TOP HOLE DRILLING WITH DUAL GRADIENT TECHNOLOGY

TO CONTROL SHALLOW HAZARDS

A Thesis

by

BRANDEE ANASTACIA MARIE ELIEFF

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

August 2006

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee, Jerome J. Schubert
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ABSTRACT

Top Hole Drilling with Dual Gradient Technology

to Control Shallow Hazards. (August 2006)

Brandee Anastacia Marie Elieff, B.S., Texas A&M University

Chair of Advisory Committee: Dr. Jerome J. Schubert

Currently the "Pump and Dump" method employed by Exploration and Production (E&P) companies in deepwater is simply not enough to control increasingly dangerous and unpredictable shallow hazards. "Pump and Dump" requires a heavy dependence on accurate seismic data to avoid shallow gas zones; the kick detection methods are slow and unreliable, which results in a need for visual kick detection; and it does not offer dynamic well control methods of managing shallow hazards such as methane hydrates, shallow gas and shallow water flows. These negative aspects of "Pump and Dump" are in addition to the environmental impact, high drilling fluid (mud) costs and limited mud options.

Dual gradient technology offers a closed system, which improves drilling simply because the mud within the system is recycled. The amount of required mud is reduced, the variety of acceptable mud types is increased and chemical additives to the mud become an option. This closed system also offers more accurate and faster kick detection methods in addition to those that are already used in the "Pump and Dump" method. This closed system has the potential to prevent the formation of hydrates by adding hydrate inhibitors to the drilling mud. And more significantly, this system

successfully controls dissociating methane hydrates, over pressured shallow gas zones and shallow water flows.

Dual gradient technology improves deepwater drilling operations by removing fluid constraints and offering proactive well control over dissociating hydrates, shallow water flows and over pressured shallow gas zones. There are several clear advantages for dual gradient technology: economic, technical and significantly improved safety, which is achieved through superior well control.

DEDICATION

This work is dedicated to my mother and father for always being my inspiration and support. They have always been there for me; sometimes with encouraging words, sometimes with advice, sometimes just to lend an ear, but always with love and understanding. I know, no matter what I do in life or where I go, they will always be there for me, and that means the entire world to me.

Thank you mom and dad, I couldn’t have done it without either of you.

ACKNOWLEDGEMENTS

Sincere thanks go to my advisor, Dr. Jerome J. Schubert, for his continuous support, advice and patience in answering all of my questions. Working under you has been an honor.

Dr. Hans C. Juvkam-Wold, thank you for always being patient and available to answer my questions and offer advice. I have benefited greatly from your knowledge and experiences.

Dr. Steve Suh, thanks for all your help, support and for agreeing to be part of my committee. It has been extremely valuable for me to learn from someone outside my department.

My gratitude goes to Rob Romas for being my computer expert. Also, thank you to the rest of my family; your support is greatly appreciated.

I also want to thank my office mates, Arash Haghshenas and Amir Paknejad, for taking the time to problem solve with me.

Dr. Jonggeun Choe, thank you for permitting me to use the Riserless Drilling Simulator you created.

Finally, I would like to thank Minerals Management Service and the Offshore Technology Research Center for making this research project possible.

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CHAPTER I

INTRODUCTION

In order to meet the world's increasing demand for energy, the search for oil and gas extends into increasingly hostile and challenging environments. Among these problematical environments are the deepwater regions of the world. As technology progresses the definition of deepwater becomes greater and greater every day, and as the water depth increases, the associated technical, economic and safety complexities increase proportionately. This has led to a high demand for new technologies throughout the oilfield, but with a specific focus on improving drilling technologies. The industry wide goals are to: increase accessibility to reserves, improve wellbore integrity, reduce overhead costs and, most importantly, provide a safe working environment. Applying a dual gradient technology to offshore drilling is not a new concept, but one that is being addressed with new fervor and can help meet all of these industry goals.

1.1 Dual Gradient Drilling Technology

One of the many challenges faced when drilling deepwater offshore wells is the decreasing window between formation pore pressures and formation fracture pressures. "In certain offshore areas with younger sedimentary deposits, the presence of a very narrow margin between formation pore pressure and fracture pressure creates

This thesis follows the style and format of *SPE Drilling and Completion.*

tremendous drilling challenges with increasing water depths."[1] This occurrence is explained as being the result of the lower overburden pressures, due to the lower pressure gradient of seawater, than that which is exerted by typical sand-shale formations. The resulting situation is that the overburden and fracture pressures in an offshore well are significantly lower, than those of an onshore well of a similar depth, and it is more difficult to maintain over pressure drilling techniques without fracturing the formations.[2] Typically, the method for combating this problem has been to fortify the wellbore casing, by increasing the number of casing strings set in the well during drilling and completions operations. However, this can be extremely costly, both from a materials cost perspective and a time cost perspective. It has been proven that the number of casing strings set in a well can be reduced if the difference between the pore pressure and fracture pressure can be managed better. This has resulted in the development of new Managed Pressure Drilling (MPD) techniques. The International Association of Drilling Contractors (IADC) Underbalanced Operations Committee defines MPD as: an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly.[3,4] One MPD technique that is being pursued for commercial use in deepwater environments is dual gradient drilling.

1.2 Dual Gradient Drilling Advantages

A dual gradient system removes the mud filled riser from the typical deepwater drilling system. In a conventional system the annulus section of the riser is filled with mud, and below the sea floor the pressure within the annulus is so high, that to avoid a pressure in the wellbore that exceeds the formation fracture pressure, it is necessary to set casing strings more frequently than is technically and economically desirable.

When using a dual gradient drilling system the riser is removed from the system (figuratively and/or literally depending upon the variation of the dual gradient system). This allows the pressure at the sea floor to be lower (salt water pressure gradient is lower than most drilling fluids' pressure gradient) than in a conventional system, and this allows the driller to more accurately navigate in the pressure window between formation fracture pressure and formation pore pressure. As long as there is a safe margin of approximately 0.5 ppg gradient between the wellbore annular pressure gradient and the fracture pressure gradient it is unnecessary to set casing strings as often as in the conventional system. An illustration of how the pressures are managed so that annular pressure remains above pore pressure at drilling depth but below fracture pressure at shallower depths in the well, can be seen in **Fig. 1**.

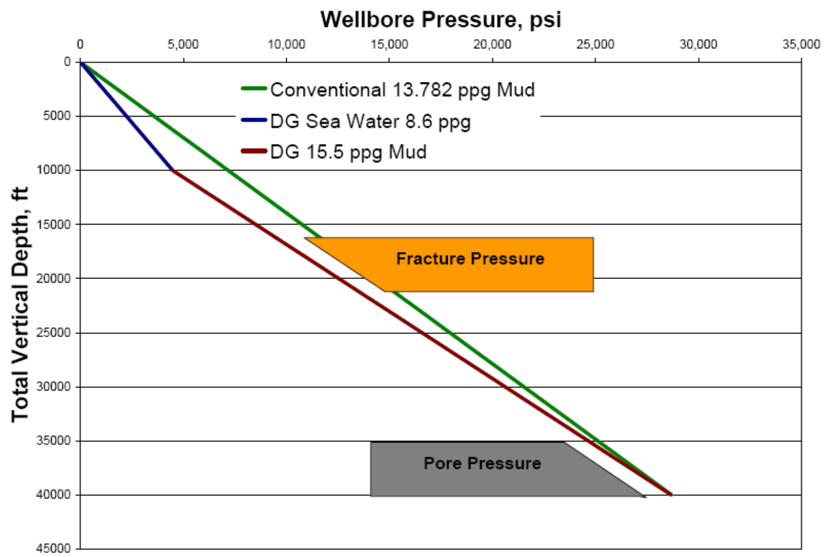

Fig. 1 - Illustration of Wellbore Pressures in a Dual Gradient System

Managing the pressure window between the formation fracture and pore pressures decreases the number of casing strings required to maintain wellbore integrity while drilling. A comparison between conventional deepwater drilling casing requirements and dual gradient deepwater drilling casing requirements can be seen in **Fig. 2** and **Fig. 3**.

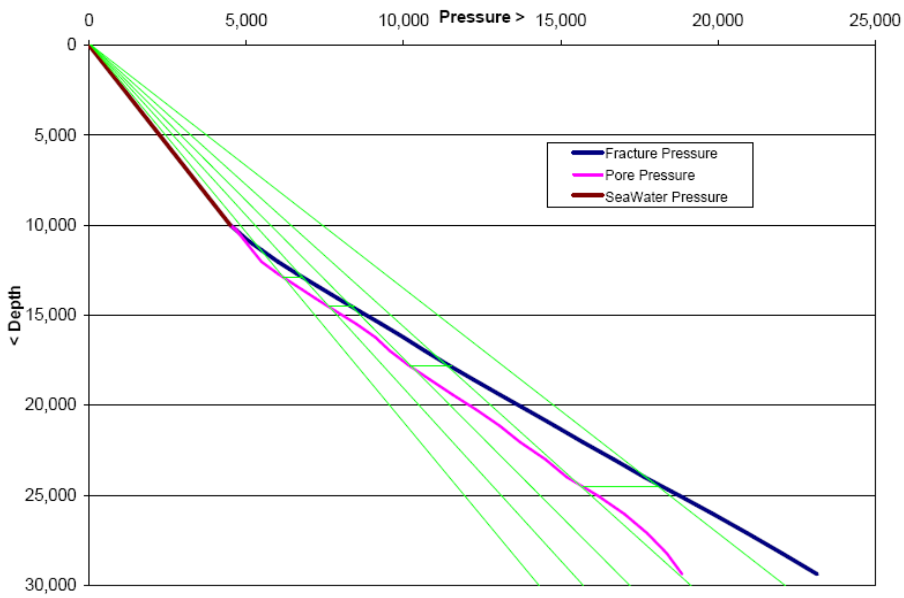

Fig. 2 - Graphical Casing Selection in a Conventional System

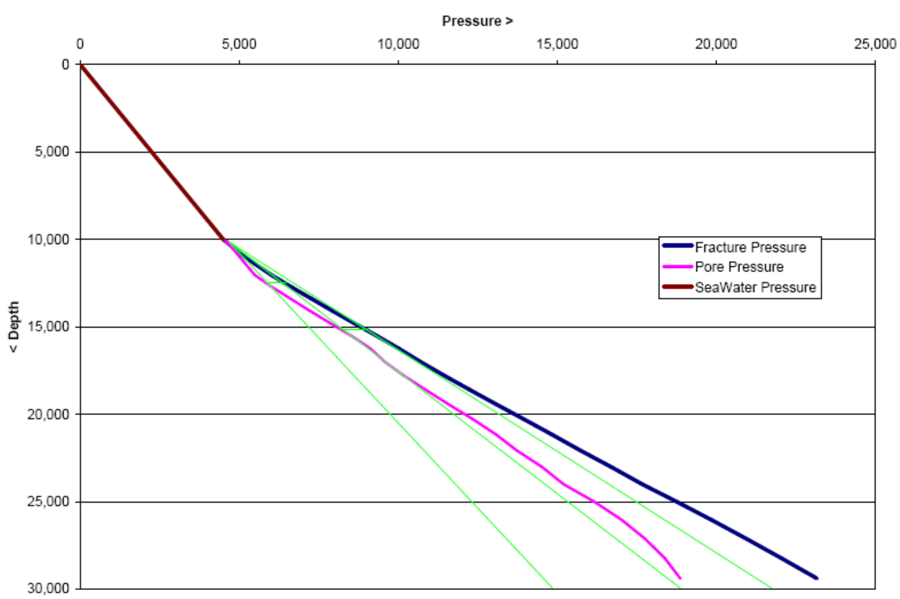

Fig. 3 - Graphical Casing Selection in a Dual Gradient System

When drilling conventionally in deepwater conditions the riser is treated as part of the wellbore and as the water depth increases the pressures within the wellbore change as though the depth of the well is increasing as well. However, when using the dual gradient drilling system procedures, the depth of the water is no longer a factor affecting wellbore pressure. It's like "taking water out of the way" (from the SubSea MudLift Drilling Joint Industry Project (SSMLDJIP) Phase III: Final Report through personal communication). Many benefits are realized by employing dual gradient drilling technology in a deepwater environment. A few of these benefits are:

- Fewer required casing strings
- Larger production tubing (accommodates higher production rates)
- Improved well control and reduction of lost circulation setbacks
- Lower costs, as the "water depth capabilities of smaller rigs may be extended".[5,6,7,8]

1.3 Dual Gradient Drilling History and Evolution

The concept of dual gradient drilling was first considered in the 1960s. At the time the idea was to simply remove the riser and therefore the technology was referred to as riserless drilling. The technology, however, was not pursued at the time, as there was no driving economic or technical need for improving offshore drilling. As offshore drilling progressed into deeper water the desire to improve project development economics and technical characteristics resurrected the technology in the 1990s.

