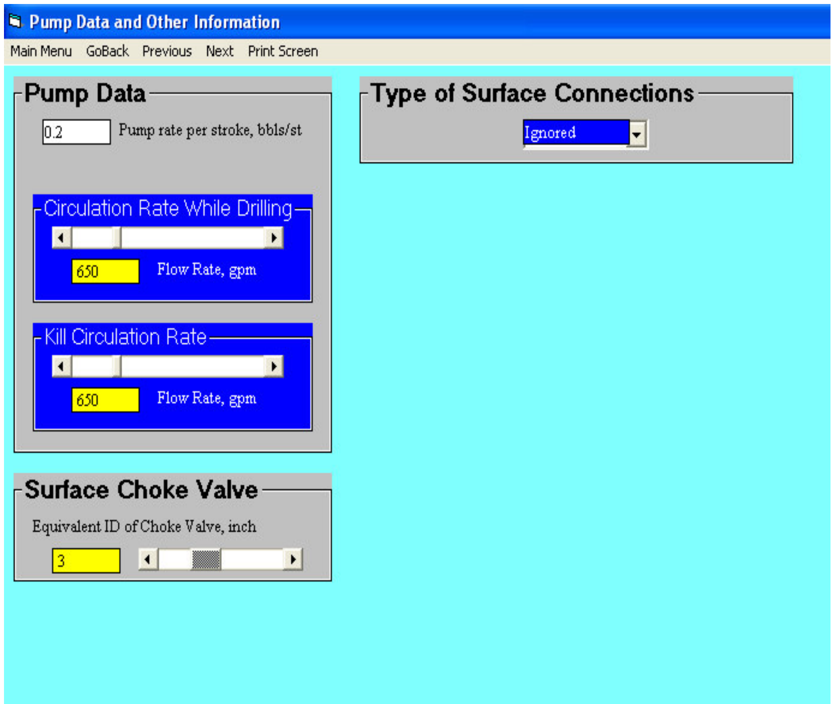


Fig. 6—Pump Data and Other Information. The pump and surface data should remain constant for all of the simulations.

When all of the data has been input into the simulator, the Kick Simulation button will be clicked, as seen in Fig. 1. The window shown in **Fig. 7** will appear.

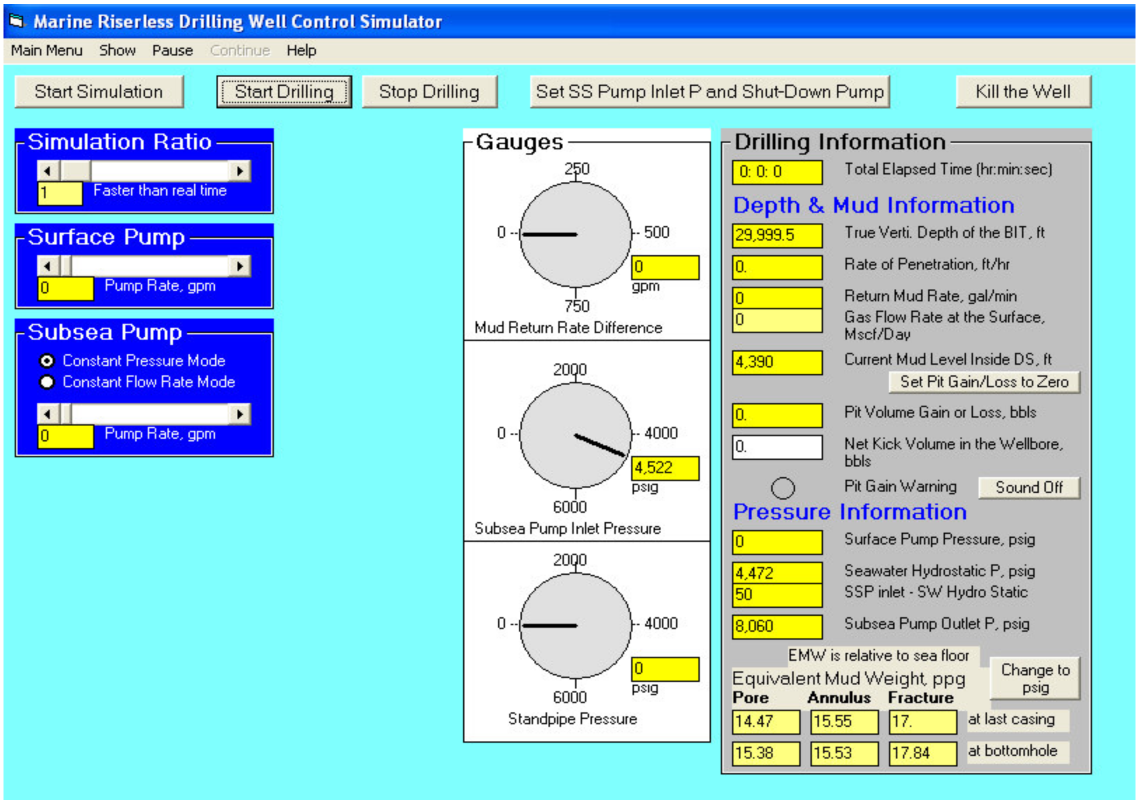


Fig. 7—Start Simulation. The gauges and the values in the yellow boxes are monitored to watch different depth, mud, and pressure information as the well is drilled. This window also shows when the kick occurs and how long it takes to reach the surface.

The next steps are for Procedure 1 and must be followed carefully for accurate simulations:

1. Move the Simulation Ratio to 10X faster than real time.

2. Change the Surface Pump to 650 gpm.

3. Click Start Simulation.

4. Allow the drillstring to fill up with mud. The Subsea Pump will move to 650 gpm.

5. Click Set Pit Gain/Loss to Zero and Start Drilling.

6. When the Pit Gain Warning goes off, click Constant Flow Rate Mode and set the pump rate back to 650 gpm.

7. Allow the bottomhole pressure in the annulus to reach the bottomhole pore pressure **(Fig. 8).**

8. Click Kill the Well.

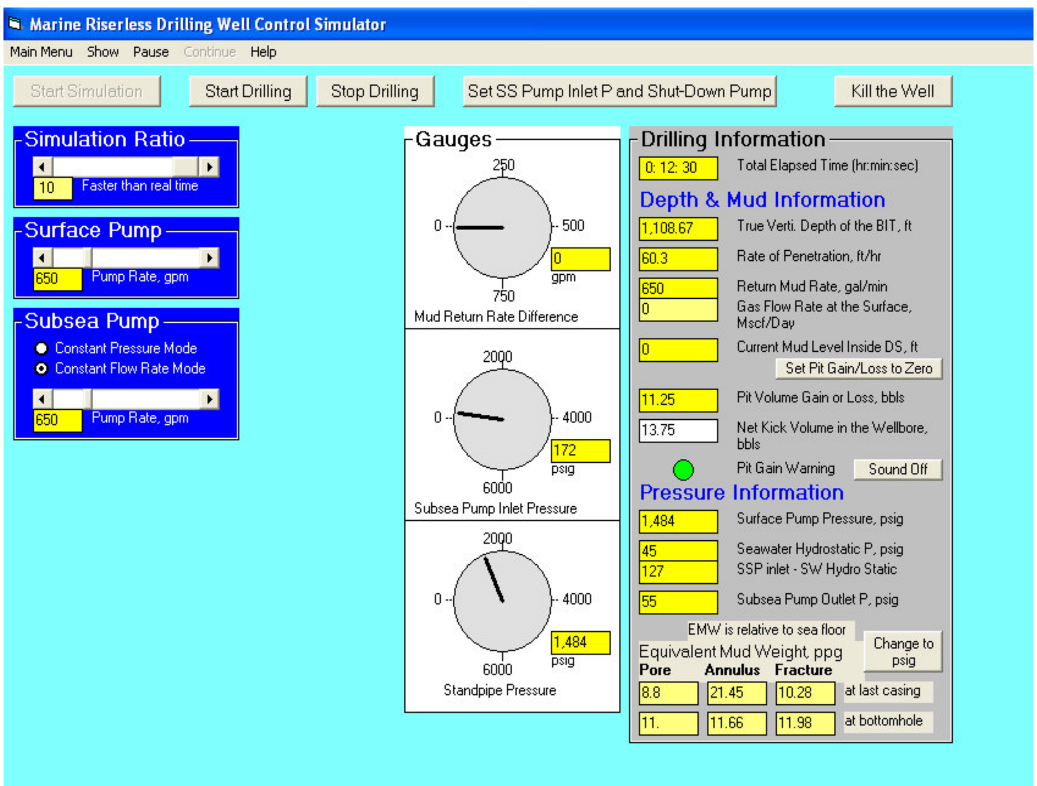


Fig. 8—Start Drilling. After following steps 1 to 7, the bottomhole pressure in the annulus has reached the bottomhole pore pressure.

9. Change the Choke Control Method to automatic, so the well control procedure is the same for every simulation, making the results more accurate.

10. Press OK **(Fig. 9).**

11. A new window will appear as seen in **Fig. 10.** Change the Simulation Acceleration Ratio to 40X faster than real time.

12. Click on the Menus dropdown, and click on Start-Circulation. The Menus dropdown also gives the option to show the wellbore to see the kick being circulated out.

13. When the kick is brought to surface, two different windows will pop up. Press OK on both windows.

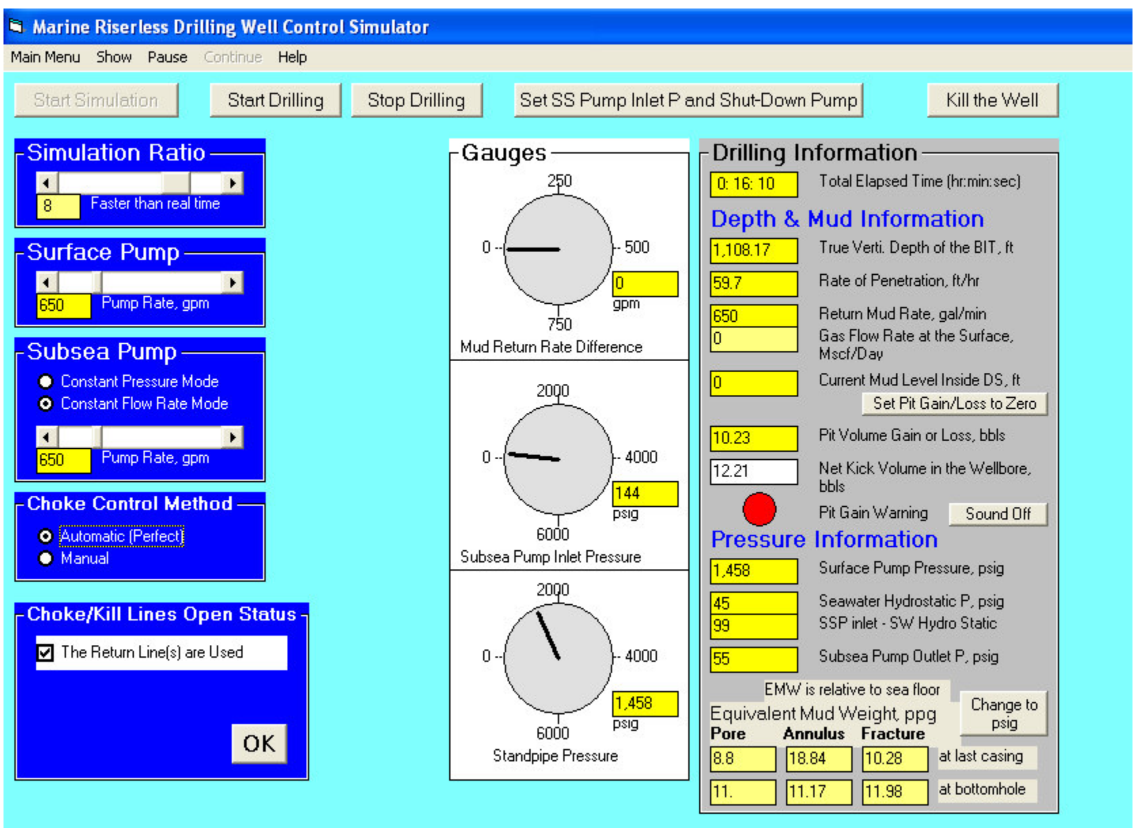


Fig. 9—Kill the Well. Steps 9 and 10-Changing the Choke Control Method to automatic will keep the well control procedures uniform for every simulation.

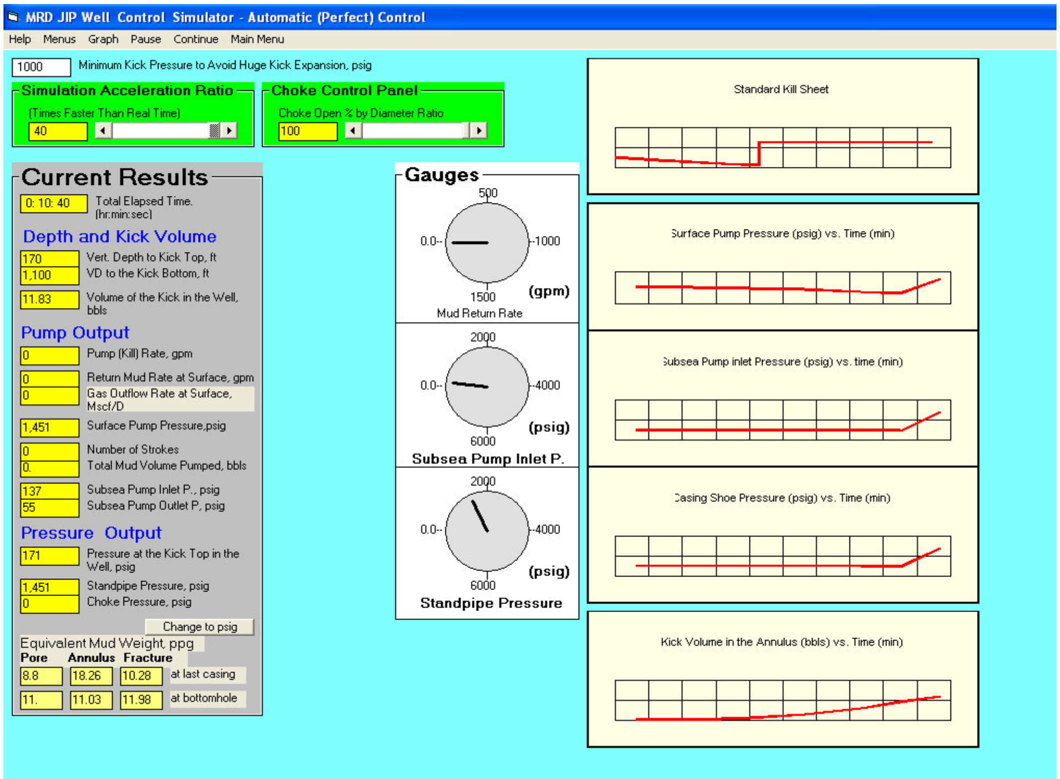


Fig. 10—Start Circulation. Steps 11 and 12-The kick is circulated out of the wellbore. The graphs and gauges show the progress.