Beginning in 1996, four main projects began in an effort to improve deepwater drilling technology by implementing dual gradient systems. The four projects were: Shell Oil Company's project, the Deep Vision project, Maurer Technology's Hollow Glass Spheres project and the SubSea MudLift Joint Industry Project.[9]

The most extensive study was the SubSea MudLift Joint Industry Project (JIP) that began in 1996 when a group of deepwater drilling contractors, operators, service companies and a manufacturer gathered to discuss the merits of riserless or dual gradient drilling. The result was an extensive system design, construction and field test that would span five years. The main reason the group was interested in developing this technology was the promise it held to potentially reduce the necessary number of casing strings, specifically in the Gulf of Mexico, where high pore pressures and low formation strengths require operators to set casing strings often during drilling and completion operations.[5,6,7]

The SubSea MudLift JIP was charged with the tasks of designing the hardware and the necessary procedures to effectively and safely operate the dual gradient drilling system. Phase I of the project took place from September, 1996 to April 1998 and cost approximately $1.05 million. Phase I was the Conceptual Engineering Phase and the participants were to create a dual gradient drilling design that: was feasible, considered well control requirements, and was adaptable to a large rig fleet (not just a few specialized rigs).[5,6,7] Phase I is considered to have been very successful and resulted in a design for drilling extended reach, 12¼” holes at TD, in 10,000 ft of water. One of the most challenging design issues was how to lift the mud after it had been circulated through the wellbore.

Once circulated, through the wellbore, the mud or drilling fluid, is loaded with free gases, metal shavings, rock chips and other drilling debris. What kind of pump is capable of pumping the mud from the sea floor back to the rig floor? The JIP answered this question in Phase I with the response of a positive displacement diaphragm pump. However, no such pump existed that met the JIP’s needs, so it was concluded that the JIP would have to design and build one. Other conclusions of Phase I were: this technology is more than feasible, however, well control procedures would need to be modified, and a field test is necessary, specifically in the Gulf of Mexico where the driving need for this technology is based.

Phase II, or Component Design, Testing, Procedure and Development, began in January of 1998 and continued until April of 2000 and cost approximately $12.65 million. The purpose of Phase II was to actually design, build and test the subsea pumping system, create all the drilling operations and well control procedures and to determine the best methods for incorporating the dual gradient drilling technology onto existing drilling rigs. Phase II resulted in: a proven reliable seawater-driven diaphragm pumping system, drilling and well control procedures capable of withstanding potential equipment failure cases, and an understanding that system training program was necessary.

Phase III, or System Design, Fabrication and Testing, began in January of 2000 and was completed in November of 2001 with a budget of $31.2 million. The purpose of Phase III was to validate the design of the technology through an actual field application. This goal was accomplished and the first dual gradient test well was spudded on August 24th, 2001 and by August 27th, 2001 the 20" casing had been run and cemented. On August 29th, the JIP SubSea MudLift Drilling system was finally put to test in the field. Although there were many problems initially (especially with the electrical system), "Once a problem was identified and repaired, it stayed repaired." (From the SSMLDJIP Phase III: Final Report through personal communication). Ultimately ninety percent of the field test objectives were met and considered successful. Although still requiring industry support, dual gradient drilling was proven a viable and useful technology.

Another JIP project began in 2000 and culminated with a successful test application in 2004. This was the development of AGR Ability Group's (AGR) Riserless Mud Recovery System (RMR). The system was designed and tested specifically for the application of drilling the top hole portion of a wellbore. The desired results were to increase control over shallow water and gas flows, and to increase the depth of the surface casing strings by reducing the number of dynamically selected seats. The RMR system was rated to a depth of 450 meters of seawater, but was tested in only 330 meters of seawater. The successful field test took place in December of 2004 in the North Sea.[10] The conclusions of this JIP were that using dual gradient technology for top hole drilling results in:

- Improved hole stability and reduced washouts

- Improved control over shallow gas and water flows
- Improved gas detection (due to accurate flow checks and improved mud volume control)
- Prevention of the accumulation of mud and cuttings on subsea templates and preventing the dispersion of drilling fluids into environmentally sensitive areas
- Reduced number of necessary surface casing strings.

The most current research being done in the dual gradient drilling area is a project through the Offshore Technology Research Center (OTRC), a division of the National Science Foundation (NSF) that is a joint partnership between Texas A&M University and the University of Texas. The project the OTRC is pursuing, which is initially funded by the Minerals Management Service (MMS), is called the “Application of Dual Gradient Technology to Top Hole Drilling”. The purpose of the project is to begin a JIP that results in the design and test of a dual gradient drilling system geared specifically to drilling the top hole portion of the wellbore in a deepwater environment. Although this has already been done in shallow water, this OTRC project is to focus on the application of a Dual Gradient Top Hole Drilling System (DGTHDS) in deepwater. The driving factors for this project are the increasingly hazardous shallow hazards commonly found in deepwater environments, especially in the Gulf of Mexico. These shallow hazards: over pressured shallow gas zones, shallow water flows and methane hydrates are jeopardizing drilling activities in deepwater. It is hypothesized that a DGTHDS can control these shallow hazards while drilling in deepwater. The project will explore increasing control over these hazards in two ways: one is in the increased well control available from a DGTHDS and the second is to improve the wellbore integrity by setting surface casing deeper than in conventional drilling applications. Once the shallow hazards are controlled and the conductor and surface casing are set deeper this will also allow for safer drilling of the intermediate depth portions of the well and ultimately reduce the number of casing strings used throughout the well.

1.4 Achieving the Dual Gradient Condition

There are different methods used to achieve the dual gradient condition when drilling offshore. Basically, a dual gradient is achieved when there are two different pressure gradients in the annulus, the volume between the wellbore inner diameter (ID) and the drill string (DS) outer diameter (OD). The condition can be achieved by: reducing the density of the drilling fluid in a portion of the wellbore or riser, removing the riser completely and allowing sea water to be the second gradient, or managing the level of the mud within the riser and allowing the second gradient within the riser to be that of another fluid.[11]

One method, nitrogen injection, is based on air drilling procedures and underbalanced drilling techniques. This technique uses nitrogen to reduce the weight of the mud in the riser.[6] In an effort to reduce the amount of nitrogen required to lower the mud pressure gradient in the riser, a concentric riser system is considered the most economical. In this system a casing string is placed inside the riser with a rotating BOP at the top of the riser (in the moonpool) to control the returning flow. The mud is held in the annulus between the casing string and the riser, and nitrogen is injected at the bottom of the riser into the annulus. Buoyancy causes the nitrogen to flow up the annulus which reduces the density and pressure gradient of the drilling fluid as a result of nitrogen's liquid holdup properties. The injection of nitrogen can reduce the weight of a 16.2 ppg mud to 6.9 ppg. This is can be applied when the second gradient is desired to be even lower than that of seawater, which has a typical pressure gradient of 8.55 ppg. The most noteworthy characteristic about this method of using nitrogen injection to create two gradients is that the formation is not underbalanced, as one might initially conclude. The cased hole is underbalanced to a depth, but below the casing, in the open hole, the wellbore is actually overbalanced, which prevent an influx of fluids from the formation into the wellbore. One serious concern with this method of creating a dual density system is the uncertainty as to whether or not well control and kick recognition will be more difficult. In this case, the system is very dynamic and well control and kick detection are definitely more complex, however, not necessarily unsafe.[12]

Another method of creating a dual gradient system is to begin by drilling the upper portions of the well without a riser and by simply returning the drilling mud to the sea floor. In this setup the pressure inside the wellbore at the seafloor is the same as the pressure at the sea floor. In other words the pressure gradient from the ocean surface to the sea floor is that of the seawater pressure gradient. Then, inside the wellbore a heavier than typical mud is used to maintain proper pressures while drilling. Once the initial spudding has taken place and the structural pipe has been set, the subsea BOP stack is installed with some variation on a typical system. The mud returns are moved, from the wellhead by a rotating diverter, to a subsea pump which returns the mud to the rig floor through a 6” ID return line. Drilling continues with this setup and the remaining casing strings are set using this dual gradient system where mud returns, to the rig, through a separate line.[6] An illustration of this system can be seen in **Fig. 4**.

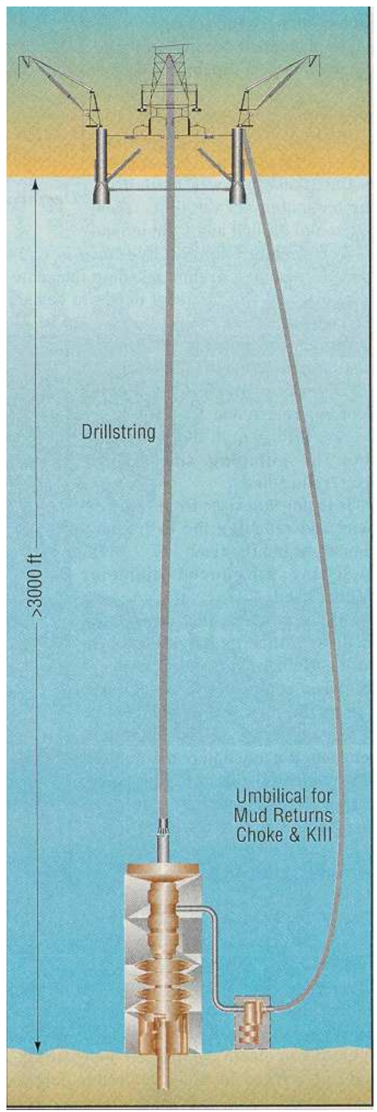

Fig. 4 - Illustration of a Riserless Dual Gradient System[12]

Initially, this method was regarded with skepticism because of the perceived difficulty of kick detection. However, with more advanced technology, and the ability to monitor pressure in the subsea BOP accurately, kick detection and the detection of circulation loss is reliable and safe. In fact, it is possible for the riser to act as a trip tank in this system.[12]

Another method of creating a dual gradient system is similar to that of the nitrogen injection. A Department of Energy (DOE) project was done to test how the injection of hollow spheres into the mud returning through the riser can create a dual gradient system. This system is similar to the nitrogen injection method, but separating the gas from the mud at the rig floor is simplified because dissolved gas in the drilling fluid is not a concern. The glass spheres are separated from the mud and re-injected at the base of the riser. **Fig. 5** illustrates a typical Hollow Glass Sphere Injection system.

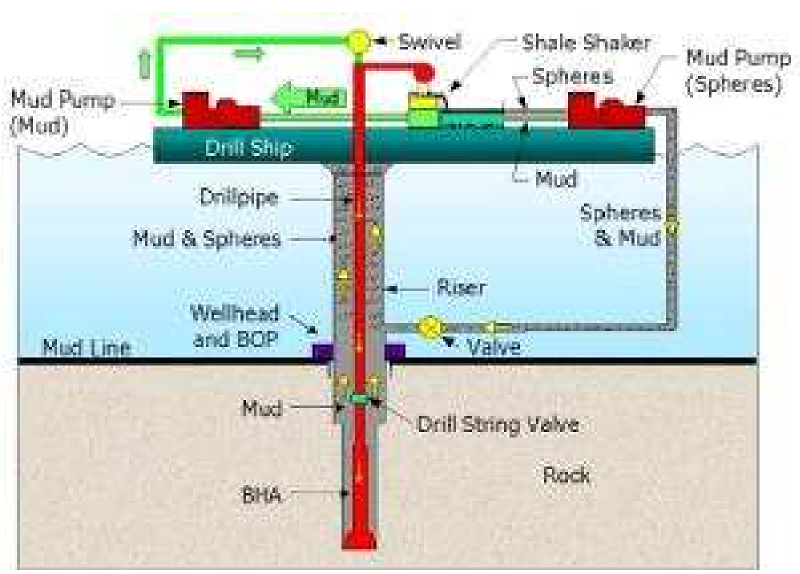

Fig. 5 - Illustration of a Hollow Sphere Injection Dual Gradient System[13]

1.5 A Typical Dual Gradient System and Components

The most commonly researched and pursued method of achieving a dual gradient system is the riserless system, described in Chapter I (1.4) and shown in Fig. 4. This system pumps the drilling mud through the drill string, out the drill bit nozzles, into the open hole, up the annulus, into the BOP stack, through the rotating head, into the subsea mud pump, and up the 6” return line to the rig floor. The mud is then cleaned at the rig floor and recycled back to the drill string to be circulated again.

The main components in this system that are unique to the dual gradient system are: the drill string valve, the rotating head, the subsea mud pump, and the mud return line.

Once the drilling mud flows up the annulus to the BOP it must be diverted so that it can be pumped up the return line. In the SubSea MudLift Drilling JIP this was accomplished through a rotating head referred to as the SubSea Rotating Diverter (SRD). This SRD is capable of handling $6^5/_8$” 5½” and 5” drill pipe and has a retrievable rotating seal rated to 500 psi. Although, typically, the pressure difference across this seal is less that 50 psi. Once the mud is diverted to the SubSea Mud Pump the main concern is handling of solids. This was addressed through the addition of a SubSea Rock Crusher Assembly. Basically, as the returning mud passes through this assembly any rock chips are crushed between two rotating spheres with teeth. A photo of this rock crusher assembly can be seen in **Fig. 6**.

Fig. 6 - SubSea Rock Crushing Assembly Used in SubSea MudLift JIP[I]

Once the cuttings are crushed and processed through the unit they have been reduced to small pieces. The crushed cuttings and mud are then passed through into the SubSea MudLift Pump. The requirements that the pump is subject to are very demanding. The pump must be able to pump up to 5% volume of mud cuttings, produce a flow rate between 10 and 1,800 gallons per minute, operate to a maximum pressure of 6,600 psi, within a temperature range between 28 ºF and 180 ºF, and finally be able to pump 100% gas when the need arises to circulate a gas kick out of the well. As mentioned earlier in Chapter I (1.3) the necessary result is a positive displacement diaphragm pump that is hydraulically powered by seawater. The seawater providing hydraulic power is pumped from the rig floor using conventional surface mud pumps down an auxiliary line to the mud pump. In **Fig. 7** you can see a cross section illustration of the mechanisms at work within this diaphragm pump.

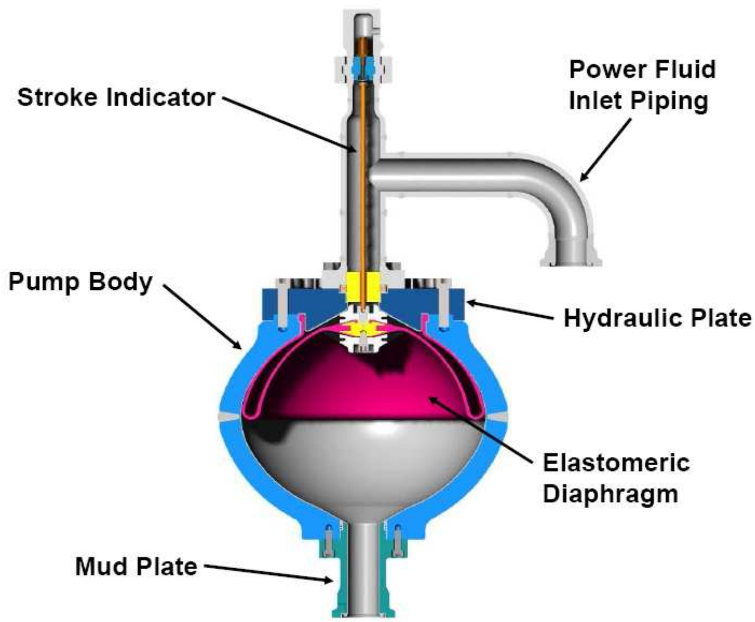

Fig. 7 - Illustration of a Cross Section of a Diaphragm Positive Displacement Pump[I]

This pump also acts as a check valve by preventing the hydrostatic pressure of the drilling fluid within the return line from impacting on the pressure within the wellbore. This pump is normally run in an automatic mode, which means it is set to run at a constant inlet pressure, and the pump rate is automatically altered to maintain a constant inlet pump pressure. This allows the driller to change the surface mud pumping rates as if the system were conventional.[14] During well control procedures the pump can be switched from a constant inlet pressure mode to a constant pump rate mode in the advent that a kick enters the well and annulus pressure needs to be increased to maintain a desirable annulus/pore pressure balance.

The last main component of the riserless dual gradient drilling system is the Drill String Valve (DSV). The DSV was developed to control the U-tube effect, which is often encountered in drilling and completion operations. The U-tube effect is cause when the total hydrostatic pressure (HSP) of the fluid in the DS is different than the total HSP of the fluid in the annulus. In response the fluid will flow through the drill bit nozzles from the region (DS/annulus) with the higher HSP to the region with the lower HSP. In conventional operations the U-tube effect only occurs occasionally and most commonly during cementing. However, in riserless dual gradient drilling, the U-tube effect is always a factor, as the HSP of the fluid in the DS is often more than the HSP of the fluid in the wellbore annulus plus the HSP at the seafloor. The concern is, when mud circulation is stopped to make or break a drill pipe connection, the mud within the drill string will drain into the wellbore and up the annulus. The DSV assembly is placed inline with the drill string, and when mud circulation is stopped the DSV is closed to prevent the free fall of drilling fluid within the drill string (from the SSMLDJIP Phase III: Final Report through personal communication). An illustration of the system with the DSV assembly in place can be seen in **Fig. 8**.

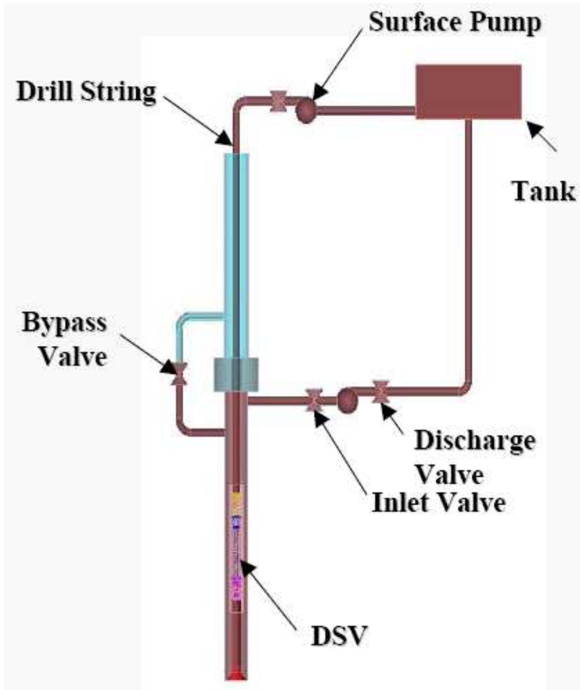

Fig. 8 - Illustration of Dual Gradient System w/ Drill String Valve[I]

1.6 Dual Gradient Operations versus Conventional Operations

There are several aspects of dual gradient drilling that are different from that of conventional drilling operations. Regarding general drilling operations a smaller rig may be used for applying dual gradient technology than what would be conventionally used. There are a couple of reasons for this: one is in order to support a 21” riser (common size used in conventional drilling) the rig must be large enough to support the weight of the riser. In a riserless dual gradient drilling system the weight hanging from the rig is reduced to that of the drill string, the mud return line and the umbilical control lines. Also contributing to the large rig size, necessary for conventional drilling, are the deck space limitations that are caused by the necessity of having large drilling fluid volumes on hand. In a conventional drilling system a large volume of mud is necessary in order to fill the riser. Also a problem, is that a high volume of mud is lost during the "Pump and Dump" method for drilling the tophole portion of the wellbore. In a DGTHDS only the drill string must be filled with mud and the mud is returned to the rig floor where it is cleaned and recycled. This reduces the necessary deck space and the costs associated with supplying the necessary mud. Reducing the weight rating of the rig and the necessary deck space allows for the use of a smaller rig.

Another difference between a conventional drilling system and a dual gradient drilling system is that removing the riser leaves only the drill string to be affected by the forces exerted by the ocean currents. Since the diameter of the drill string is considerably smaller than that of a 21" riser, the impact these forces have on drilling operations is reduced.

Perhaps the most time and cost saving benefit that results from the application of dual gradient drilling, over conventional drilling is how the necessary number of casing strings is reduced. This does two things, first this allows for the final tubing size to be larger, which increases production flow rates, and second the amount of time necessary to drill a deepwater well is reduced, because less time is spent on completions.

From a safety perspective the main differences between dual gradient drilling and a conventional drilling system are the well control procedures. Basically, a dual gradient system, as a managed pressure drilling technique, improves well control. A Modified

Driller's Method employed by riserless dual gradient drilling is described in Chapter I, Section 1.7.

The similarity between the two systems is that the drilling program is not significantly altered. Trips and connections are handled in the same manner and the basic acts of drilling, such as bit selection and general rig procedures, are not altered.[9]

1.7 Dual Gradient Systems' Well Control Procedures

Well control is not simply something that must be implemented in the eventuality of a kick. Proper well control must be considered throughout all phases of drilling operations. This means from the initial planning, through the well completion and into the abandonment stages. The basic purpose of proper well control is to prevent blowouts, and create a quality wellbore. This is best accomplished through proper prediction of formation pore and fracture pressures, the design and use of the proper equipment (BOP, kick detection devices and casing) and proper kick detection and kill procedures.[9,15]

Taking a kick while drilling is common and must be prepared for. Quick kick detection and proper well control response is imperative. Kicks may be detected through several different observations and the driller must be aware of all inconsistencies experienced while drilling. The most common methods of kick detections are: a drilling break, a flow increase, a mud pit gain, a decrease in circulating pressure that is accompanied by an increase in pump speed within the surface pumps, well flows when the surface pumps are off, an increase in rotary torque, drag and fill and an increase in drill string weight.

These kick detection techniques are just as applicable, if not more so, in dual gradient drilling as in conventional drilling. The major difference between dual gradient drilling and conventional drilling is the U-tube effect. The U-tube effect occurs when drilling mud circulation through the drill string, up the annulus and through the subsea mud pump is stopped. The U-tube effect causes the system to try and equalize the pressure difference between the hydrostatic pressure within the drill string and the hydrostatic pressure in the annulus by draining the drilling fluid contained within the drill string, through the drill bit nozzles, into the annulus. Again, this occurs any time the HSP of the fluid in the DS is different than the HSP of the fluid in the annulus. The solution to the U-tube effect is simply a drill string valve (DSV), which is described in Chapter I, Section 1.5. There is however, a benefit to the U-tube effect that occurs in dual gradient drilling. This effect allows for lower circulating pressures by the rig pumps and makes small changes in pressures easier to detect. These pressure changes often serve as excellent kick detectors.

Another method of kick detection involves the inlet and outlet pressure of the subsea mud pump. When a kick enters the wellbore the annular flow rate of the drilling fluid increases by an amount that is equal to that of the kick influx rate. Generally, while drilling, the subsea mud pumps are set to operate in a constant inlet pressure mode. This means, if the rate of flow increases due to a kick influx the pumping rate of the subsea mud pumps will automatically increase as well, to maintain a constant subsea pump inlet pressure. This is an excellent indicator to the driller that a kick is occurring and the driller can then take the measures necessary to stop the kick influx into the annulus.