14. Click on Main Menu.

15. Click on See Graphs (Fig. 1).

If the well blows out before the pit gain reaches the required number of barrels, the screen in **Fig. 11** will appear. This may occur on some of the simulations that have a .5 ppg formation overpressure because before the kick reaches the required number of barrels it may reach the surface causing a blowout. In this case, Procedure 2 should be followed:

1. Move the Simulation Ratio to 10X faster than real time.

2. Change the Surface Pump to 650 gpm.

3. Click Start Simulation.

4. Allow the drillstring to fill up with mud. The Subsea Pump will move to 650 gpm.

5. Click Set Pit Gain/Loss to Zero and Start Drilling.

6. Only drill 2 ft and click Stop Drilling and move the Surface Pump to 0 gpm.

7. When the Pit Gain Warning goes off, click Constant Flow Rate Mode and move the Subsea Pump to 0 gpm.

8. Steps 7 to 15 from the previous procedure can now be followed.

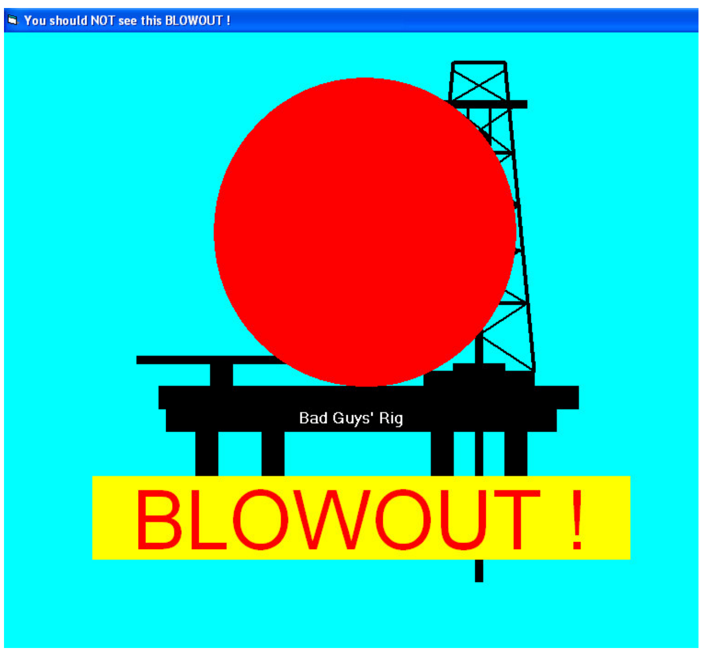


Fig. 11—Bad Guys' Rig. If a blowout occurs before the pit gain warning goes off, the procedure will need to be changed.

The simulator automatically makes graphs when the kick is being simulated. For this project, I will be exporting the data into Excel and creating graphs of time vs. influx rate and time vs. kick height. I will compare these graphs of wells with a pilot hole and without a pilot hole for shallow and deep water.

Simulation

The following data tables include the data that was changed in the simulations. For simplification purposes, two diagrams **(Fig. 12-13)** to see how the simulations were split up into the different runs. I also included four different tables **(Tables 1-4)** to split shallow/deep water and with/without a pilot hole.

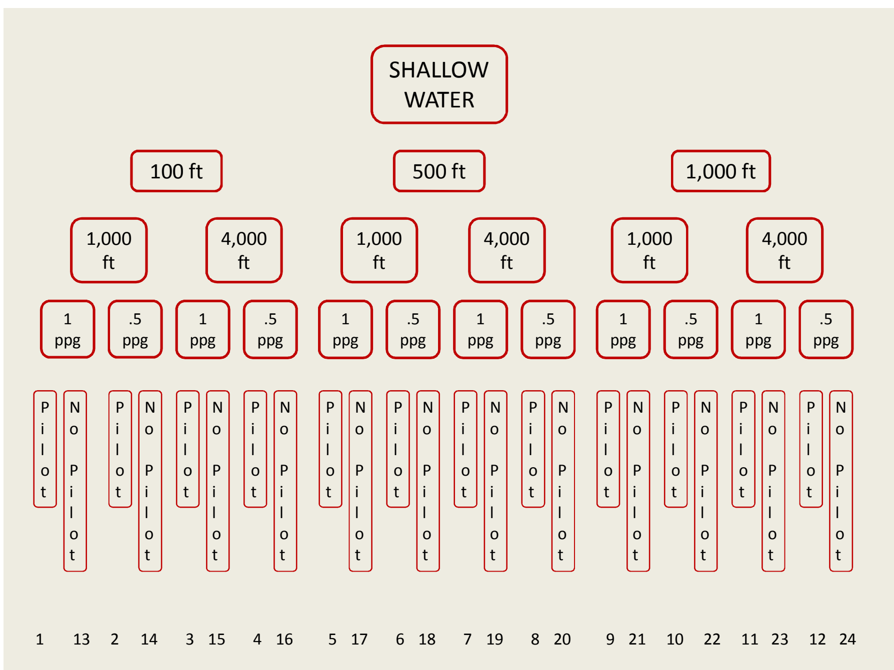


Fig. 12—Shallow Water Diagram. The shallow water simulations are first split into water depth, then casing setting depth, kick intensity, and whether or not there is a pilot hole.

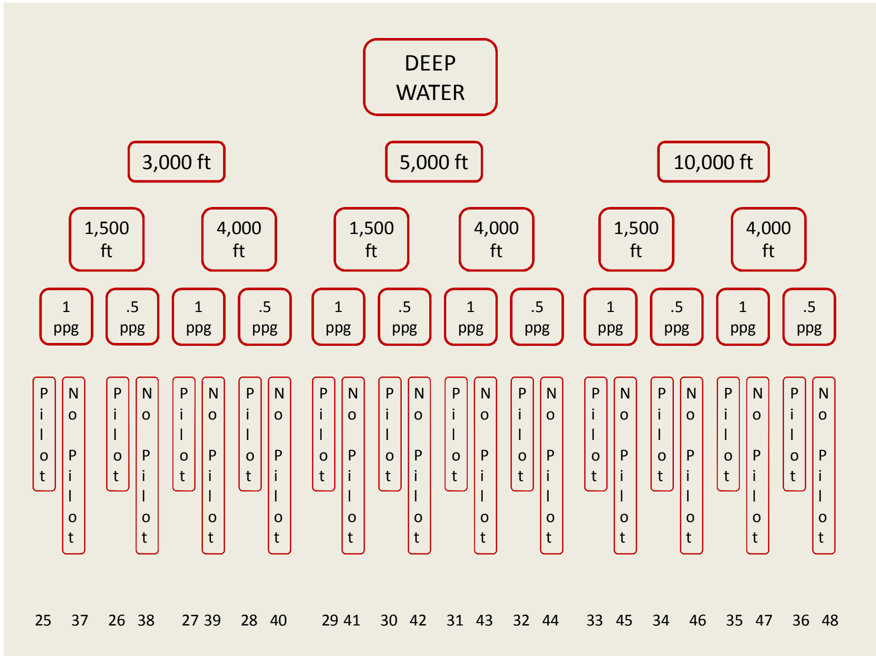


Fig. 13—Deep Water Diagram. The deep water simulations are first split into water depth, then casing setting depth, kick intensity, and whether or not there is a pilot hole.

The first six sets are shallow water wells with water depths of 100 ft, 500 ft, and 1,000 ft. The last six sets are deep water wells with water depth of 3,000 ft, 5,000 ft, and 10,000 ft. The depth of the last casing seat was included for wellbore geometry purposes. Mud weight (MW) varied between 10 ppg and 13 ppg depending on the depth of the hole below mudline (BML). I used formation overpressures of 1 ppg and .5 ppg to simulate the effect of different kick sizes on influx rate and kick height. All of the shallow water wells had a pit gain warning level of 10 bbl. The deep water wells required a pit gain warning level of 20 bbl. The highlighted runs required the second simulation procedure discussed previously. A formation overpressure of .5 ppg caused the kick to reach the surface before the entire kick could enter the wellbore.

Figs. 14-17 are the wellbore diagrams that represent the twelve sets. The red dotted lines represent the simulations that were done without a pilot hole. The hole sizes of the red dotted lines are also the sizes that are required to set the casing. The blue dotted lines represent the 12 ¼ in. pilot hole.

Table 1—Shallow Water Wells with a Pilot Hole. They are the first 12 runs and are represented by the blue dotted line in Fig. 12. The highlighted runs required the second simulation procedure.

Set	Run	Water Depth	Depth of Last Csg Seat	Old MW	600	300	Depth of 12 1/4" Pilot Hole BML	Formation Overpressure	Pit Gain Warning Level
		ft	ft, BML	ppg	rpm	rpm	ft	ppg	bbl
1	1	100	200	10	111	65	1000	1	10
	2	100	200	10	111	65	1000	0.5	10
2	3	100	1000	13	111	65	4000	1	10
	4	100	1000	13	111	65	4000	0.5	10
3	5	500	200	10	111	65	1000	1	10
	6	500	200	10	111	65	1000	0.5	10
4	7	500	1000	13	111	65	4000	1	10
	8	500	1000	13	111	65	4000	0.5	10
5	9	1,000	200	10	111	65	1000	1	10
	10	1,000	200	10	111	65	1000	0.5	10
6	11	1,000	1000	13	111	65	4000	1	10
	12	1,000	1000	13	111	65	4000	0.5	10

Table 2—Shallow Water Wells without a Pilot Hole. They are represented by the red dotted line in Fig. 13. The highlighted runs required the second simulation procedure.

Set	Run	Water Depth	Depth of Last Csg Seat	Size of Last Csg	Old MW	600	300	Depth of Hole BML	Size of Hole BML	Formation Overpressure	Pit Gain Warning Level
		ft	ft, BML	OD, in	ppg	rpm	rpm	ft	in	ppg	bbl
1	13	100	200	20	10	111	65	1000	22	1	10
	14	100	200	20	10	111	65	1000	22	0.5	10
2	15	100	1000	16	13	111	65	4000	15.5	1	10
	16	100	1000	16	13	111	65	4000	15.5	0.5	10
3	17	500	200	20	10	111	65	1000	22	1	10
	18	500	200	20	10	111	65	1000	22	0.5	10
4	19	500	1000	16	13	111	65	4000	15.5	1	10
	20	500	1000	16	13	111	65	4000	15.5	0.5	10
5	21	1,000	200	20	10	111	65	1000	22	1	10
	22	1,000	200	20	10	111	65	1000	22	0.5	10
6	23	1,000	1000	16	13	111	65	4000	15.5	1	10
	24	1,000	1000	16	13	111	65	4000	15.5	0.5	10

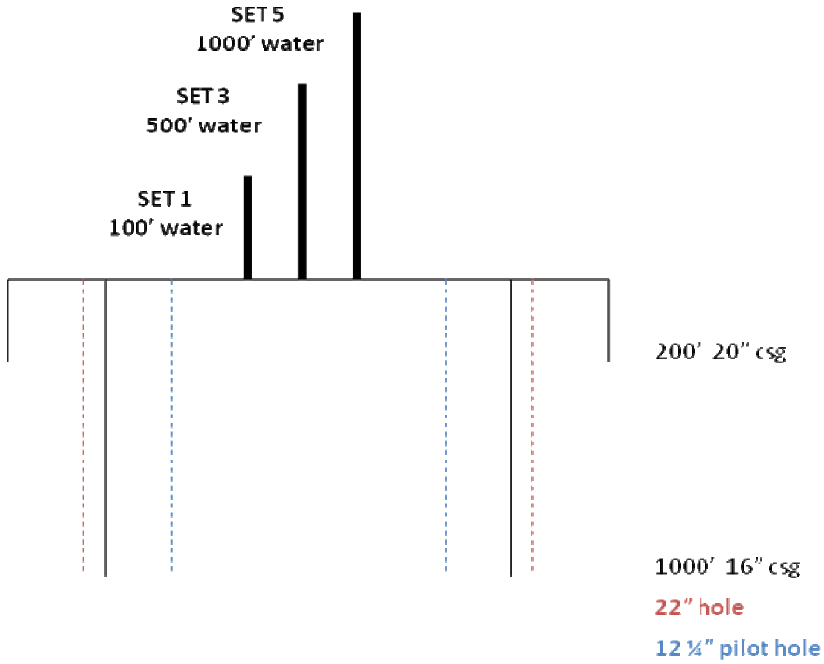


Fig. 14—Sets 1, 3, and 5 Diagram. This represents wells drilled in shallow water to a depth of 1000 ft BML where 16 in. casing will be set. The red dotted line represents the wellbore without a pilot hole, and the blue dotted line represents the wellbore with a pilot hole.

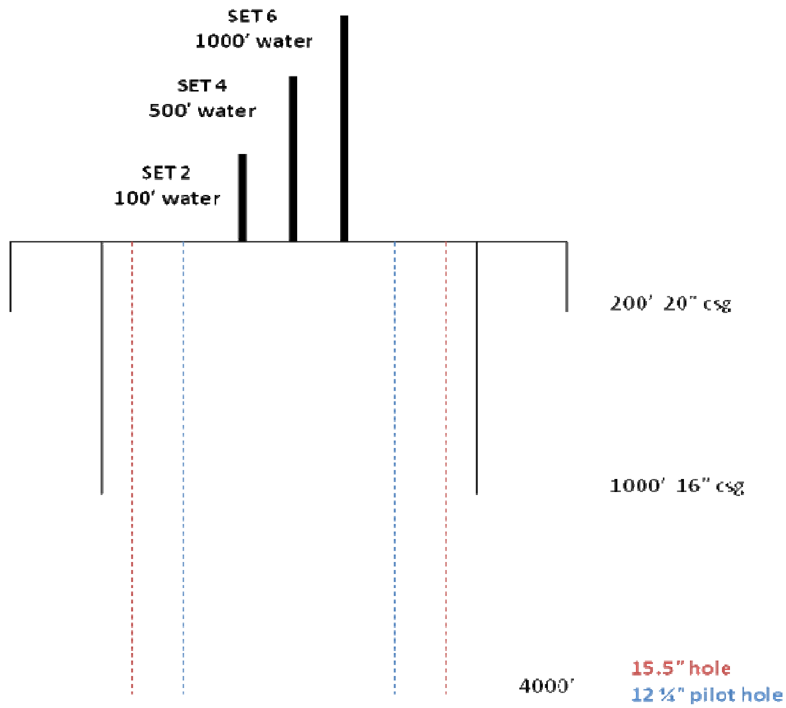


Fig. 15—Sets 2, 4, and 6 Diagram. This represents wells drilled in shallow water to a depth of 4000 ft BML. The red dotted line represents a wellbore without a pilot hole, and the blue dotted line represents a wellbore with a pilot hole.

Table 3—Deep Water Wells with a Pilot Hole. These are represented in Fig. 14. The highlighted runs required the second simulation procedure.

Set	Run	Water Depth	Depth of Last Csg Seat	Old MW	600	300	Depth of 12 1/4" Pilot Hole BML	Formation Overpressure	Pit Gain Warning Level
		ft	ft, BML	ppg	rpm	rpm	ft	ppg	bbl
7	25	3000	300	10	111	65	1500	1	20
	26	3000	300	10	111	65	1500	0.5	20
8	27	3000	1500	13	111	65	4000	1	20
	28	3000	1500	13	111	65	4000	0.5	20
9	29	5000	300	10	111	65	1500	1	20
	30	5000	300	10	111	65	1500	0.5	20
10	31	5000	1500	13	111	65	4000	1	20
	32	5000	1500	13	111	65	4000	0.5	20
11	33	10,000	300	10	111	65	1500	1	20
	34	10,000	300	10	111	65	1500	0.5	20
12	35	10,000	1500	13	111	65	4000	1	20
	36	10,000	1500	13	111	65	4000	0.5	20

Table 4—Deep Water Wells without a Pilot Hole. These are represented in Fig. 15. The highlighted runs required the second simulation procedure.

Set	Run	Water Depth	Depth of Last Csg Seat	Size of Last Csg	Old MW	600	300	Depth of Hole BML	Size of Hole BML	Formation Overpressure	Pit Gain Warning Level
		ft	ft, BML	OD, in	ppg	rpm	rpm	ft	in	ppg	bbl
7	37	3000	300	30	10	111	65	1500	30	1	20
	38	3000	300	30	10	111	65	1500	30	0.5	20
8	39	3000	1500	26	13	111	65	4000	24	1	20
	40	3000	1500	26	13	111	65	4000	24	0.5	20
9	41	5000	300	30	10	111	65	1500	30	1	20
	42	5000	300	30	10	111	65	1500	30	0.5	20
10	43	5000	1500	26	13	111	65	4000	24	1	20
	44	5000	1500	26	13	111	65	4000	24	0.5	20
11	45	10,000	300	30	10	111	65	1500	30	1	20
	46	10,000	300	30	10	111	65	1500	30	0.5	20
12	47	10,000	1500	26	13	111	65	4000	24	1	20
	48	10,000	1500	26	13	111	65	4000	24	0.5	20

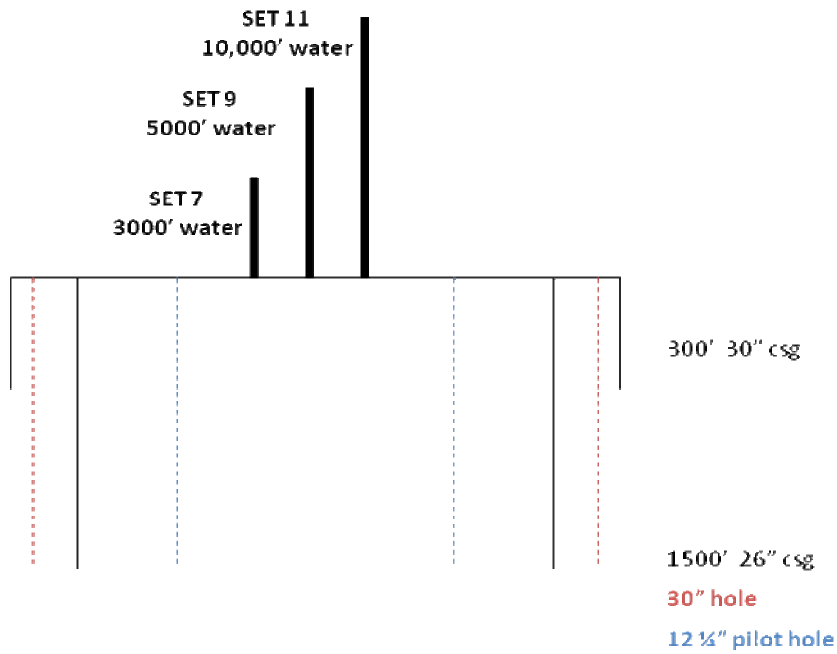


Fig. 16—Sets 7, 9, and 11 Diagram. This represents wells drilled in deep water to 1500 ft BML where 26 in. casing will be set. The red dotted line represents a well without a pilot hole, and the blue dotted line represents a well with a pilot hole.

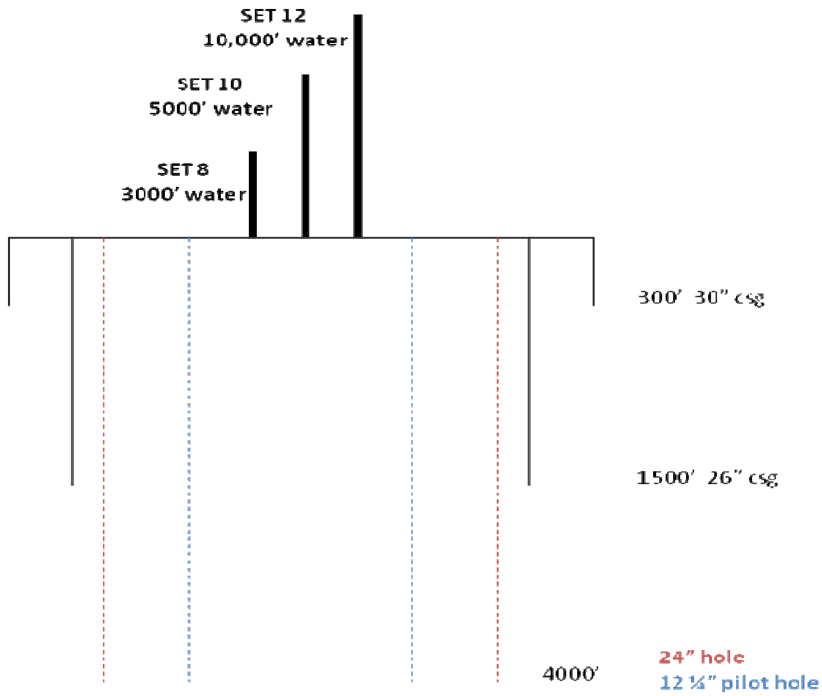


Fig. 17—Sets 8, 10, and 12 Diagram. This represents wells drilled in deep water to a depth of 4000 ft BML. The red dotted line represents a well without a pilot hole, and the blue dotted line represents a well with a pilot hole.

Results

I created twelve sets of graphs with the output data from the simulator. The first six sets are the shallow water simulations, and the last six are the deep water simulations. Influx rates and kick heights of 1 ppg and .5 ppg overpressures are included in each set. Trends are clearly evident by simulation procedure and amount of formation overpressure, which will be discussed in the following paragraphs.

First, the results from Procedure 2 will be discussed. A graph of Set 3 is shown below. The other 3 graphs from Procedure 2 follow the same patterns.

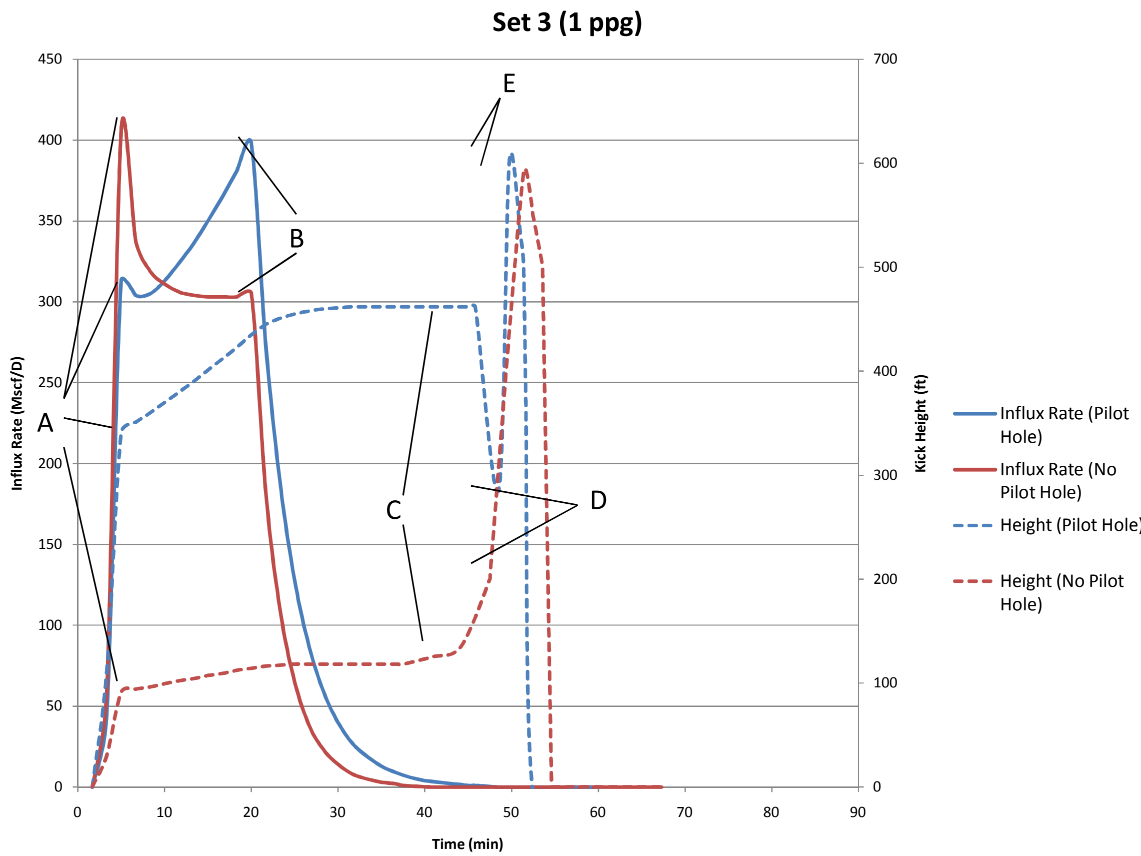


Fig. 18—Set 3 (1 ppg). This graph represents the simulations done by Procedure 2. All of these simulations follow the same trend.

Shown in **Fig. 18,** at A, the influx rate has an initial spike in the well without a pilot hole. There is still a lot of liquid in the system because the larger diameter hole does not allow for a large column of gas in the annulus, so there is a greater friction loss in the annulus while drilling. This increases the BHP, which slows down the influx because the drawdown decreases. In comparison, the well with a pilot hole has an increase in influx rate because the smaller hole forces the height of the gas to increase. This reduces the BHP causing the drawdown to increase, which allows more gas to enter into the wellbore. At B, drilling stops so the influx rate for both wells decreases rapidly. At C, the kick begins to enter the previous casing string. For the well with a pilot hole, the height decreases because the casing string has a larger diameter than the pilot hole. For the well without a pilot hole, the height continues to increase because the casing diameter is actually smaller than the hole size. We are assuming that a hole opener was run with the bit. This is not the case in all of the simulations. At D, the top of the kick has reached the mudline, and is about to enter the return line. E shows where the top of the kick has reached the surface, so the height begins to decrease quickly because the gas is leaving the system. The distance between the two peaks at E is the difference in reaction time.

Even though the initial influx is greater in the well without a pilot hole, the influx rate decreases rapidly. In comparison, the influx rate increases rapidly in the well with a pilot hole. As the influx enters the wellbore, the height increases rapidly. Clearly, the height of the kick is much greater in the well with a pilot hole until the kick reaches the previous casing string. The maximum height of the kick in the well with a pilot hole is 10 feet greater and reaches that point a couple of minutes faster than the maximum height of the kick in the well without a pilot hole, so the well without a pilot hole allows more reaction time.

Set 6 will represent the graphs from Procedure 1 **(Fig. 19).**

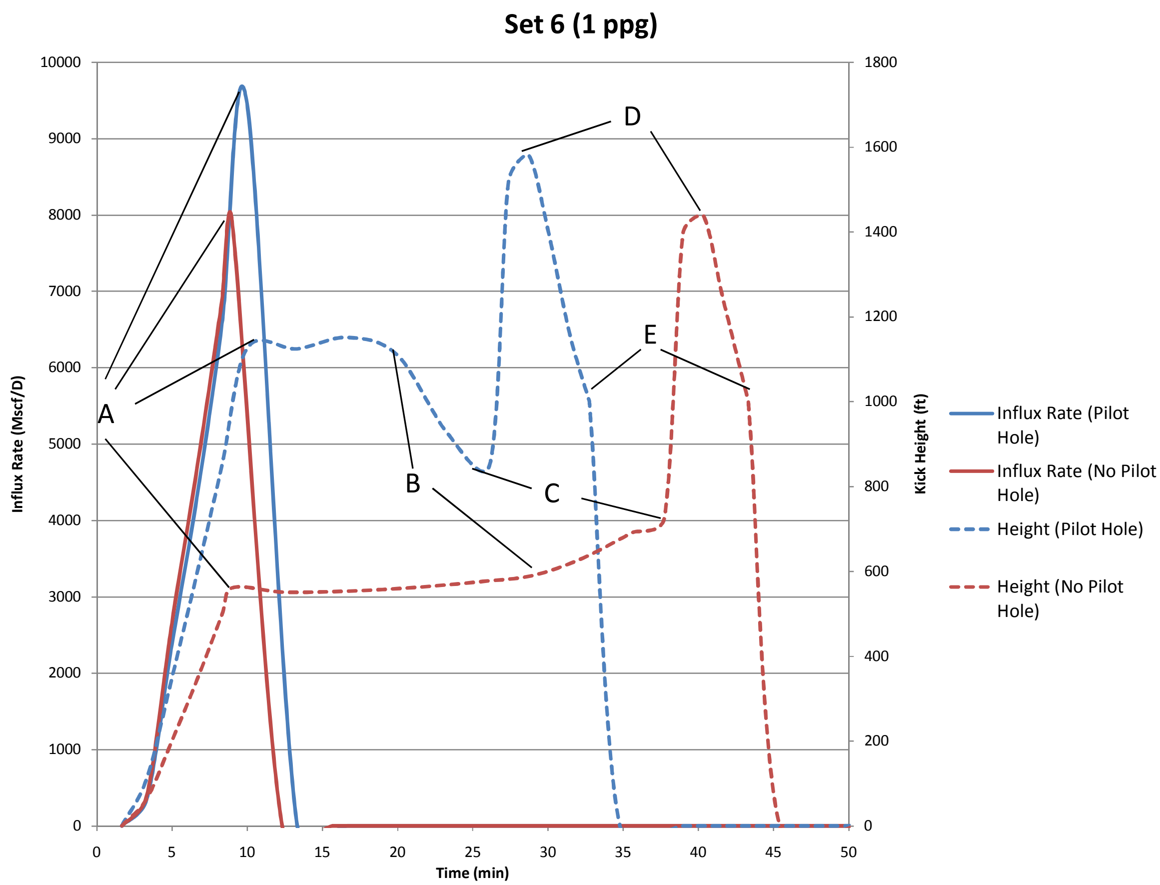


Fig. 19—Set 6 (1 ppg). This graph represents the simulations done by Procedure 1. All of these simulations follow the same trend.