Approximately half of all kicks occur while tripping the drill pipe into or out of the hole. The best method, which is also the earliest, of determining a kick has taken place is to measure the volume of mud required to fill the hole after removing some of the pipe. This is usually done every five stands of drill pipe. If the mud required to fill the hole is less than the volume of the drill pipe removed, a kick has entered the wellbore. This is a kick detection employed by conventional drilling practices. In dual gradient drilling this kick detection procedure must be considered for use both with a DSV and without a DSV. When operating without a DSV an accurate determination of the amount of mud necessary to fill the wellbore is not possible until after the U-tube effect has ceased. When operating with a DSV, the volume of mud to fill the hole is equal to the volume of a cylinder with a diameter equal to the OD of the pipe removed. The only major change from conventional operations is that more frequent hole fill intervals are necessary and if possible continuous fill of the hole is even more desirable.

As soon as a kick is detected it is necessary to take the necessary actions to stop the influx, so that excessive casing pressures can be avoided. Excessive casing pressures can result in lost circulation, formation fracturing and the worst case scenario of a surface blowout. When a kick is initially detected usually the response is to shut-in the well by closing the BOP stack. When shutting in a dual gradient drilling system immediate shut-in should not be performed unless a DSV is in place. The DSV must be closed before shut-in to ensure that the hydrostatic pressure of the mud within the drill string does not cause formation fracturing. If there is no DSV in place it is necessary to allow the U-tube effect to take place and then to shut-in the well by closing the BOP. When the U-tube effect is taking place it is difficult to prevent any additional influx from entering the wellbore. This is why it is recommended to employ the use of a DSV in all dual gradient drilling operations. A DSV allows immediate shut-in of the well and killing procedures can then commence in a manner more similar to that of conventional drilling. However, the following procedures should be adhered to when the driller is not employing a complete shut-in scenario, i.e. no DSV.[9,16,17,18] This is known as a modified Driller's Method, and is considered the most effective and common in a dual gradient system.

1 Slow the subsea pumps to the pre-kick rate (maintain the rig pumps at constant drilling rate).

2 Allow the drillpipe pressure to stabilize, and record this pressure and the circulating rate.

3 Continue circulating at the drillpipe pressure and rate recorded in step 2 until kick fluids are circulated from the wellbore.

4 The constant drillpipe pressure is maintained by adjusting the subsea pump inlet pressure in a manner similar to adjusting the casing pressure with the adjustable choke on a conventional kill procedure.

5 After the kick fluids are circulated from the wellbore, a kill fluid of higher density is circulated around to increase the hydrostatic pressure imposed on the bottom hole.

Other methods such as the Wait and Weight Method and the Volumetric Method are applicable to a riserless dual gradient system. However, these methods both require the use of a DSV. Although the DSV is applicable with the Driller's method it is unnecessary and it is always good to ensure that proper well control relys on as few of pieces of equipment as possible.

1.8 Dual Gradient Drilling Challenges

The main challenges that are associated with dual gradient drilling are basically those that are associated with all new technologies. The technology has been designed, developed and successfully field tested. The key now is to streamline the equipment and procedures to ensure that dual gradient technology is seamlessly the next step forward in deepwater drilling.

In the field test of the SubSea MudLift Drilling JIP the main delay while drilling the test hole was equipment commissioning problems. The technology successfully functioned the way it was designed but had electrical and commissioning delays. Once these "kinks" were worked out of the system the test hole was drilled with minimal delays (from the SSMLDJIP Phase III: Final Report through personal communication).

In order for the industry to embrace a new technology such as dual gradient drilling, the “kinks” must be all worked out and the new technology must offer substantial benefits over conventional technologies.

An interesting point is that a dual gradient system will need to be somewhat customized depending on: water depth, temperatures above and below the mud line, formation pressures, ocean conditions and a number of other conditions. However, even in conventional technology, no two wells are ever drilled with the exact same equipment or procedures. The difference is that personnel are familiar with how to alter conventional technology to fit with the current drilling environment. In order for personnel to become as familiar with dual gradient technology as conventional technology, training is a necessity (from the SSMLDJIP Phase III: Final Report through personal communication).

Eventually, dual gradient technology will become a conventional technology and be one of the many tools in a driller’s toolbox. The remaining obstacles are equipment commissioning, personnel training and overcoming initial industry resistance.

CHAPTER II

SHALLOW HAZARDS

The category of shallow hazards includes three main subcategories: methane hydrates, shallow gas zones and shallow water flows. These hazards can be found in deepwater environments and generally between the mudline and approximately 5,000 ft below the mudline. Each of these hazards create a different problem for exploration and production (E&P) companies, which are pursuing oil and gas fields in deepwater. Shallow hazards may appear to cause problems only during drilling and completion operations, but in reality can have long term ramifications that affect production long into the life of the field. Shallow hazards compromise: the safety of operations, well control, wellbore integrity and reservoir accessibility.

2.1 Methane Hydrates

Hydrates are natural gases, typically methane, that are trapped within ice crystals. Since most of the hydrates that are found are methane gas, this shallow hazard is commonly referred to as methane hydrates. Methane hydrates form in low temperature, high pressure zones where water and methane are present together. Above 68 ºF methane hydrates cannot exist, however below 68 ºF methane hydrates can exist depending on the pressure within the zone. Typically methane hydrates are found along the sea floor and in isolated pockets below the mud line until the geothermal gradient causes the formation temperature to increase above 68 ºF. Methane hydrates can cause problems in two ways: by forming within equipment or by dissociating during drilling operations.

2.1.1 Formation of Hydrates Within Drilling Equipment

The most common way methane hydrates impact on drilling operations is when hydrates form within the drilling system. Particularly critical is if they form in the Blowout Preventer (BOP) stack or in the choke and kill lines. These hydrates can block the lines and BOP and prevent the BOP from functioning properly (closing in the case of an emergency). It is necessary, for the safety of the drilling and completions crew, that a system be in place that can prevent the formation of hydrates within equipment. Chemicals known as hydrate inhibitors can be added to the drilling fluid to prevent the formation of hydrates within the equipment, but in a conventional top hole drilling system, these chemicals are not an option, because of environmental restrictions. However, if a closed system is used and the drilling fluid is returned to the rig floor, hydrate inhibitors can be added to the drilling fluid.

2.1.2 Dissociation of Hydrates into the Wellbore During Drilling Operations

The second way hydrates can compromise the safety of operations is less common, but equally dangerous. When hydrates are lying on the sea floor or within the formation, the gas is trapped within the ice. Drilling through these hydrates breaks the ice crystals imprisoning the gas and allows the gas to dissociate from the ice and into the wellbore. This dissociating gas acts like a shallow gas kick and the driller is immediately faced with the complication of handling gas within the annulus. If the gas is not controlled and the pressures within the wellbore annulus are not stabilized more reservoir fluid (gas/oil/water) may enter the wellbore and further complicate well control procedures.

2.2 Shallow Gas Flows

Shallow gas flows are another common shallow hazard. It is even hypothesized that shallow gas flows are a result of methane hydrates that have been buried within the formation, and as the formation temperature increases the gas is released from the ice crystals and trapped within the formation. Shallow gas zones are often over pressured and pose a serious well control risk. Once a gas kick enters the wellbore the annulus pressure begins to decrease, which allows more gas to enter the wellbore. If the driller does not apply a well control method to increase annular pressure, prevent further influx and circulate the gas kick safely out of hole, disastrous events such as surface and underground blowouts can be the result. Not only can blowouts destroy the rig, but they can also result in the loss of life. One particularly catastrophic event was the explosion of the Piper Alpha rig in the North Sea in 1988.[19] The remnants of this disaster can be seen in **Fig. 9**. Events such as this are completely unacceptable and any method of preventing such an event needs to be designed, tested and implemented as a high priority.

Fig. 9 - The Piper Alpha Platform: North Sea – 167 Died in Explosion and Fire[20]

2.3 Shallow Water Flows

The third main shallow hazard is shallow water flows. Shallow water flows do not generally pose a safety threat to the rig and personnel, but the conventional method of dealing with shallow water flows is not conducive to high quality casing seats, and this can threaten the well's safety. In conventional top hole drilling, these water zones are often allowed to produce, and can cause erosion in the formation and ultimately compromise the integrity of the surface casing. Eventually the casing can collapse and the entire wellbore may be destroyed. This is a very time consuming and expensive problem that has been experienced by operators in the past. A particularly expensive and complicated example of this situation was experienced by the Shell Deepwater Development, Inc. Company in the Ursa field, located in the Mississippi Canyon Block 854 in the Gulf of Mexico. The field was discovered in 1990, and the first well, MC 854 #1 was plugged and abandoned after setting 20" surface casing as a result of buckling casing. Well MC 854 #2 was successfully drilled to TD, but was also plugged and abandoned due to severe shallow casing wear that resulted from the buckling of casing across shallow sands.[21] An illustration of how the production of these shallow water zones can cause erosion behind casing seats can be seen in **Fig. 10**.

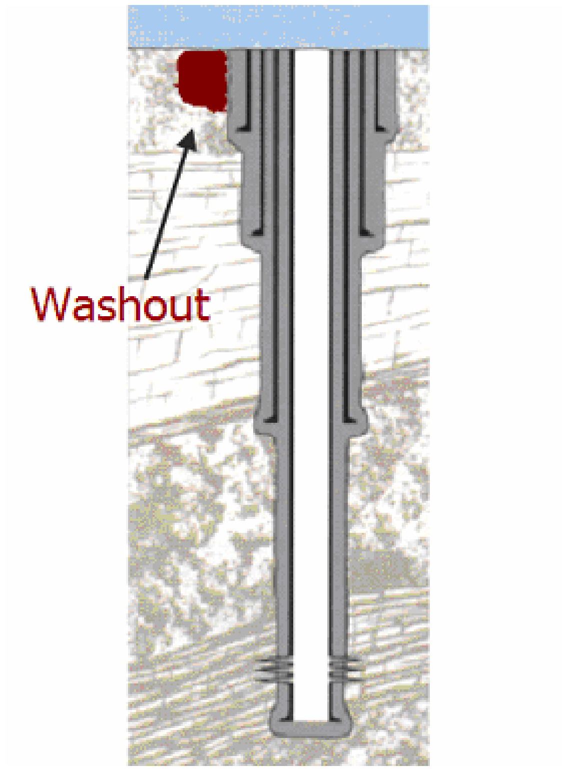

Fig. 10 - Formation Erosion Behind Casing Resulting from Shallow Water Flows

CHAPTER III

CONTROLLING SHALLOW HAZARDS WITH DUAL GRADIENT TECHNOLOGY

Shallow hazards are a problem and controlling these shallow hazards has become a priority for E&P companies operating in deepwater environments. That is why it is surprising to find the conventional method of drilling the top hole portion of the wellbore, "Pump and Dump", is still used as the industry standard. "Pump and Dump" is lacking in many ways and dual gradient technology can easily control shallow hazards with acceptable modifications to current drilling and completions equipment, drilling procedures and well control procedures.

3.1 Conventional Technology: "Pump and Dump" Method Description

The current "Pump and Dump" method used to drill the top hole portion of the wellbore in deepwater, is fairly basic. The mud is pumped down the drill string, into the wellbore up the annulus and onto the seafloor. There is no BOP stack in place and there is no drilling fluid return to the rig floor. The "Pump and Dump" method can cause several problems. These problems include, but are not limited to: limited well control, increased number of shallow casing strings, poor wellbore integrity, increased initial hole size (requiring larger rigs), loss of mud and finally a negative environmental impact, which limits acceptable types of drilling fluids that meet regulations.

The “Pump and Dump” method offers few methods of kick detection and limited well control methods when a kick does occur. Because the mud is not returned to the rig floor there is limited down hole pressure information available to the driller and often the driller relies on visual kick detection methods to determine when an influx has entered the wellbore. In an effort to avoid shallow hazards like hydrates and shallow gas zones, seismic data is carefully analyzed and the surface location of the rig ma be moved to avoid these zones. This can result in longer measured depth (MD) direction wells. In the eventuality that these zones can not be avoided the driller has no proactive well control methods in their “tool box”. In the case of shallow water flows, these zones are generally allowed to produce until the formation pressure is reduced. Unfortunately, by the time this happens erosion of the formation has often already occurred.

Dealing with these shallow hazards can increase the number of shallow casing strings, when compared to drilling in normally pressured zones. To ensure that the drilling fluid can be heavy enough to maintain over balanced drilling, even when drilling through over pressured shallow gas zones, casing must be set often to prevent shallower parts of the wellbore from fracturing and causing lost circulation. Lost circulation can result is stuck pipe or worse, an underground blowout.