The peak of both influx rate curves (A) shows when the entire influx has entered the wellbore. The influx rate is greater in the well with the pilot hole because the smaller diameter hole forces the gas column to be taller, which decreases the BHP. A smaller BHP causes the drawdown pressure to increase, allowing more gas to flow into the annulus. The influx reaches the previous casing string at B. At B, the height of the kick of the well with a pilot hole decreases because it enters a larger diameter casing string.

The height of the kick from the well without a pilot hole continues to increase because the inner diameter of the 16 in. casing is the same as the hole diameter. Point C shows where the influx reaches the mudline and enters the return line, forcing the heights of the kicks to increase drastically. The maximum height (D) is reached when the kick reaches the surface and is leaving the annulus. All of these stages of the influx occur more quickly in the well with a pilot hole. The maximum height of the kick is also greater in the well with a pilot hole.

The patterns are constant for the influx rate curves based on the simulation procedure. The height curves also follow the same trend throughout, based on the simulation procedure. When comparing kick heights between wells with a pilot hole and wells without a pilot hole, the maximum kick height was usually greater in wells with a pilot hole. Also, wells without a pilot hole do not reach maximum height until after the wells with a pilot hole.

Clearly, looking at these simulations, though the influx rate may be greater in a well without a pilot hole in a rare case, there is more reaction time in the well without a pilot hole. In many cases, the kick height is much larger throughout the simulation in a well with a pilot hole. The remaining graphs can be found in the Appendix.

When comparing the formation overpressure of 1 ppg to .5 ppg, there were not many differences. As seen in **Fig. 20**, the Procedure 2 simulations produced very similar graphs. One major difference is that the influx rates were lower overall. Also, the initial spike of the influx rate of the well without a pilot hole is not as large because there is a smaller amount of gas entering the wellbore. The spike of the influx rate of the well with a pilot hole is quite a bit larger with a .5 ppg overpressure because it takes longer for the kick to reach 10 bbl in the this case. This is also why it takes longer for the kick to reach its maximum height. There is a distinct difference in how much more reaction time the well without a pilot hole has with a .5 ppg overpressure compared to a 1 ppg overpressure.

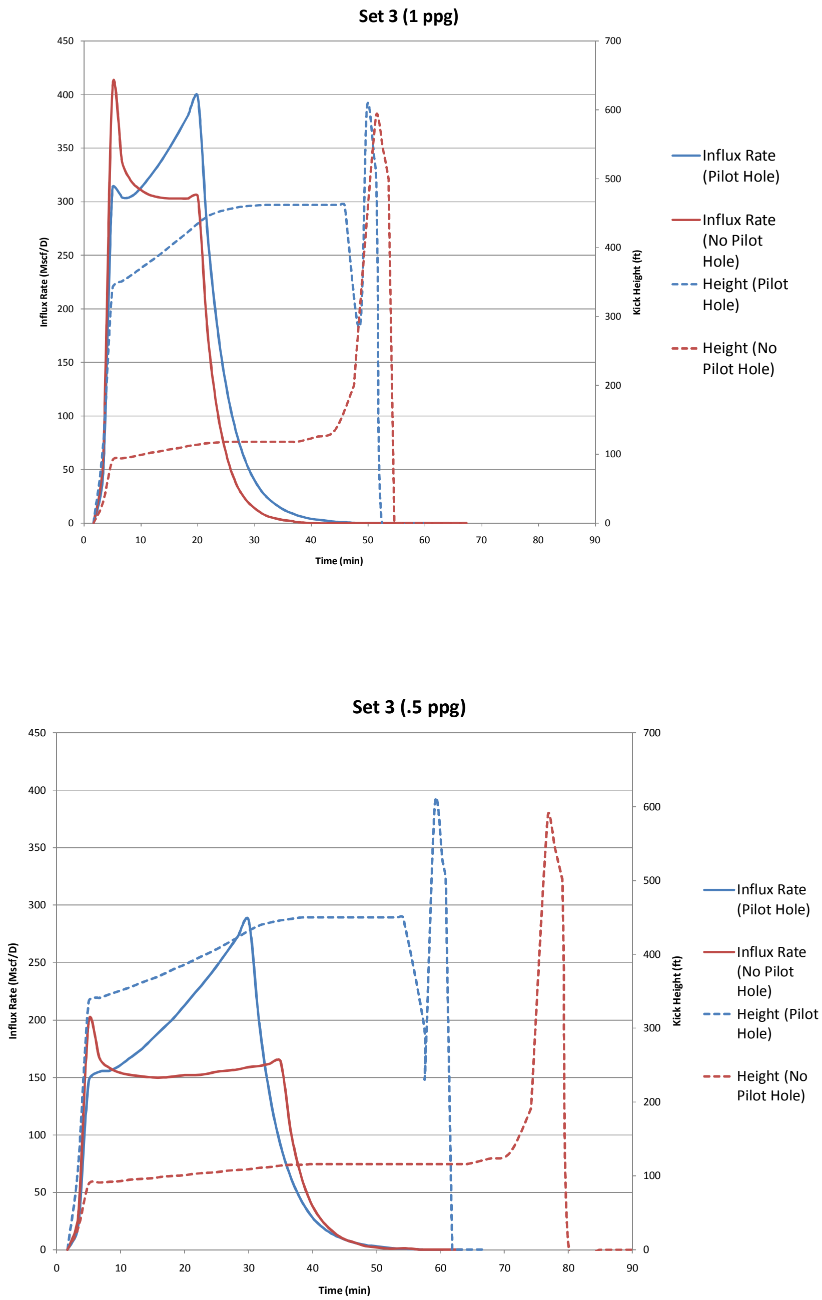
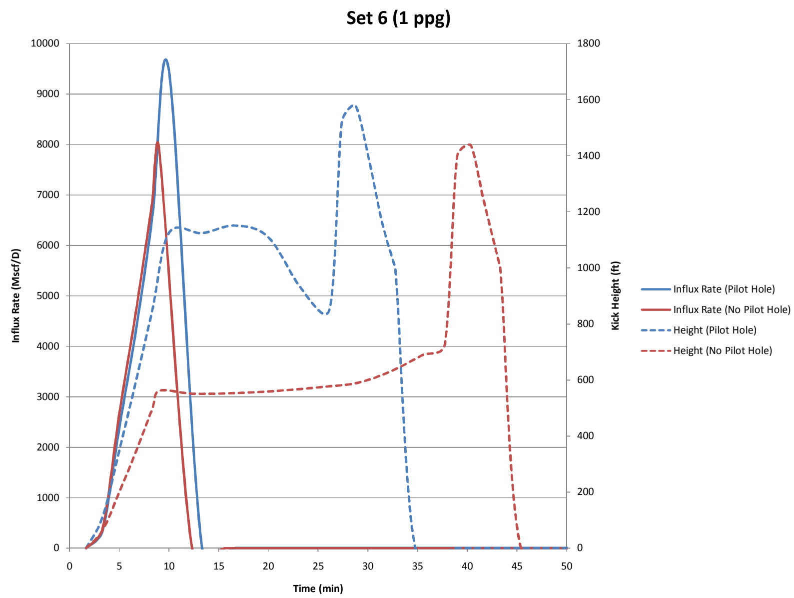


Fig. 20—Comparison of Set 3. Both Set 3 graphs show that the 1 ppg overpressure and .5 ppg overpressure simulations create similar trends in influx rate and kick height. This is representative of the other simulations done by Procedure 2.

The graphs in **Fig. 21** show that the Procedure 1 simulations also produced very similar graphs. The two major differences between the 1 ppg formation overpressure and the .5 ppg overpressure is that the influx rates from the wells with 1 ppg overpressure is quite a bit larger than the wells with the .5 ppg overpressure, and the kick heights from the wells with 1 ppg overpressure are smaller than the wells with the .5 ppg overpressure. As discussed previously, the .5 ppg overpressure takes longer to build up to a 10 bbl kick, so the kick has more time to travel up the wellbore and create a larger column of gas. The difference in reaction time between the wells in each graph does not change.



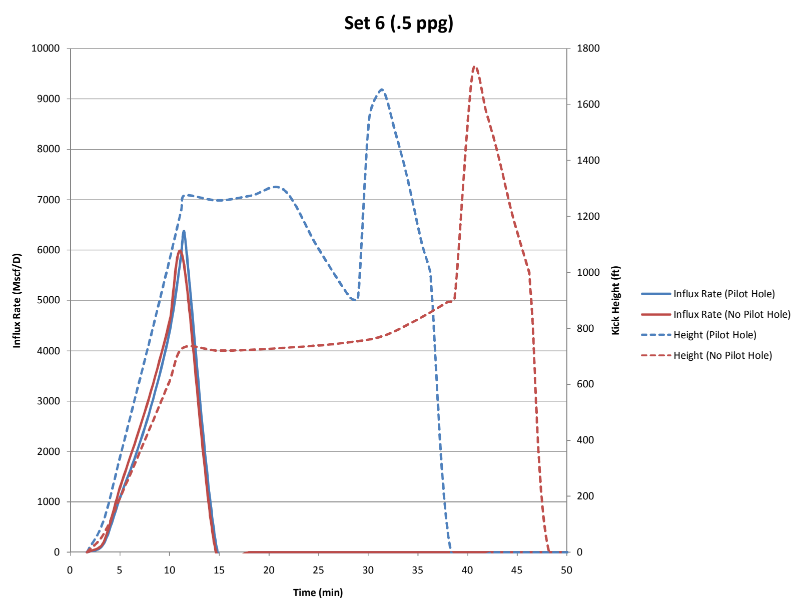


Fig. 21—Comparison of Set 6. These Set 6 graphs are representative of the other simulations done by Procedure 1. The trends are similar between the 1 ppg overpressure and .5 ppg overpressure.

CHAPTER IV

CONCLUSION AND RECOMMENDATIONS

Conclusion

Clearly, the ability to prevent blowouts is greatly needed and desired by the oil industry. The potential that kicks have to cause a blowout makes it important to learn how to control them and prevent them from occurring. Two procedures allowed the ability to simulate kicks and control them. Procedure 1 simulated continuous drilling as the kick entered the wellbore until the pit volume gain reached the required number of barrels. Procedure 2 simulated a kick entering the wellbore until it reached the required number of barrels when drilling only 2 feet. Procedure 2 needed to be used for some simulations that had a .5 ppg formation overpressure because the kick needed more time to reach the full volume before reaching the surface. DGD technology has opened up new possibilities for our industry, and Dr. Choe's Top Hole Dual Gradient Simulator has allowed us to investigate some of these possibilities with two procedures. This project has shown that with the use of tophole dual gradient drilling:

1. Kick heights are smaller with a larger diameter hole than with a pilot hole until the kick reaches the previous casing string.
2. In Procedure 2, the influx rate from the well with the larger hole diameter is initially greater than the influx rate from the well with the pilot hole.
3. In Procedure 2, there is more reaction time in the well with the larger diameter.

4. In Procedure 1, the influx rate from the well with the pilot hole is greater than the influx rate from the well with the larger hole diameter.
5. In Procedure 1, there is more reaction time in the well with the larger diameter, and the difference in reaction times is greater than the difference in reaction times in Procedure 2.
6. The wells with 1 ppg and .5 ppg formation overpressure follow the same trends.
7. The wells with a .5 ppg formation overpressure have smaller influx rates.
8. The wells with a .5 ppg formation overpressure have smaller kick heights.
9. The wells with a .5 ppg formation overpressure show a greater difference in how much more reaction time a well with a larger hole diameter has.

Recommendations

The results of this project have shown that with the use of DGD, the pilot hole can be eliminated when drilling through shallow gas zones. The elimination of the pilot hole can save time and money. Though dual gradient tophole drilling technology has been simulated, steps should be taken to drill real wells and get real results. This would further the industry's knowledge about a safer and more time efficient way of drilling offshore.

REFERENCES

Choe, J. and Juvkam-Wold, H.C. Conoco & Hydril MRD JIP Riserless Drilling Simulator, November 30, 1999 Version. 1999.

Bourgoyne, A. T., Millheim, K. K., Chenevert, M. E., and Young F.S. 1986. *Applied Drilling Engineering*, SPE Textbook Series, Richardson, Texas, **2**: 22.

Elieff, B.:2006. Top Hole Drilling with Dual Gradient Technology to Control Shallow Hazards. Thesis. Texas A&M University, College Station, TX.

Goins, W.C. Jr. and Ables G.L. The Causes of Shallow Gas Kicks. Paper SPE 16128 presented at the 1987 SPE/IADC Drilling Conference, New Orleans, Louisiana, 15-18 March. SPE-16128-MS DOI: 10.2118/16128-MS

Holand, P. 1997. *Offshore Blowouts: Causes and Control*. Houston, Texas: Gulf Publishing Company.

Marken, C., Hansen, S., and Oregaard, J. Shallow Gas Kick: Simulation and Analysis for Top Hole Drilling Without a Riser. Paper SPE 63197 presented at the 2000 Annual Technical Conference and Exhibition, Dallas, Texas, 1-4 October. SPE-63197-MS DOI: 10.2118/63197-MS

Sandlin, C.W. Drilling Safely Offshore in Shallow Gas Areas. Paper SPE 15897 presented at the 1986 SPE European Petroleum Conference, London, England, 20-22 October. SPE-15897-MS DOI: 10.2118/15897-MS

Schubert, J.J., Juvkam-Wold, H.C., and Choe, J. Well Control Procedures for Dual Gradient Drilling as Compared to Conventional Riser Drilling. Paper SPE 79880 presented at the 2003 SPE/IADC Drilling Conference, Amsterdam, The Netherlands, 19-21 February. SPE-79880-MS DOI: 10.2118/79880-MS

Schubert, J., Juvkam-Wold, H.C., Weddle, C.E. III, and Alexander, C.H. HAZOP of Well Control Procedures Provides Assurance of the Safety of the SubSea MudLift Drilling System. Paper SPE 74482 presented at the 2002 IADC/SPE Drilling Conference, Dallas, Texas, 26-28 February. SPE-74482-MS DOI: 10.2118/74482-MS

Smith, K.L., Gault, A.D., Witt, D.E., and Weddle, C.E. Subsea MudLift Drilling Joint Industry Project: Delivering Dual Gradient Drilling Technology to Industry. Paper SPE 71357 presented at the 2001 SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, 30 September-3 October. SPE 71357-MS DOI: 10.2118/71357-MS

Watson, D., Brittenham, T., and Moore, P.L. 2003. *Advanced Well Control*, SPE Textbook Series, Richardson, Texas **10**: 155-165.