Poor wellbore quality is also often the result of “Pump and Dump”. The “Pump and Dump” method limits the use of specialty drilling fluids that lift cutting out of the hole at lower circulation rates. This means, in order to lift the cutting with a less specialized mud, the circulation rate is increased. This increased drilling fluid circulation rate can cause wellbore erosion, and the wellbore often becomes jaggedly shaped, which makes a high quality cement job become difficult to implement.

Aside from the technical, safety and economical disadvantages to “Pump and Dump” method, there is the obvious environmental impact, not to mention how the continuous loss of drilling fluid can become a high cost constraint to the development of a field. The environmental restrictions placed on the types of acceptable drilling fluids can prevent the driller from using the optimal fluid for the formation type and also prevents the addition of chemicals that prevent problems such as the formation of hydrates within equipment. The “Pump and Dump” method is not really a method at all. It is simply the standard rut that the industry has fallen into. It is obvious, upon reviewing the disadvantages and lack of advantages, that a new method of top hole drilling is imperative.

Applying dual gradient drilling technology to drilling the top hole portion of the wellbore is likely to eliminate the majority, if not all, of these associated problems.[22] Possibly the most important reason that dual gradient technology would be beneficial in top hole drilling is the control over shallow hazards, the improved well control and the improved safety.

3.2 Riserless Dual Gradient Drilling Technology Description

Understanding the DGTHDS does not require a significant stretch of the imagination. The flow of the drilling fluid does not vary greatly from conventional riser drilling. It is, however, different than the "Pump and Dump" method. The drilling fluid is pumped down the drill string, where it enters the wellbore and flows back through the wellbore annulus to the rotating diverter. The rotating diverter transfers the returning mud to the subsea mud pump. This subsea mud pump, when in typical drilling mode operations, is set to operate at a constant subsea inlet pressure. This means the pumping rate is automatically altered to maintain constant pump inlet pressure. This changes during well control procedures, which is discussed in Chapter III (3.2.2). The mud is then pumped up a 6" return line to the rig floor, where it is recycled and pumped back down the drill string. The other main line from the rig to subsea pump is the seawater supply line that supplies hydraulic power to the diaphragm subsea pump. There are inherent benefits to this system over "Pump and Dump", simply because the DGTHDS is a closed system. The amount of required mud is reduced because the drilling fluid is recycled and reused. Seafloor pollution is reduced and because there is no environmental impact, the number of drilling fluid type meeting regulation increase. It has been proven that selecting the proper drilling fluid can significantly improve drilling operations. Also important is, how the closed system allows for the admission of backpressure to increase the wellbore annulus pressure. This allows the driller to maintain the proper wellbore annulus pressure with heavier mud at lower circulation rates. This prevents the wellbore erosion that is commonly associated with the "Pump and Dump" method. This additional pressure control also improves kick detection, offers proactive well control methods and ultimately reduces the number of required shallow casing strings.

3.2.1 Kick Detection

The DGTHDS offers more accurate and faster kick detection methods in addition to those that are already utilized during the "Pump and Dump" method. As, discussed earlier, in standard drilling mode the subsea pump is operated at a constant inlet pressure. When a kick enters the wellbore the pump inlet pressure increases. In order to maintain a constant inlet pressure, the subsea pump responds by increasing its pumping rate to compensate for the additional inlet pressure created by the influx. This increase in pump rate is the first kick indicator. As the subsea pump increases its pumping rate, the subsea pump's outlet pressure increases and the levels in the mud pit increase. These are the second and third kick indicators. Finally, in response to the pressure changes within the wellbore the surface pump pressure decreases, the fourth kick indicator. When a kick is detected the system uses a modified driller's method to prevent further influx and circulate the kick safely out of hole.

3.2.2 Well Control "Modified Driller's Method"

As soon as the system detects a kick, the subsea pump is returned to the pre-kick rate and a constant pumping rate mode is maintained, which is equal to the surface pumping rate. This creates back pressure on the fluids within the wellbore annulus and increases bottomhole pressure until it is balanced with formation pore pressure, and further influx is prevented. It is important to record the stabilized drillpipe pressure and the pumping rate. Circulation of the fluids is then continued and the recorded drillpipe pressure is maintained at balance by changing the subsea pump rate. (This is similar to an adjustable choke in a conventional kill procedure.) Circulation is continued until kick fluids are removed from the wellbore. Once the kick fluids have been removed from the wellbore a kill weight mud is circulated to increase the hydrostatic pressure imposed on the bottomhole and drilling can resume. A graphical representation of this method can be seen in **Fig. 11**.

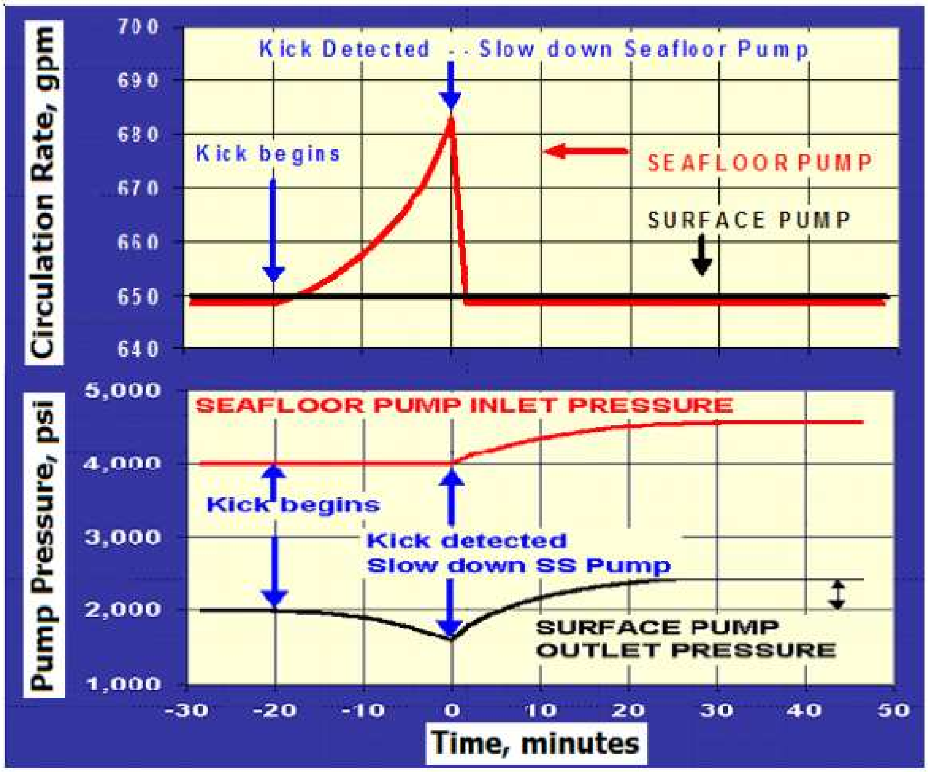

Fig. 11 - Graphical Depiction of Modified Driller's Method[12]

It is visible in Fig. 11, that the subsea pump rate increases, to maintain a constant inlet pressure, as the influx enters the wellbore. At the same time the surface pump outlet pressure decreases. Once the kick is detected and well control procedures commence you can see the rate of the subsea pump return to the pre-kick rate which is equal to that of the surface pump. It can also be seen how this causes the subsea pump inlet pressure and surface pump outlet pressures to increase.

3.3 Dual Gradient Controlling Methane Hydrates

As described earlier, methane hydrates impact on drilling operations by forming within the equipment and by dissociating within the wellbore annulus. Dual gradient technology applied to top hole drilling controls both of these problems caused by methane hydrates.

3.3.1 Preventing Hydrate Formation

The introduction of a closed system allows for chemicals, such as hydrate inhibitors to be added to the drilling fluid. These hydrate inhibitors have been proven very successful at preventing the formation of hydrates in drilling and production equipment.

3.3.2 Controlling Dissociating Hydrates

In the case of drilling through dissociating hydrates, a significant well control problem, dual gradient technology offers the advantage of fast kick detection. When methane hydrates dissociate into the wellbore, the dual gradient drilling systems reacts the same was as if a gas influx has entered the wellbore. The subsea pump inlet pressure will increase and the subsea pump rate will automatically increase to compensate. Then the pit gain warning and increased subsea pump outlet and decreased surface pump outlet pressures will alert the driller to employ well control methods. The subsea mud return system supplies the driller with back pressure control over the formation that prevents the dissociating methane hydrates from causing other influxes. The dissociating methane hydrates can be proactively and safely circulated from the wellbore and drilling can resume quickly.

3.4 Dual Gradient Controlling Shallow Gas Flows

A DGTHDS controls shallow gas flows the same way it controls dissociating methane hydrates: through effective kick detection and proactive well control methods. Again the gas influx into the wellbore is quickly detected and the modified driller's method quickly circulates the kick from the wellbore and prevents further influx. The drilling fluid weight is adjusted for the new formation pore pressure and drilling continues without the need to set, dynamically selected, casing seats.

3.5 Dual Gradient Controlling Shallow Water Flows

Shallow water flows are easier to control that methane hydrate dissolution or gas kicks. Controlling these shallow water flows will allow the driller to prevent the erosion of the formation and ultimately ensure that the operator will have a wellbore of high quality, because the casing seats are securely cemented to the formation.[23]

3.6 Dual Gradient Drilling Controlling Shallow Hazards Summary

This is a new technology that is still in the research and development stage, but it has all the signs of significantly benefiting the offshore drilling industry and to be adopted as a conventional technology. The technical and safety benefits associated with this new technology far outweigh the inherent industry resistance to the implementation of a new technology. The benefits that the industry stands to gain from the implementation of a DGTHDS vary from financial to safety to environmental.[10]

CHAPTER IV

TOP HOLE DUAL GRADIENT DRILLING SIMULATION

4.1 Riserless Drilling Simulator

The Riserless Drilling Simulator used, was originally created, as part of Dr. Jonggeun Choe's Ph.D. dissertation at Texas A&M University. The simulator was later adapted for use in the SSMLDJIP. A screen shot of the opening page to the simulator can be seen in **Fig. 12**.

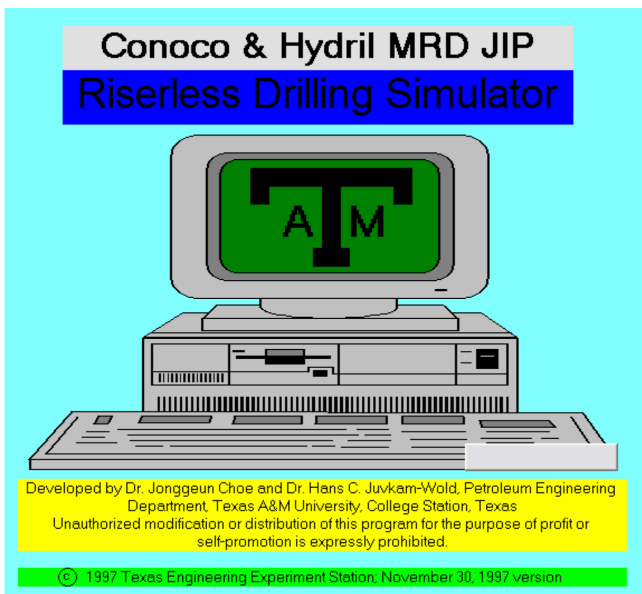

Fig. 12 - Riserless Drilling Simulator Introduction Page

This simulator was used, with the express permission of Dr. Jonggeun Choe and Dr. Hans C. Juvkam-Wold, exclusively for the purpose of researching the application of dual gradient technology to top hole drilling.

4.2 Simulation Parameters

After opening the simulator, the main menu is presented and several options are available. The first step is to change the input data from the default options, or open previously saved input data if re-running a previous simulation. The main menu can be seen below in **Fig. 13**.

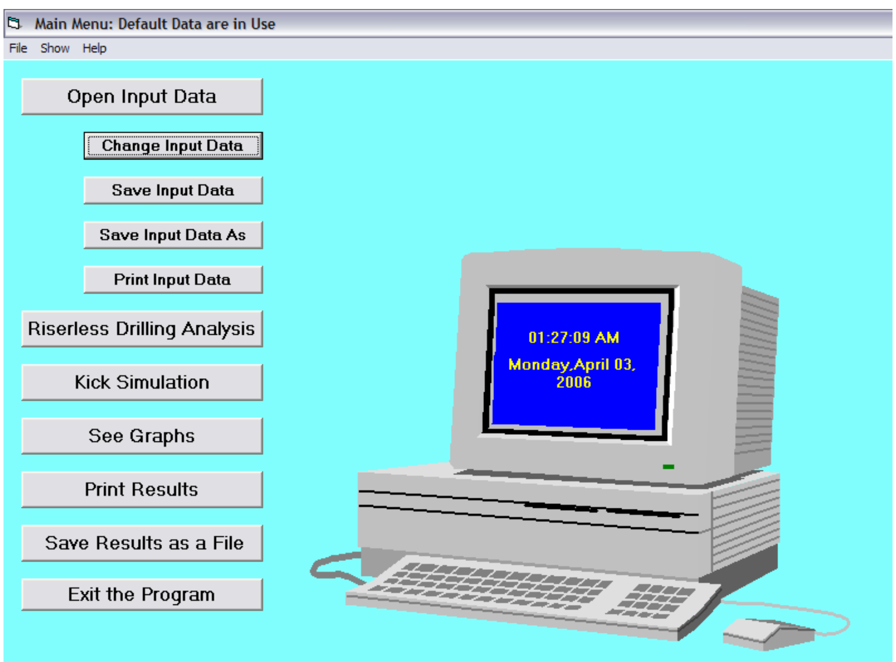

Fig. 13 - Main Menu of Riserless Drilling Simulator

Once the user has entered the necessary input data the gas kick simulation can be run by clicking the "Kick Simulation" button on the Main Menu screen. **Fig. 14, 15, 16, 17, 18** and **19** show the input data screens and the information required to properly run a kick simulation. The input data types are discussed below with each figure.

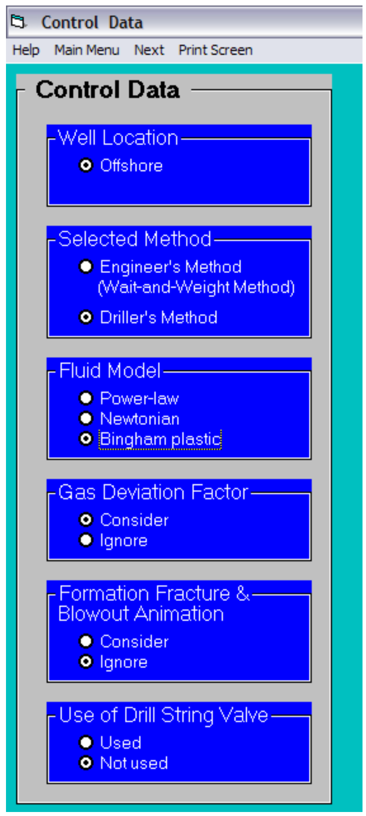

Fig. 14 - Simulator Control Data Input Screen

Fig. 14 shows the basic control data that needs to be entered for each simulation. The well control method used in all simulation runs is the "Modified Driller's Method" described previously in Chapter III. In the case of this simulation, the use of a Drill

String Valve (DSV) is not necessary when the "Modified Driller's Method" is the choice of well control methods. During the "Modified Driller's Method" the well is never shut-in, so the U-tube effect does not impact on operations. Since the U-tube effect is not applicable, the use of DSV is unnecessary. The rest of the data options selected in Fig. 14 remained constant throughout all simulation runs.

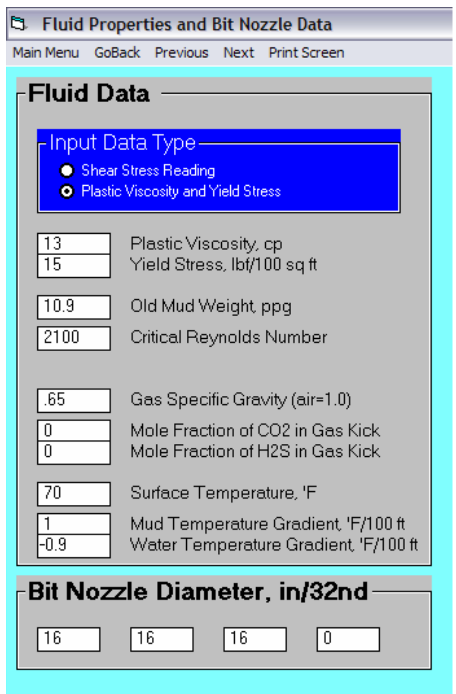

Fig. 15 - Simulator Fluid Data Input Screen

Fig. 15 shows the fluid data input screen. The only data, in this input screen, that was not held constant through all simulation runs were the Old Mud Weight, the Plastic Viscosity and the Yield Stress of the Mud. These parameters varied based on the pore pressures encountered at drilling depth. The different mud properties will be discussed in Chapter IV. The gas specific gravity, surface temperature, temperature gradients and bit nozzle sizes remained constant through all simulation runs.

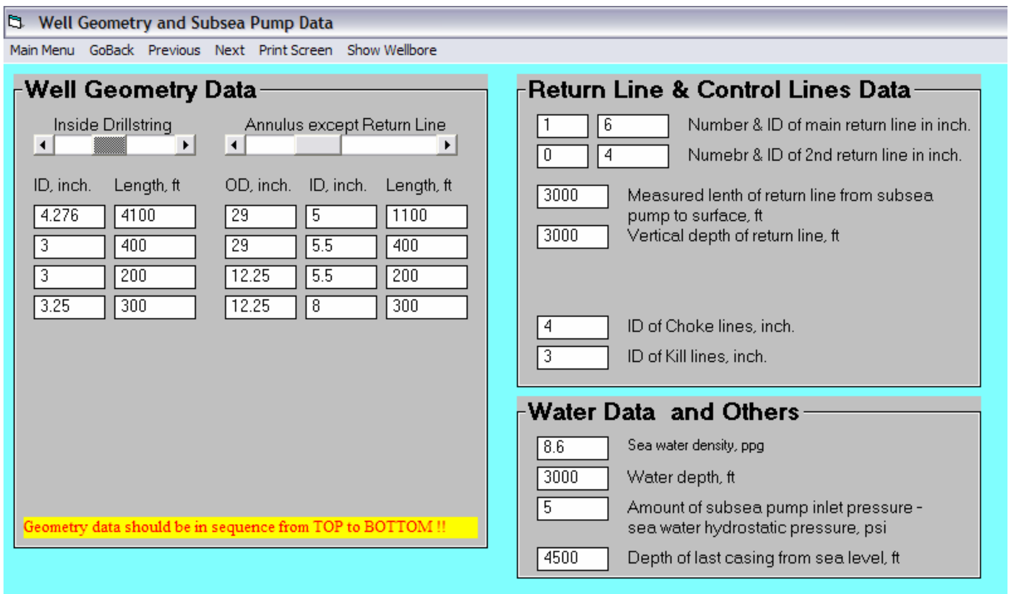

Fig. 16 - Simulator Well Geometry Data, Return Line and Control Lines Data and Water Data and Other Input Screen

Fig. 16 shows the well geometry data as well as the return line and water data. The use of one 6" main return line remained constant. Also remaining constant was the sea water density of 8.6 ppg and the 5 psi amount of subsea pump inlet pressure – sea water hydrostatic pressure. In each simulation run the well geometry was modified, as well as the length of the return line, the depth of the last casing point and the depth from the rig to the seafloor. After entering the well geometry data, the simulator produces a visual representation of the wellbore so the user may double check for any possible mistakes. An example of this visual representation of the wellbore can be seen in Fig. 17.

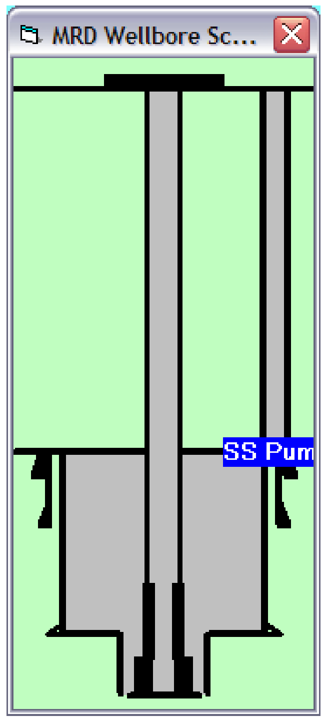

Fig. 17 - Illustration of Entered Wellbore Geometry Data

Other data that is modified, for each simulation run, is the kick data and the pore and fracture pressures, shown in Fig. 18. The kick data is manipulated by changing the amount of formation over pressure, which results in a kick intensity that is calculated in ppg. The pit gain warning level can be changed, so the pit gain kick indicator is more or less sensitive. Last on this input screen, the pore and fracture pressures are entered manually based on sea water depth. The pressures used varied based on water depth, but are analogous to a field found in the deepwater region of the Gulf of Mexico. This field actually possesses a pore/fracture pressure window that is abnormally small. The reason for using this window was to determine if this system (dual gradient top hole drilling) is capable of handling an extreme field environment. The Pore and Fracture Pressure Regimes (P&F PR) can be seen in Appendix B.

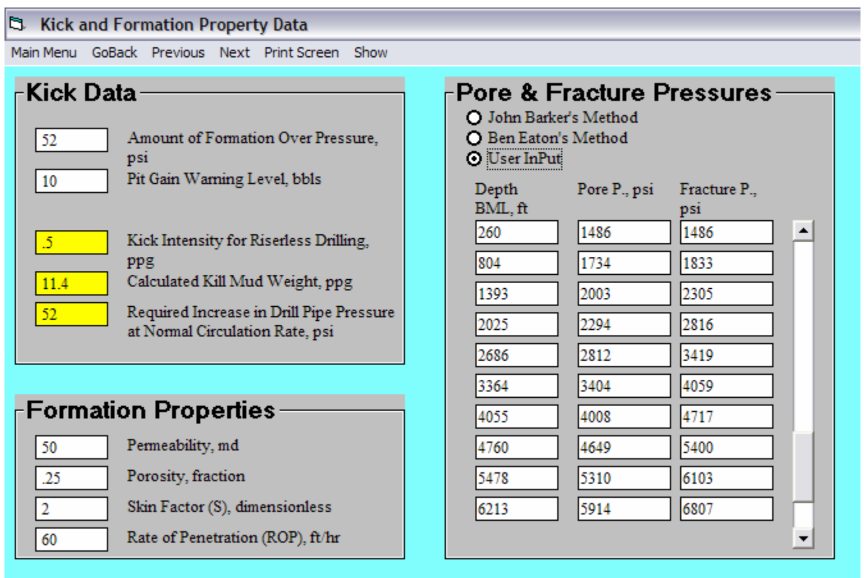

Fig. 18 - Simulator Kick Data, Formation Properties and Pore and Fracture Pressures Input Screen

The final input screen that must be entered is the pump data, surface choke valve data and the types of surface conditions. This screen can be seen in Fig. 19 and the data shown in this figure remained constant throughout all simulation runs.