APPENDIX A

SIMULATION RESULTS

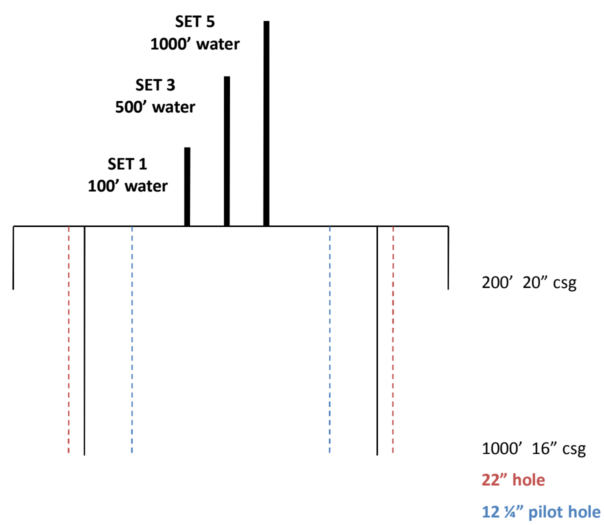


Fig. A-1—Diagram of Set 1, Set 3, and Set 5

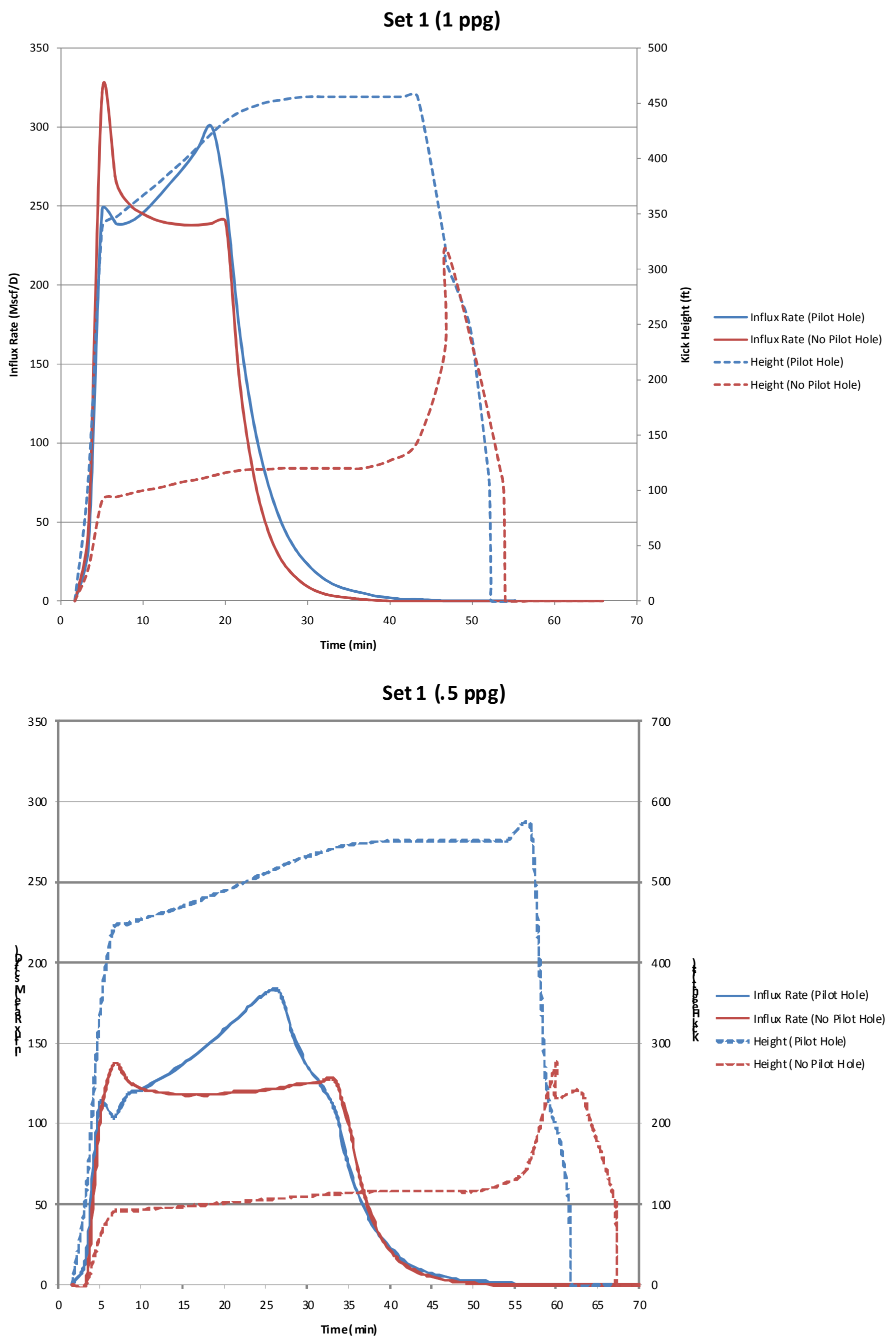


Fig. A-2—Set 1 (1 ppg) compared to Set 1 (.5 ppg)

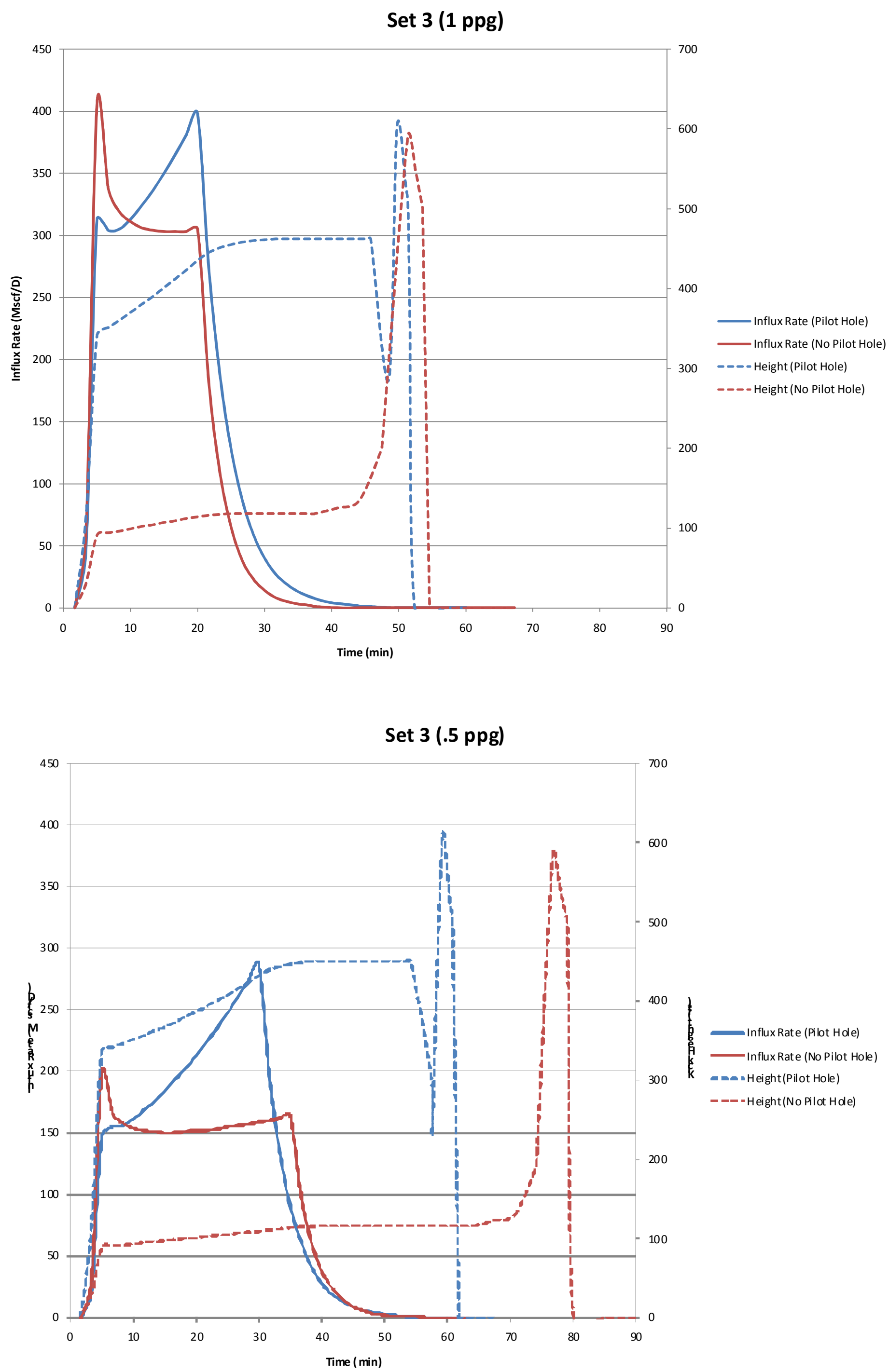
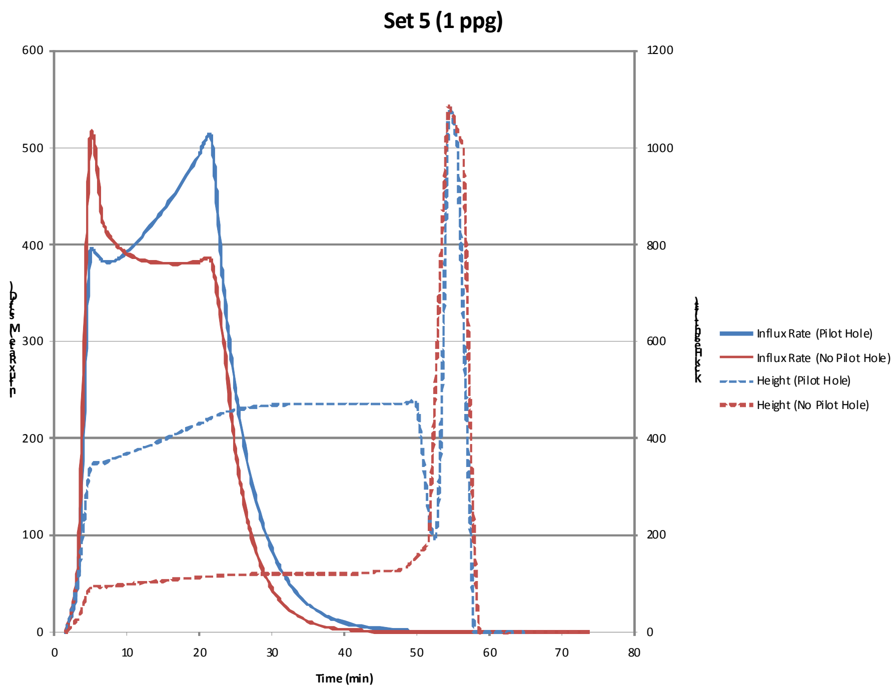


Fig. A-3—Set 3 (1 ppg) compared to Set 3 (.5 ppg)



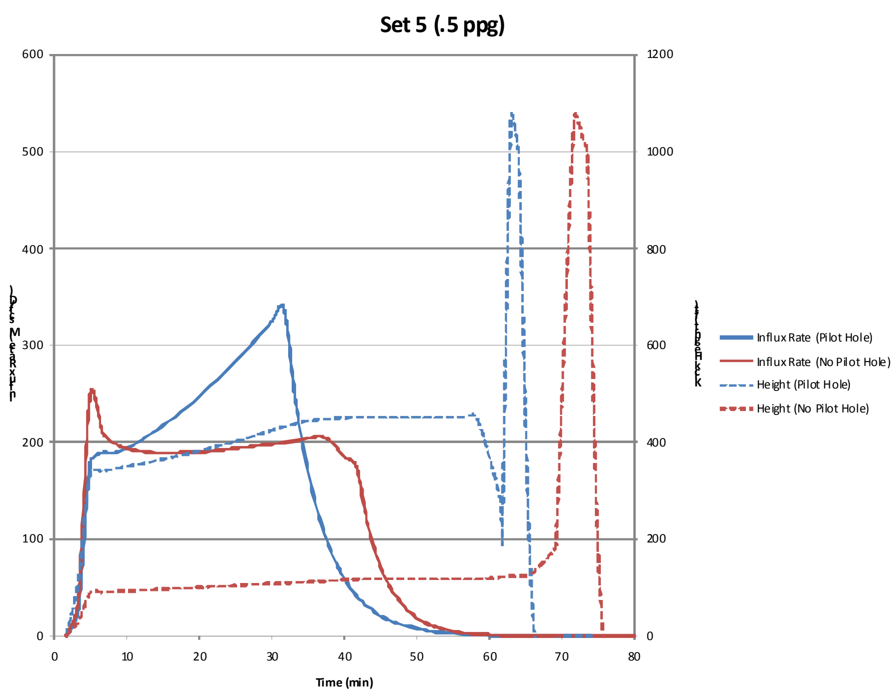


Fig. A-4—Set 5 (1 ppg) compared to Set 5 (.5 ppg)