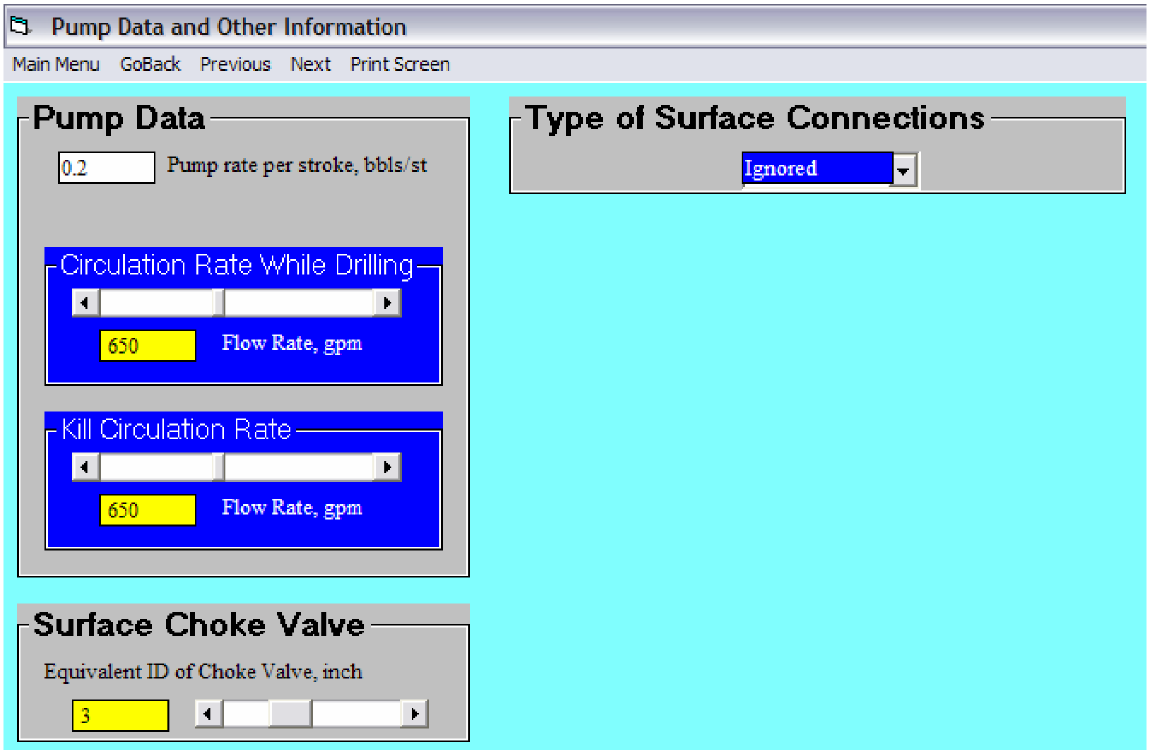

Fig. 19 - Simulator Pump Data, Surface Choke Valve and Type of Surface Connections Input Screen

Two sets of simulation runs were performed in order to determine the well control limits of this Dual Gradient Top Hole Drilling System (DGTHDS). The first set was designed simply to understand the limits of this system. The second was designed to test the limits of this system specifically in a field with a similar pore/fracture pressure window to the field that was already encountered in the Gulf of Mexico. The parameters of each simulation set are described in Chapter IV.

4.2.1 Simulation Run Set #1

In this simulation set the system was tested in three different water depths, resulting in different pore and fracture pressure regimes (P&F PR) and, therefore, different required mud properties, three different drilling depths below mud line (BML), two formation overpressures and finally two different kick sizes. One parameter that was chosen to remain constant based on typical wellbore schematics was the 30" conductor pipe set to a depth of 1,500 ft BML. Below the conductor pipe a pilot hole size of 12 ¼" was drilled. The variable parameters for each simulation are shown below in Table 1. The flowchart that describes the determination of run order can be seen in Appendix A, and the spreadsheets showing all of the input data for each run can be seen in Appendix C.

Table 1 - Variable Parameters of Simulation Set #1

Run #	Water Depth	P&F PR #	Mud Weight	Mud Plastic Viscosity	Mud Yield Point Stress	Depth of 12 ¼" Pilot Hole BML	Formation Over Pressure	Pit Gain Warning Level
	ft		ppg	cp	lbf/ 100 sq. ft	ft	ppg	bbl
1	3,000	#1	8.8	5	17	500	0.5	10
2	3,000	#1	8.8	5	17	500	0.5	50
3	3,000	#1	8.8	5	17	500	1	10
4	3,000	#1	8.8	5	17	500	1	50
5	3,000	#1	12.5	16.5	9	2,500	0.5	10
6	3,000	#1	12.5	16.5	9	2,500	0.5	50
7	3,000	#1	12.5	16.5	9	2,500	1	10
8	3,000	#1	12.5	16.5	9	2,500	1	50
9	3,000	#1	14	21	9	4,500	0.5	10
10	3,000	#1	14	21	9	4,500	0.5	50
11	3,000	#1	14	21	9	4,500	1	10
12	3,000	#1	14	21	9	4,500	1	50
13	5,000	#2	8.8	5	17	500	0.5	10

Table 1 Continued

Run #	Water Depth	P&F PR #	Mud Weight	Mud Plastic Viscosity	Mud Yield Point Stress	Depth of 12 ¼" Pilot Hole BML	Formation Over Pressure	Pit Gain Warning Level
	ft		ppg	cp	lbf/ 100 sq. ft	ft	ppg	bbl
14	5,000	#2	8.8	5	17	500	0.5	50
15	5,000	#2	8.8	5	17	500	1	10
16	5,000	#2	8.8	5	17	500	1	50
17	5,000	#2	12.5	16.5	9	2,500	0.5	10
18	5,000	#2	12.5	16.5	9	2,500	0.5	50
19	5,000	#2	12.5	16.5	9	2,500	1	10
20	5,000	#2	12.5	16.5	9	2,500	1	50
21	5,000	#2	14	21	9	4,500	0.5	10
22	5,000	#2	14	21	9	4,500	0.5	50
23	5,000	#2	14	21	9	4,500	1	10
24	5,000	#2	14	21	9	4,500	1	50
25	10,000	#3	8.8	5	17	500	0.5	10
26	10,000	#3	8.8	5	17	500	0.5	50
27	10,000	#3	8.8	5	17	500	1	10
28	10,000	#3	8.8	5	17	500	1	50
29	10,000	#3	12.5	16.5	9	2,500	0.5	10
30	10,000	#3	12.5	16.5	9	2,500	0.5	50
31	10,000	#3	12.5	16.5	9	2,500	1	10
32	10,000	#3	12.5	16.5	9	2,500	1	50
33	10,000	#3	14	21	9	4,500	0.5	10
34	10,000	#3	14	21	9	4,500	0.5	50
35	10,000	#3	14	21	9	4,500	1	10
36	10,000	#3	14	21	9	4,500	1	50

4.2.2 Simulation Run Set #2

Simulation Set #2 was run specifically to test the DGTHDS in a field when proper casing selections have been made. This means that the casing selections should be determined graphically based on the pore/fracture pressure window in the top hole portion of the wellbore. The graphical selection of surface casing seats for 3,000 ft of water depth can be seen in **Fig. 20**.

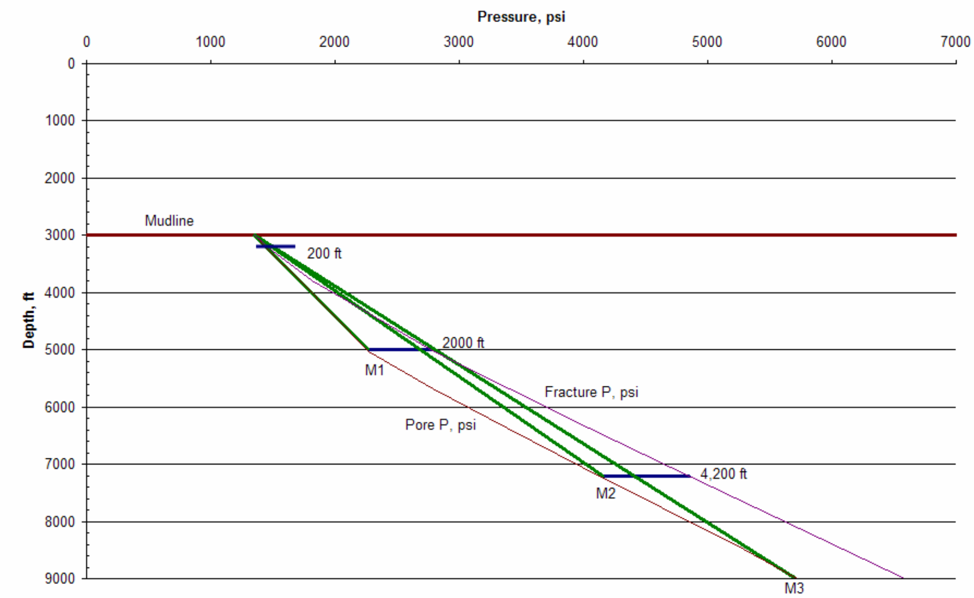

Fig. 20 - Graphical Casing Selection in 3000 ft Water Depth

Fig. 21 shows the graphical casing selection for 5,000 ft of Water Depth and **Fig. 22** shows the graphical casing selection for 10,000 ft of Water. It is important to note that while the actual pressures change with water depth, the pressure gradients remain the same. This means that the pore/fracture pressure window maintains a similar shape at all water depths and the selected casing points remain the same when depths are taken BML. The first casing seat at 200 ft BML is typical 36" Conductor Pipe that is usually jetted into the formation. The second casing seat at 2,000 ft BML is 30" Conductor Pipe and an 8.8 ppg mud must be used in order to reach this depth. The third and final top hole casing seat of 20" Conductor Pipe is at 4,200 ft BML and a 12.9 ppg mud is used to drill to this depth. For the purposes of this simulation top hole is defined as the first 6,000 ft BML. So, in order to drill to 6,000 ft BML, a mud weight of 14.0 ppg is used.

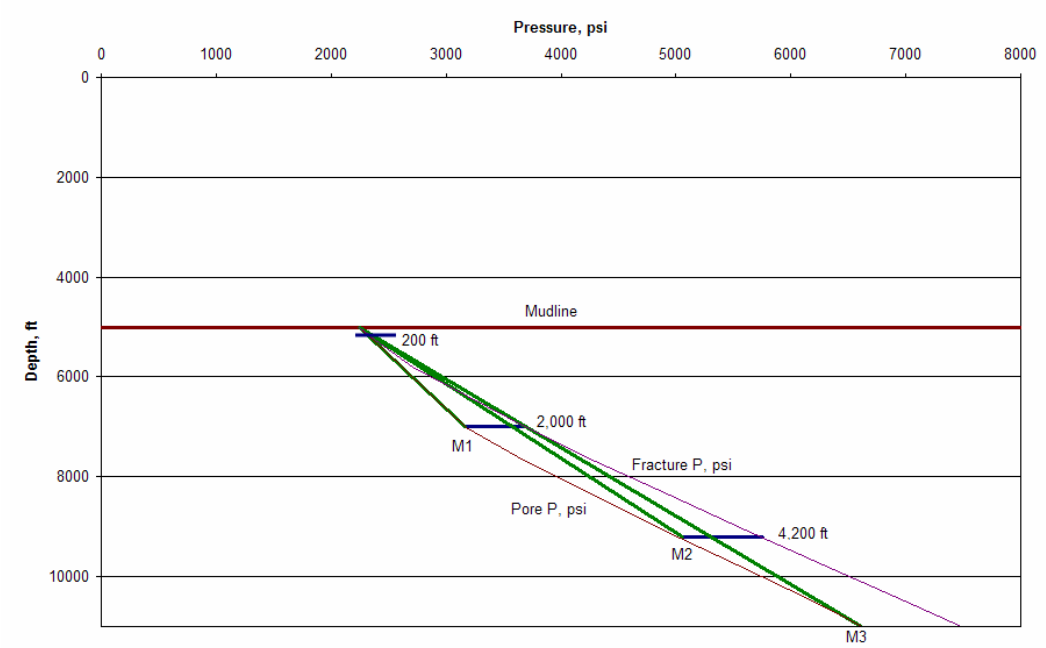

Fig. 21 - Graphical Casing Selection in 5000 ft Water Depth

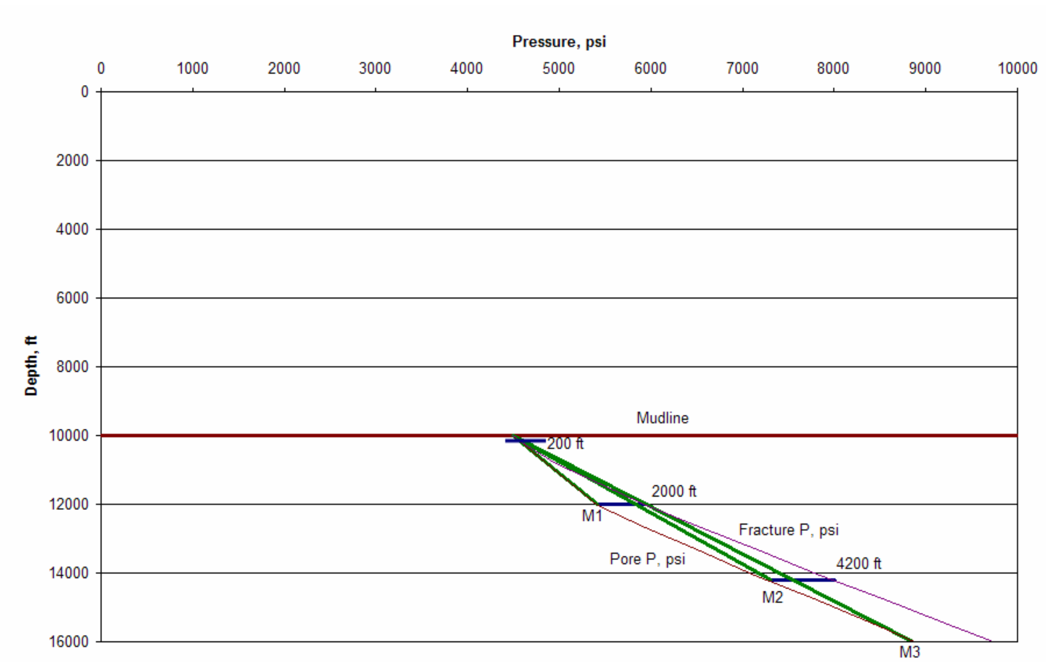

Fig. 22 - Graphical Casing Selection in 10,000 ft Water Depth

The resulting wellbore diagrams can be seen in **Fig. 23** for 3,000 ft Water depth, **Fig. 24** for 5,000 ft water depth and **Fig. 25** for 10,000 ft water depth. Again, notice how the depths BML of each casing are the same no matter what the water depth is.