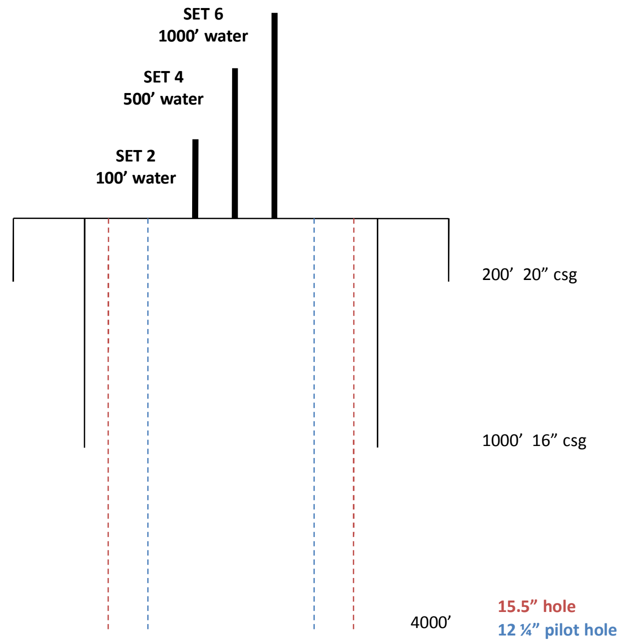


Fig. A-5—Diagram of Set 2, Set 4, and Set 6

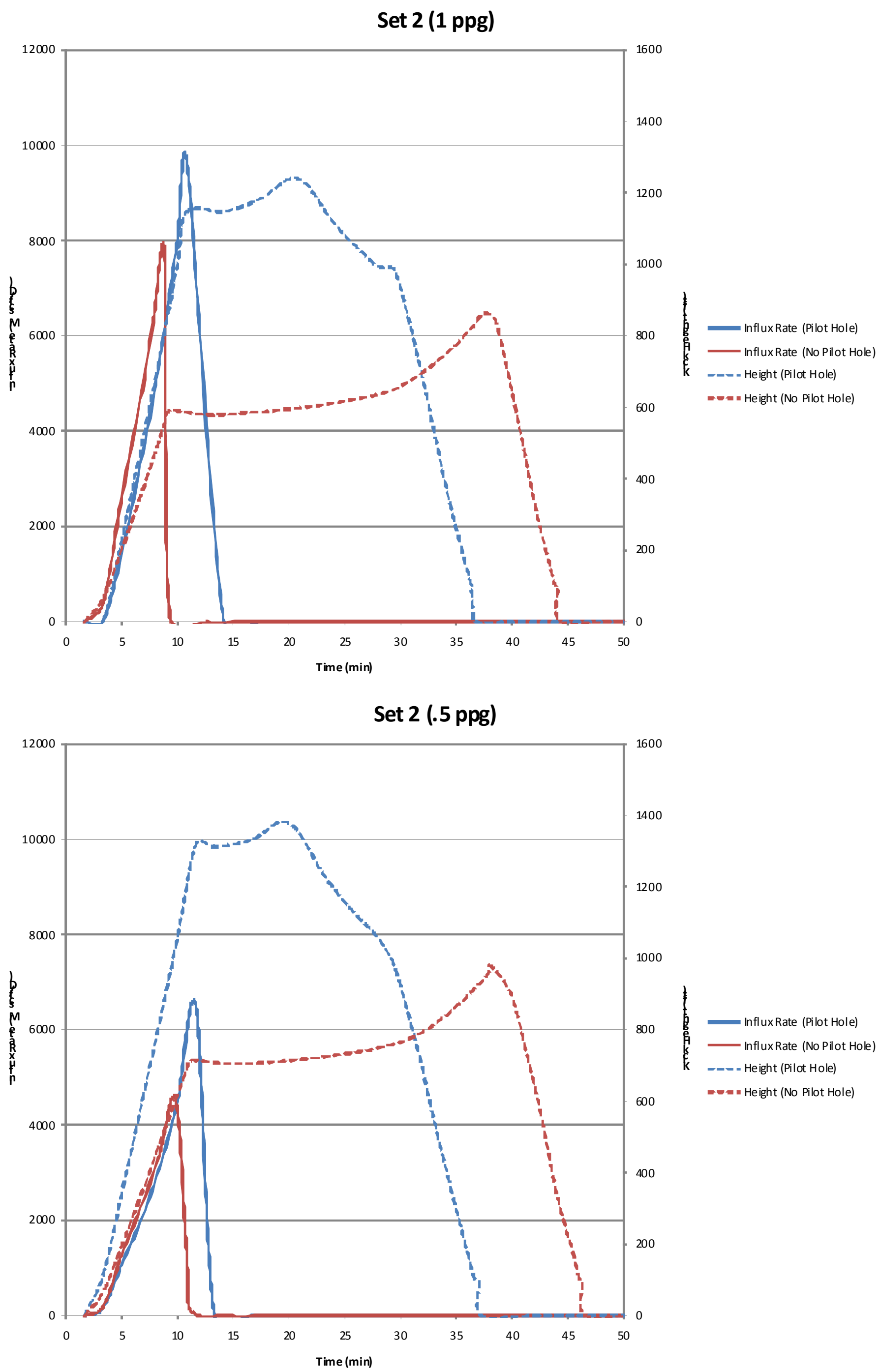
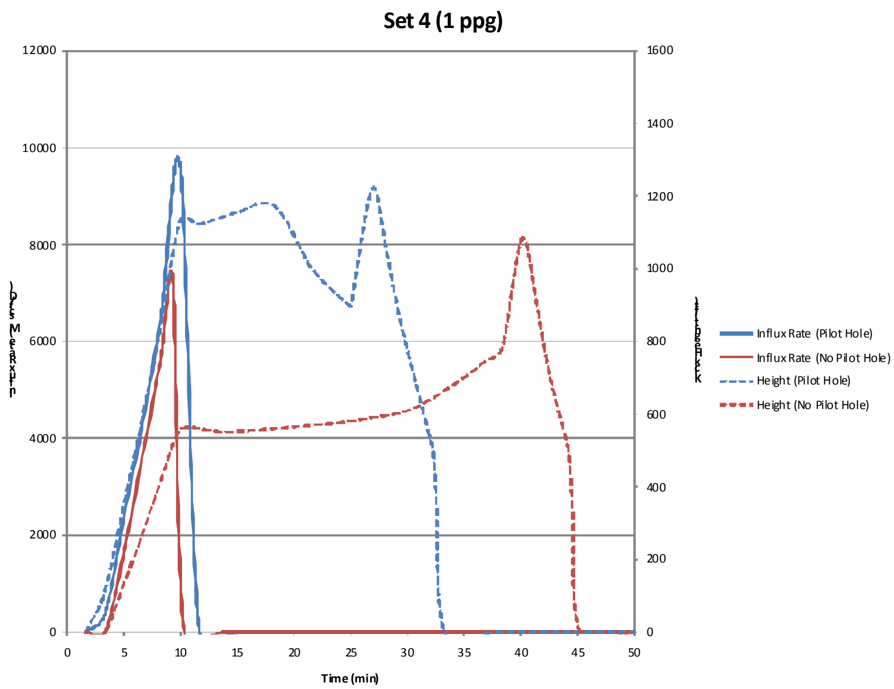


Fig. A-6—Set 2 (1 ppg) compared to Set 2 (.5 ppg)



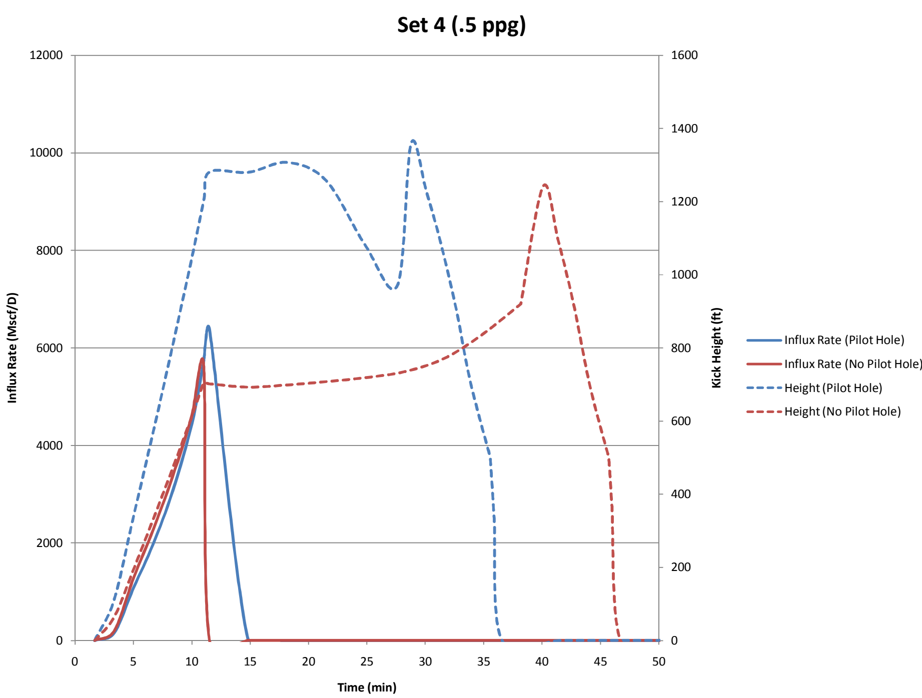


Fig. A-7—Set 4 (1 ppg) compared to Set 4 (.5 ppg)

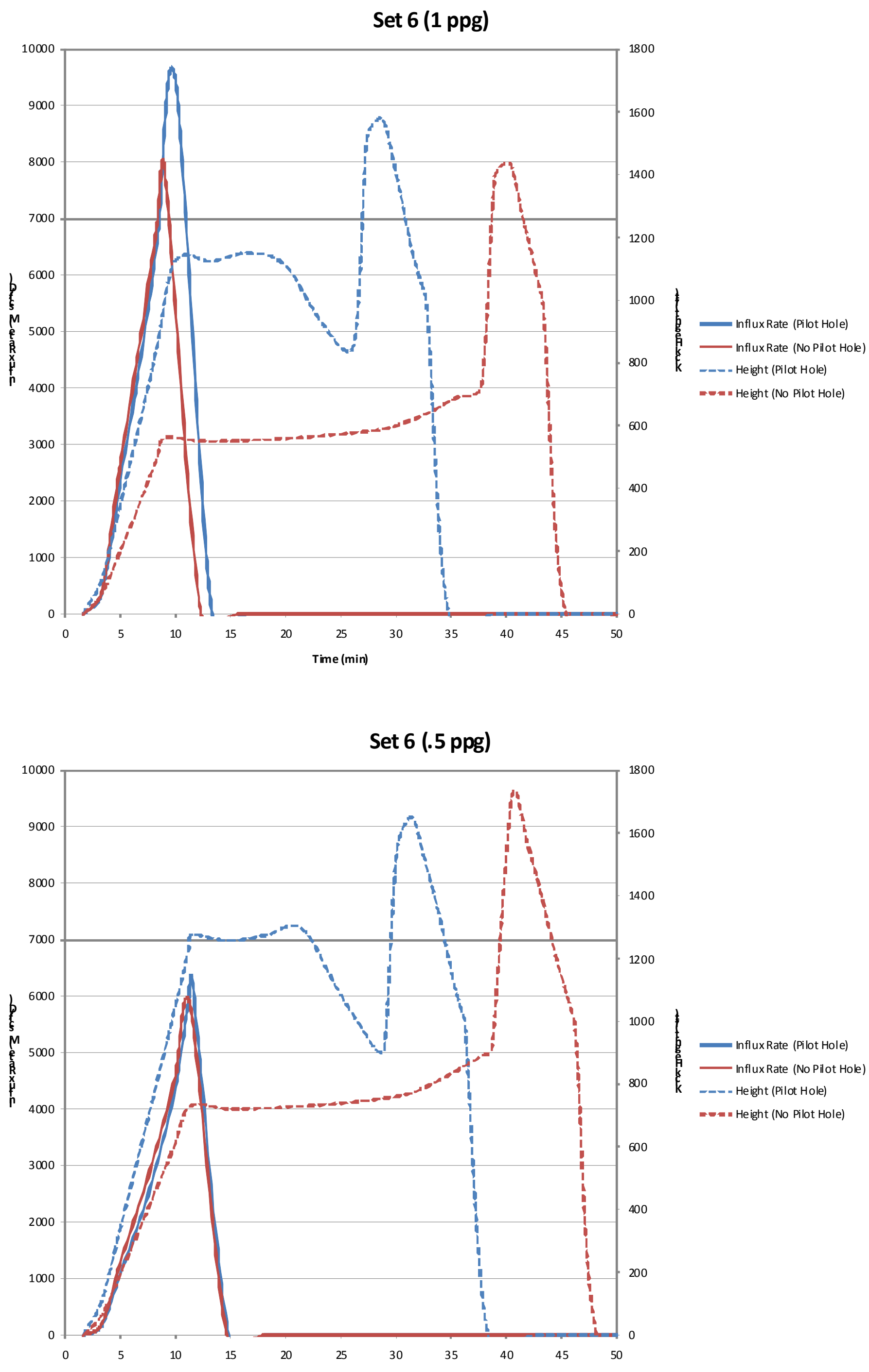


Fig. A-8—Set 6 (1 ppg) compared to Set 6 (.5 ppg)

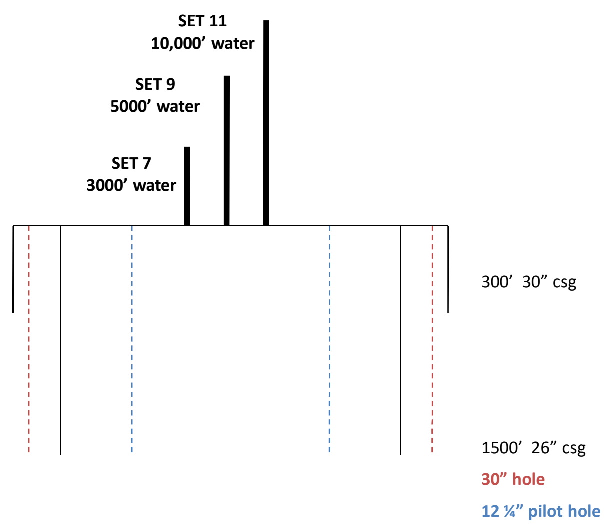


Fig. A-9—Diagram of Set 7, Set 9, and Set 11

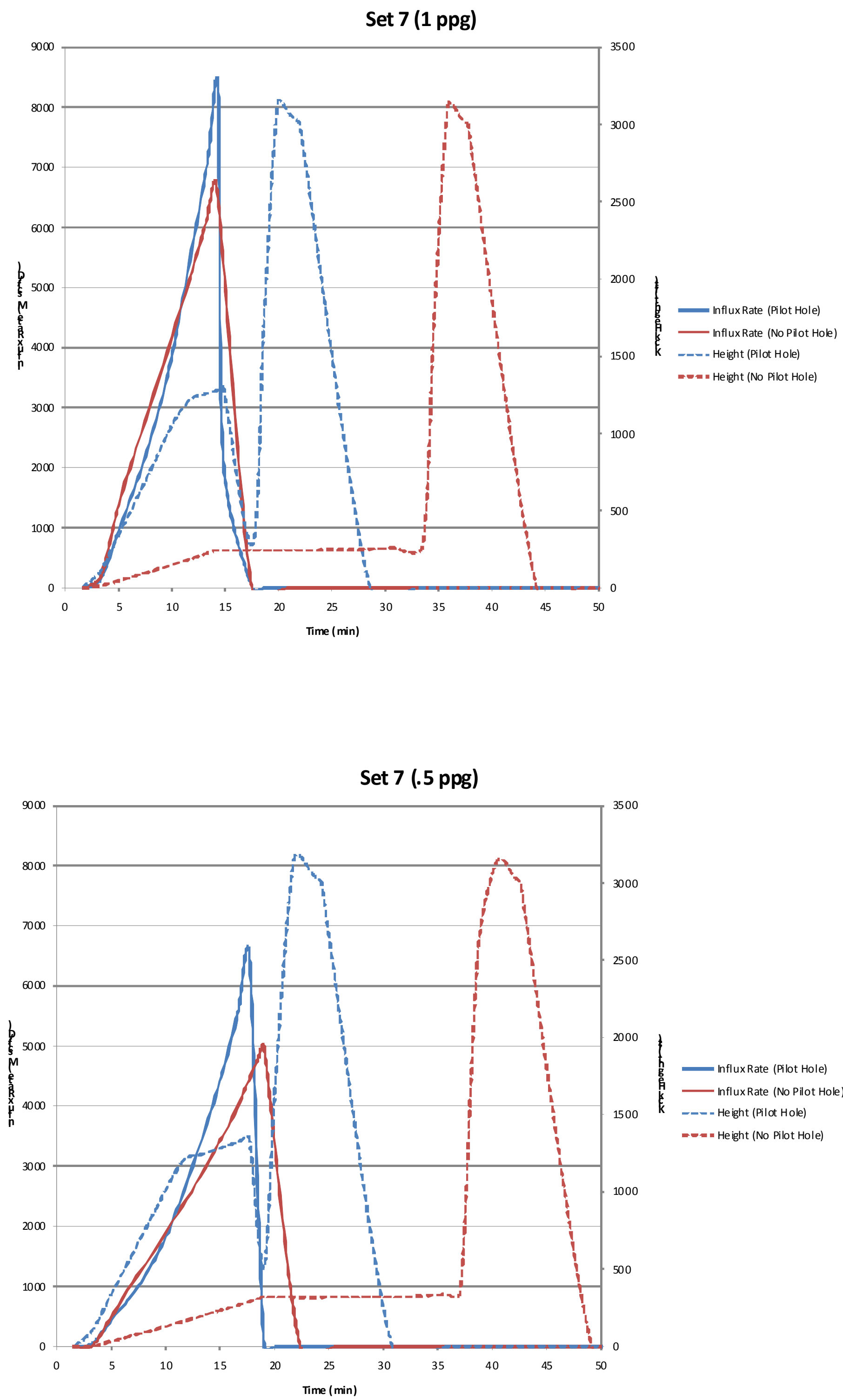
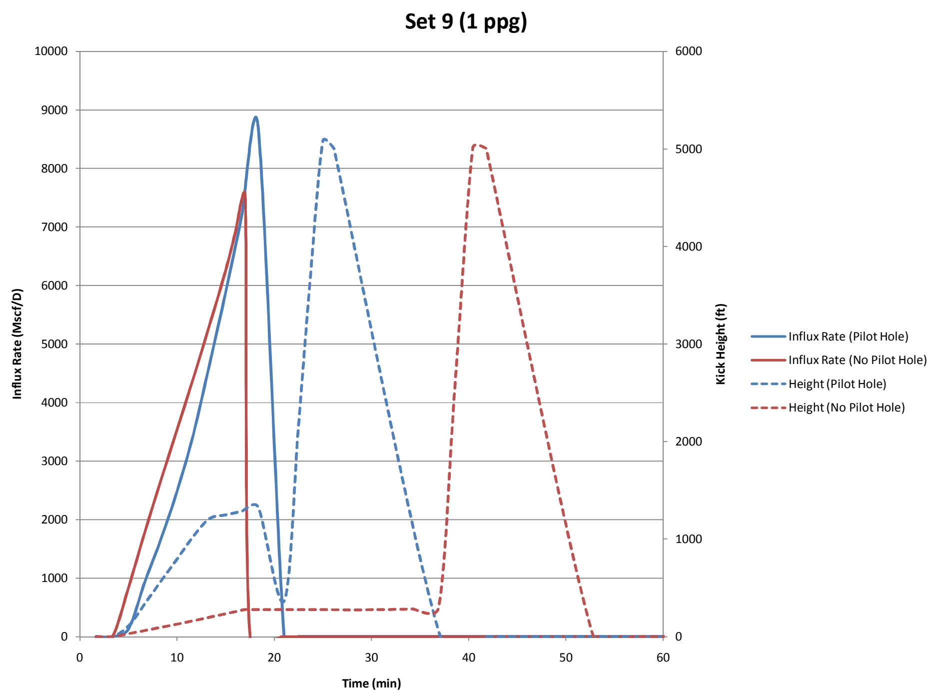


Fig. A-10—Set 7 (1 ppg) compared to Set 7 (.5 ppg)



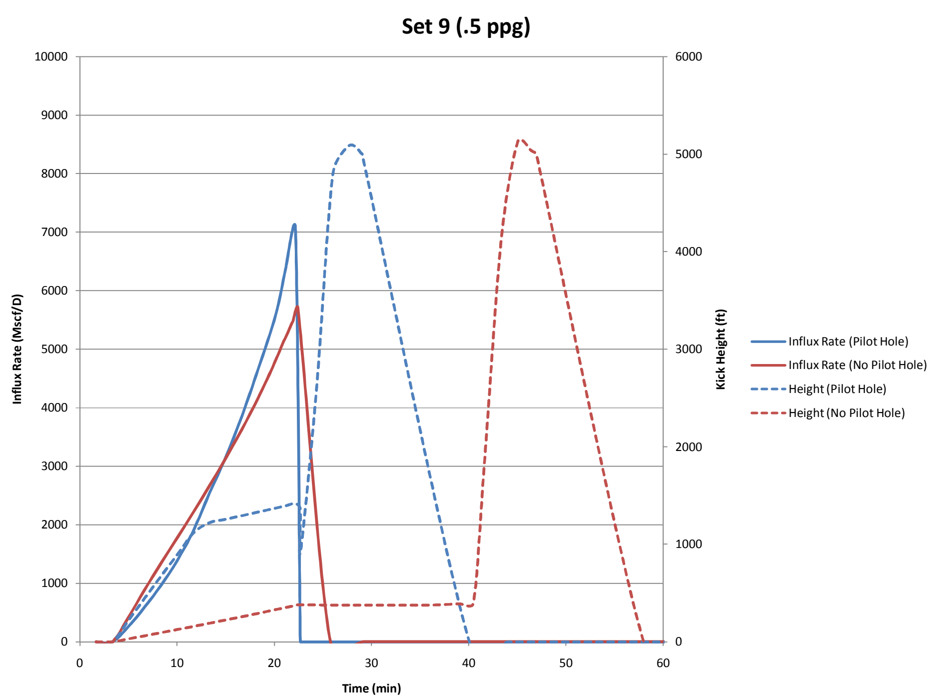
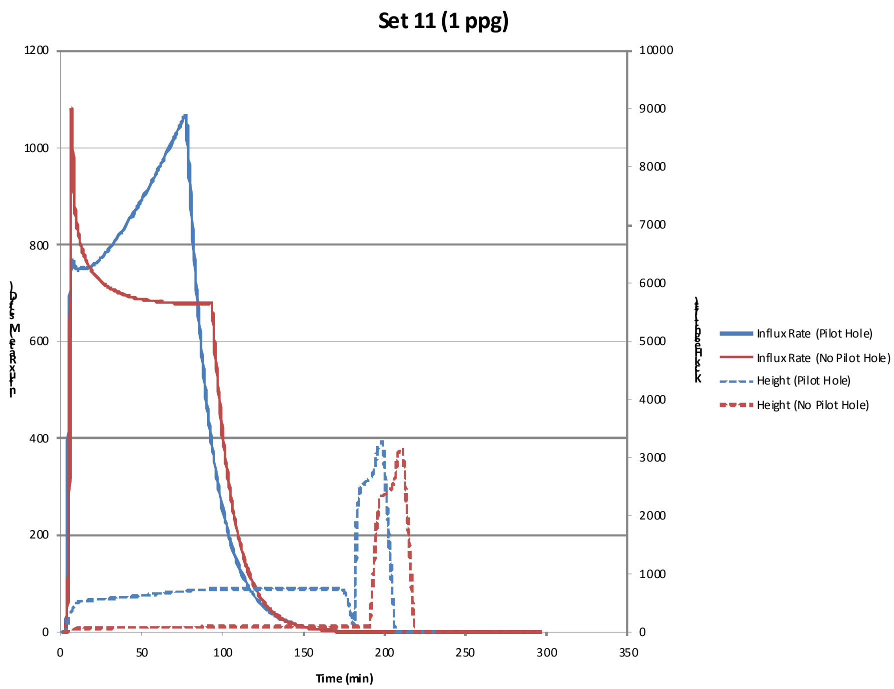


Fig. A-11—Set 9 (1 ppg) compared to Set 9 (.5 ppg)



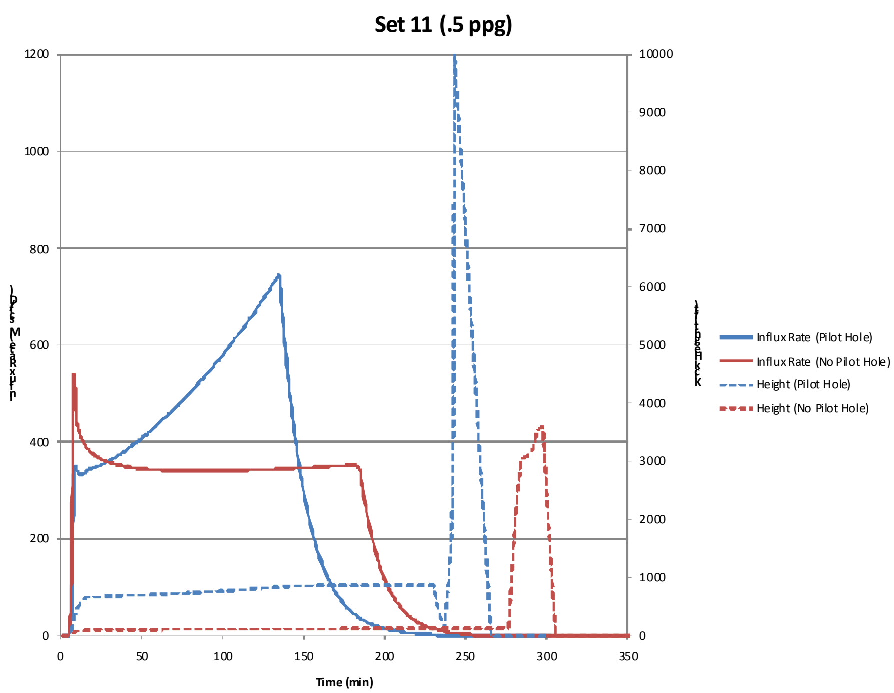


Fig. A-12—Set 11 (1 ppg) compared to Set 11 (.5 ppg)

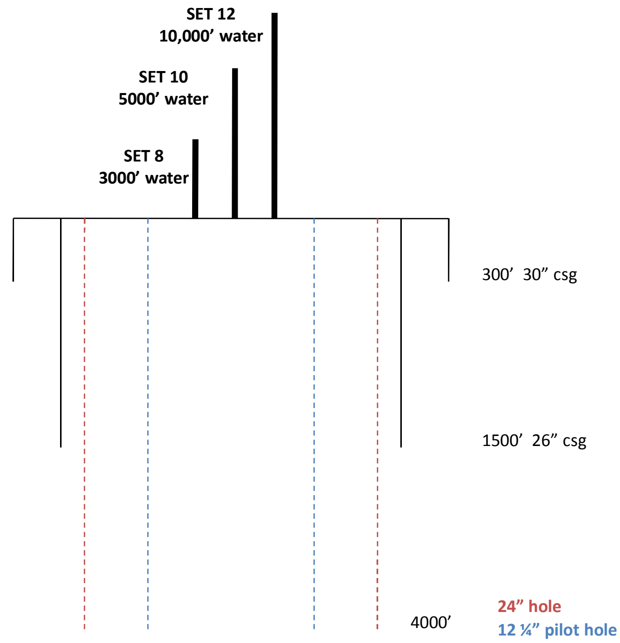


Fig. A-13—Diagram of Set 8, Set 10, and Set 12

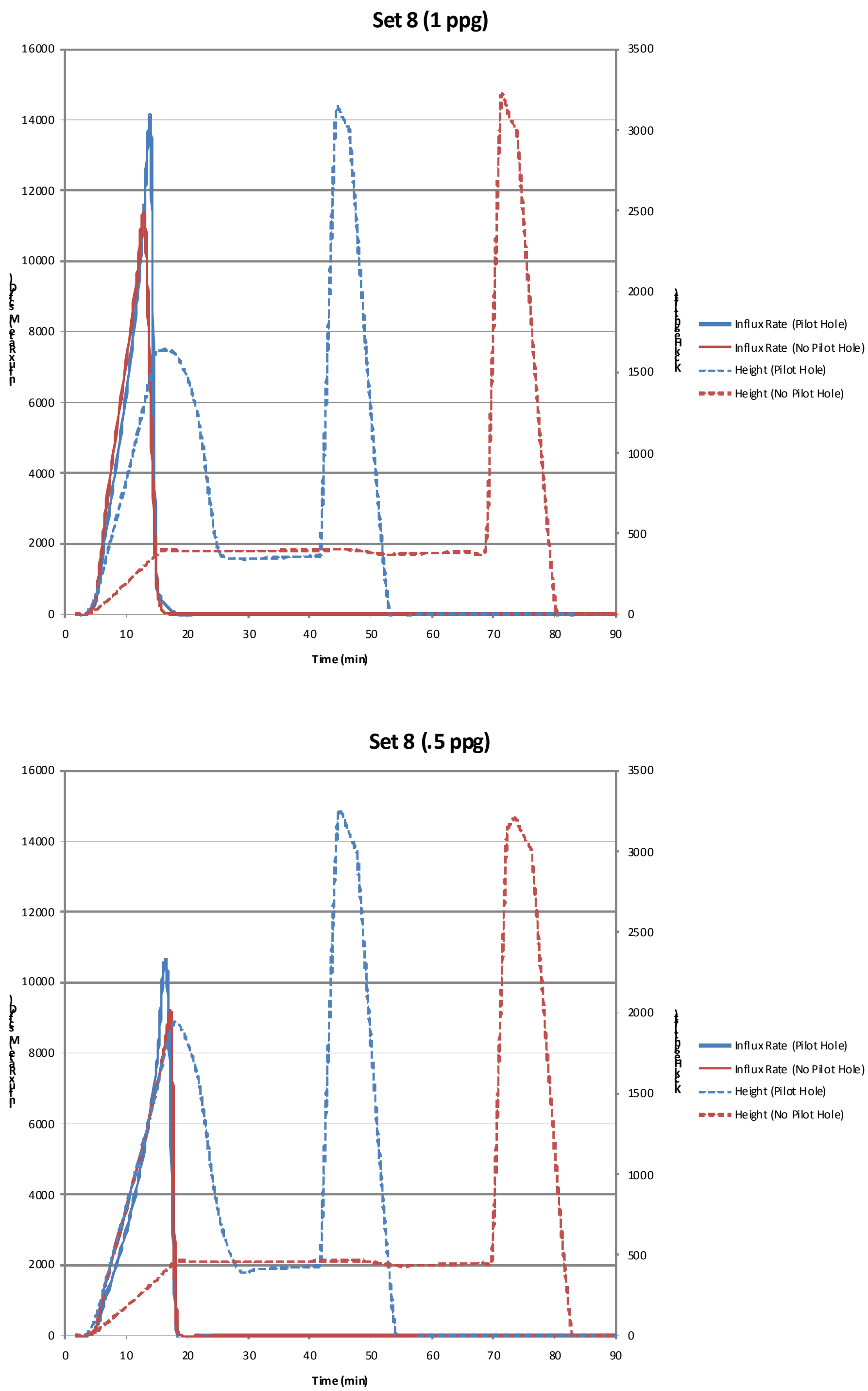
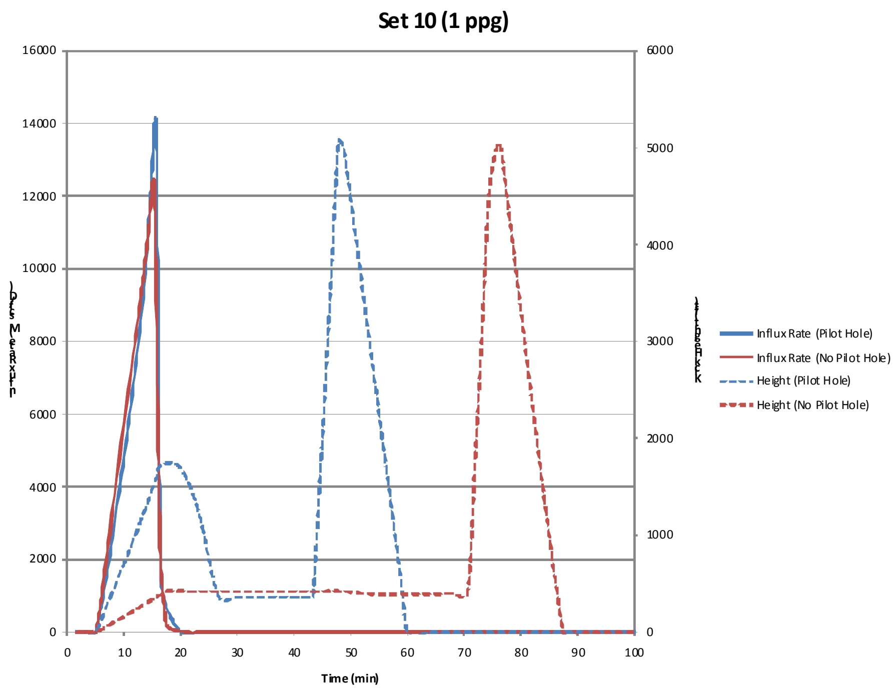


Fig. A-14—Set 8 (1 ppg) compared to Set 8 (.5 ppg)



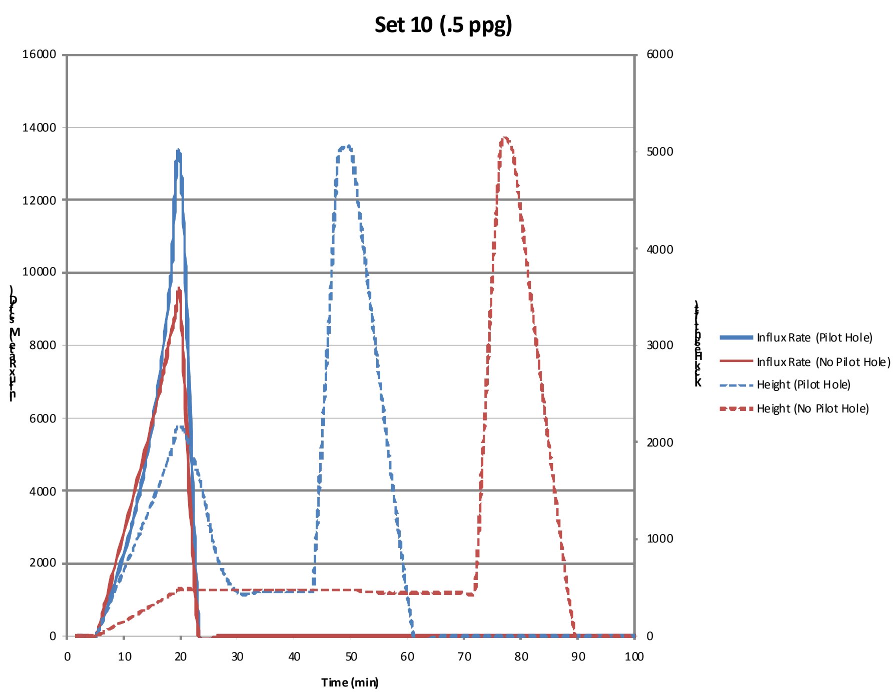


Fig. A-15—Set 10 (1 ppg) compared to Set 10 (.5 ppg)

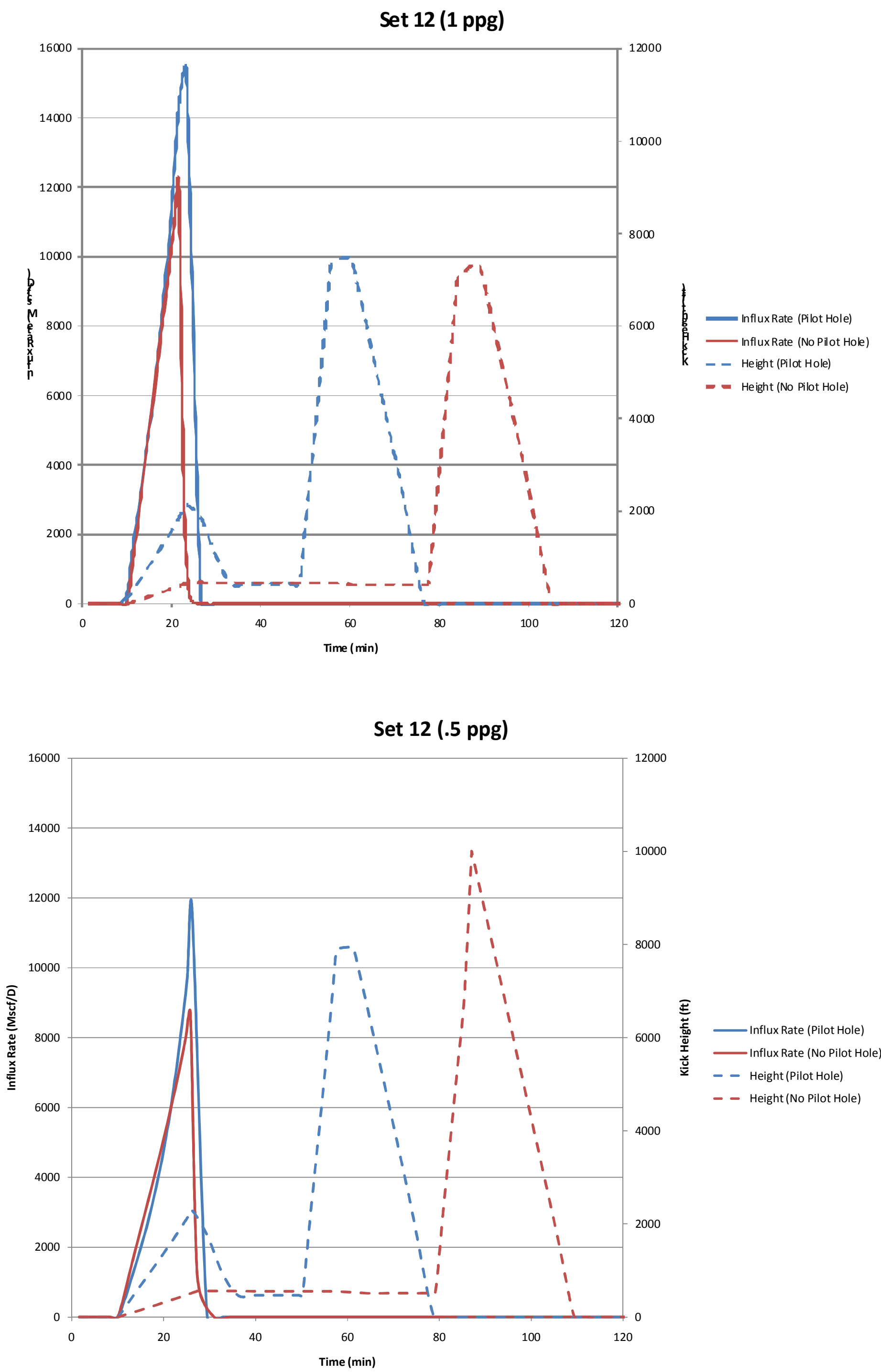


Fig. A-16—Set 12 (1 ppg) compared to Set 12 (.5 ppg)

Table A-1—Example of simulator output data

Time (mins)	Xtop (ft)	Xbotm (ft)	Height (ft)	Px@Top (psig)	Pit vol (bbls)	Mud Rate (gpm)	Gas Rate (Mscf/Day)	Pump P (psig)	Stand PP (psig)
1.67	1100	1100	0	0	0	650	0	1402	1402
3.33	988	1100	112	511	0.08	654	0	1401	1401
5	762	1100	338	392	0.98	678	0	1397	1397
6.67	753	1100	347	384	2.03	27	0	0	0
8.33	743	1100	357	379	3.11	27	0	0	0
10	733	1100	367	374	4.21	28	0	0	0
11.67	723	1100	377	369	5.34	29	0	0	0
13.33	712	1100	388	363	6.52	30	0	0	0
15	701	1100	399	357	7.74	31	0	0	0
16.67	689	1100	411	351	9.02	33	0	0	0
18.33	677	1100	423	345	10.36	34	0	0	0
20	666	1100	434	376	11.62	0	0	0	0
21.67	658	1100	442	397	12.47	0	0	0	0
23.33	653	1100	447	411	13.05	0	0	0	0
25	649	1100	451	421	13.44	0	0	0	0
26.67	647	1100	453	427	13.69	0	0	0	0
28.33	645	1100	455	431	13.86	0	0	0	0
30	644	1100	456	434	13.98	0	0	0	0

Table A-1 continued

Time (mins)	Choke P (psig)	Csg Seat P (psig)	BHP (psig)	Strokes (#)	Vol Circ (bbls)	ChK Open Dia Ratio (%)	InFlux (Mcf/D)	SS Inlet Pressure (psig)	SS Outlet Pressure (psig)
1.67	0	149	569	0	0	100	0	45	55
3.33	0	149	569	0	0	100	35	45	55
5	0	149	564	0	0	100	248	45	55
6.67	0	149	556	0	0	100	239	45	52
8.33	0	149	552	0	0	100	240	45	52
10	0	149	547	0	0	100	246	45	52
11.67	0	149	542	0	0	100	255	45	52
13.33	0	149	537	0	0	100	265	45	52
15	0	149	532	0	0	100	275	45	52
16.67	0	149	526	0	0	100	287	45	52
18.33	0	149	521	0	0	100	300	45	52
20	0	186	552	0	0	100	254	82	52
21.67	0	211	574	0	0	100	172	107	52
23.33	0	228	588	0	0	100	115	124	52
25	0	239	598	0	0	100	77	135	52
26.67	0	247	604	0	0	100	51	143	52
28.33	0	252	608	0	0	100	34	148	52
30	0	255	611	0	0	100	23	151	52

Table A-1 continued

Time (mins)	Xtop (ft)	Xbotm (ft)	Height (ft)	Px@Top (psig)	Pit vol (bbls)	Mud Rate (gpm)	Gas Rate (Mscf/Day)	Pump P (psig)	Stand PP (psig)
31.67	644	1100	456	436	14.05	0	0	0	0
33.33	644	1100	456	437	14.1	0	0	0	0
35	644	1100	456	438	14.13	0	0	0	0
36.67	644	1100	456	438	14.16	0	0	0	0
38.33	644	1100	456	439	14.17	0	0	0	0
40	644	1100	456	439	14.18	0	0	0	0
41.67	644	1100	456	439	14.19	0	0	0	0
43.33	644	1100	456	439	14.19	0	0	0	0
46.67	121	443	322	200	34.26	902	0	1449	1449
46.7	100	408	308	183	36.73	930	0	1449	1449
49.49	0	254	254	1000	46.51	853	267.4	1449	1449
50.56	0	201	201	1000	32.68	261	7861.7	1449	1449
51.77	0	126	126	1000	9.98	247	6380.5	1449	1449
52.08	0	100	100	1000	1.99	267	6066.4	1449	1449
52.25	0	15	15	1000	0.28	289	5716.2	1449	1449
52.28	0	0	0	0	0	650	0	1449	1449
55.09	0	0	0	0	0	650	0	1449	1449
55.21	0	0	0	0	0	650	0	1445	1445

Table A-1 continued

Time (mins)	Choke P (psig)	Csg Seat P (psig)	BHP (psig)	Strokes (#)	Vol Circ (bbls)	ChK Open Dia Ratio (%)	InFlux (Mcf/D)	SS Inlet Pressure (psig)	SS Outlet Pressure (psig)
31.67	0	257	613	0	0	100	15	153	52
33.33	0	259	614	0	0	100	10	155	52
35	0	260	615	0	0	100	7	156	52
36.67	0	260	616	0	0	100	5	156	52
38.33	0	261	616	0	0	100	3	157	52
40	0	261	616	0	0	100	2	157	52
41.67	0	261	617	0	0	100	1	157	52
43.33	0	261	617	0	0	100	1	157	52
46.67	0	264	617	257.9	51.59	100	0	189	59
46.7	0	248	617	260.4	52.08	100	0	183	57
49.49	1000	197	617	476.5	95.29	51.7	0	166	1058
50.56	1000	197	617	559.3	111.86	37.7	0	141	1022
51.77	1000	197	617	653.1	130.62	35.6	0	105	1024
52.08	1000	197	617	677	135.4	36.2	0	93	1025
52.25	1000	197	617	689.9	137.98	36.9	0	93	1051
52.28	0	197	617	692.2	138.43	100	0	93	55
55.09	0	197	617	909.9	181.98	100	0	93	55
55.21	0	197	617	918.8	183.75	100	0	93	55

VITA

Name: Lauren Kristen King

Address: Texas A&M University
3116 TAMU, RICH
College Station, TX 77843-3136

Email Address: lauren33king@hotmail.com

Education: B.S., Petroleum Engineering, The University of Oklahoma, 2007
M.S., Petroleum Engineering, Texas A&M University, 2009