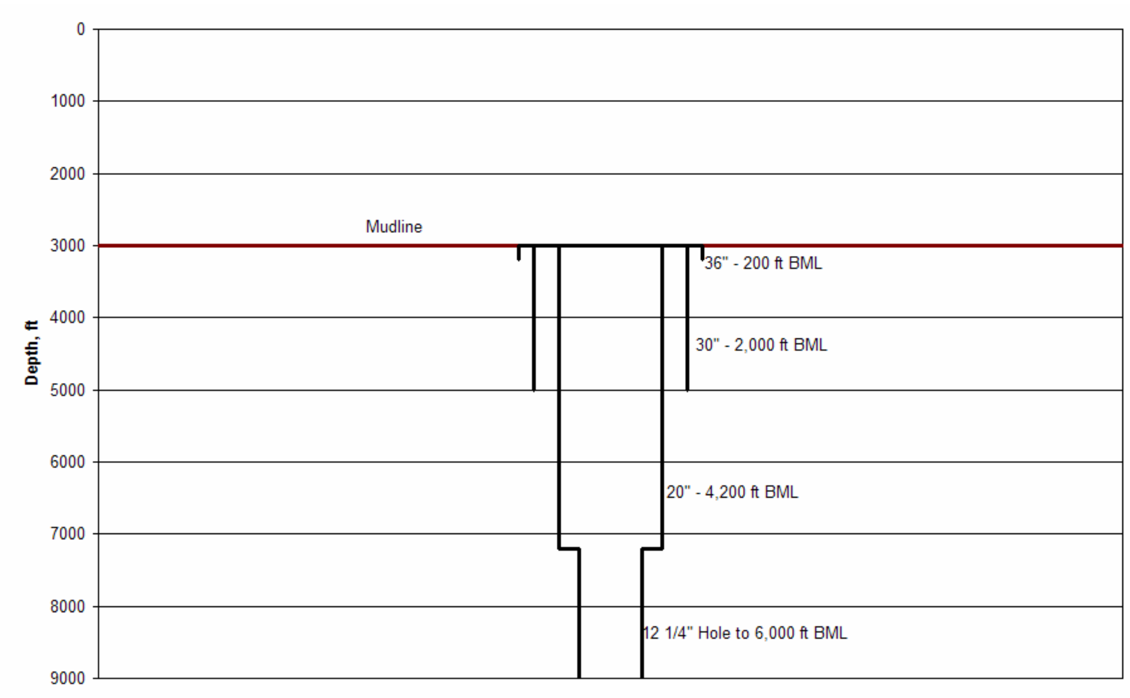

Fig. 23 - 3,000 ft Water Depth Wellbore Diagram

In this simulation set 18 different runs were completed, six for each water depth, and then two for each casing seat. For example, the first run for 3,000 ft water depth was with the casing set to 200 ft BML and the 12 ¼" pilot hole at 2,000 ft. The objective was to determine if the DGTHDS could drill to the depth of the next casing seat and successfully control a gas kick. Typically, the kick size was set at 50 bbl or the largest controllable kick based on the wellbore geometry. This was simulated with both

½ ppg formation overpressure and 1 ppg formation overpressure. Then the next casing seat was simulated by having 30” conductor pipe set to 2,000 ft BML and the 12 ¼”

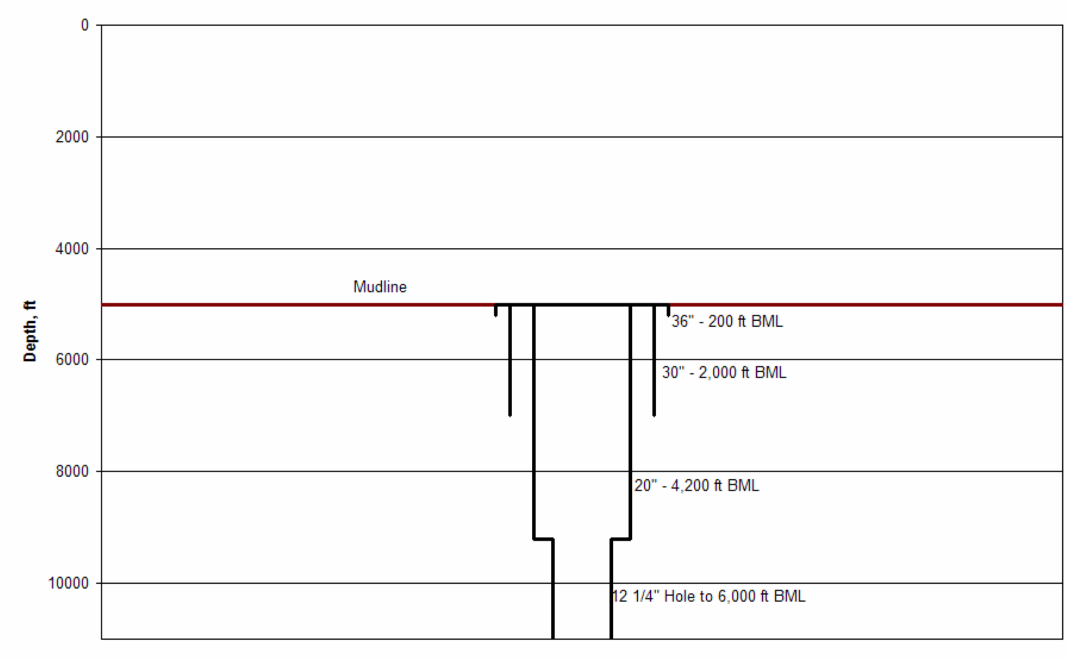

Fig. 24 - 5,000 ft Water Depth Wellbore Diagram

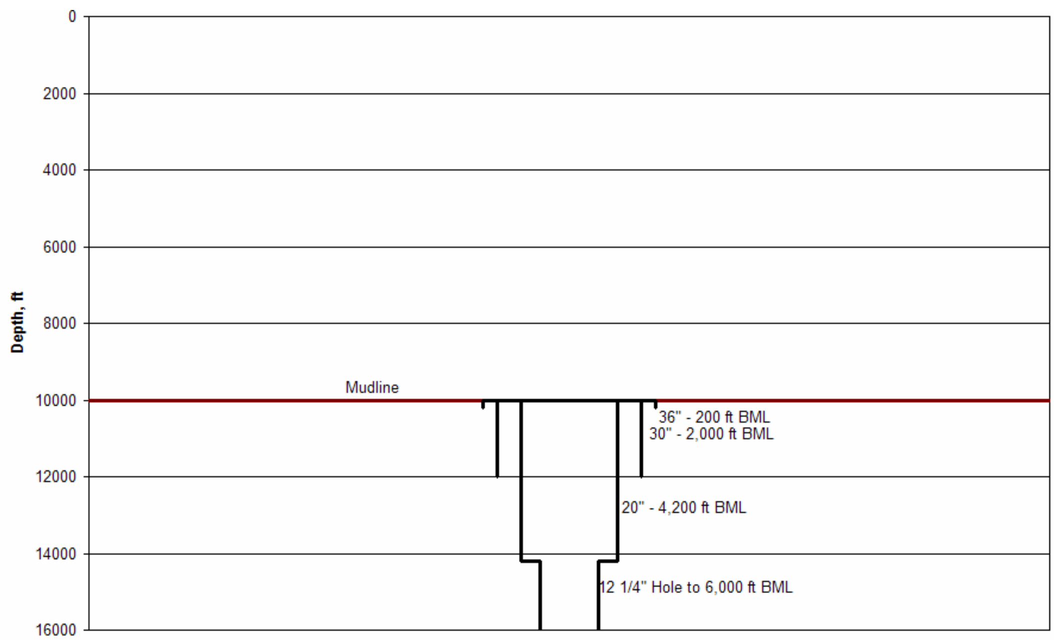

Fig. 25 - 10,000 ft Water Depth Wellbore Diagram

pilot hole drilled to a depth of 4,200 ft BML. Finally, the last test was to drill to 6,000 ft BML with the 20" conductor pipe set at 4,200 ft BML. This was then repeated for 5,000 ft water depth and 10,000 ft water depth. The variable parameters for each of the test runs can be seen in Table 2. The flowchart that describes the determination of run order can be seen in Appendix A, and the spreadsheets showing all of the input data for each run can be seen in Appendix D.

Table 2 - Variable Parameters of Simulation Set #2

Run #	Water Depth	Depth of Last Casing Seat	P&F PR #	Mud Weight	Mud Plastic Viscosity	Mud Yield Point Stress	Depth of 12 1/4" Pilot Hole BML	Formation Overpressure	Pit Gain Warning Level
	ft	ft BML		ppg	cp	lbf/100 sq. ft	ft	ppg	bbl
CS 1a	3,000	200	1	8.8	5	17	2,000	1	50
CS 1b	3,000	200	1	8.8	5	17	2,000	0.5	50
CS 2a	3,000	2,000	1	12.9	17.5	9	4,200	1	50
CS 2b	3,000	2,000	1	12.9	17.5	9	4,200	0.5	50
CS 3a	3,000	4,200	1	14	24	9	6,000	1	50
CS 3b	3,000	4,200	1	14	24	9	6,000	0.5	50
CS 4a	5,000	200	2	8.8	5	17	2,000	1	50
CS 4b	5,000	200	2	8.8	5	17	2,000	0.5	25
CS 5a	5,000	2,000	2	12.9	17.5	9	4,200	1	50
CS 5b	5,000	2,000	2	12.9	17.5	9	4,200	0.5	50
CS 6a	5,000	4,200	2	14	24	9	6,000	1	50
CS 6b	5,000	4,200	2	14	24	9	6,000	0.5	50
CS 7a	10,000	200	3	8.8	5	17	2,000	1	30
CS 7b	10,000	200	3	8.8	5	17	2,000	0.5	15
CS 8a	10,000	2,000	3	12.9	17.5	9	4,200	1	50
CS 8b	10,000	2,000	3	12.9	17.5	9	4,200	0.5	50
CS 9a	10,000	4,200	3	14	24	9	6,000	1	50
CS 9b	10,000	4,200	3	14	24	9	6,000	0.5	50

4.3 Simulation Procedure

Once all the simulation input data is entered the user returns to the main menu, seen previously in Fig. 13, to begin the kick simulation. The following procedure is followed to simulate a gas influx into the wellbore, prevent further influx, circulate the kick out of hole and weight up the mud and continue drilling. The kick simulation control panel can be seen in **Fig. 26**.

1. Increase Simulation Ratio to 10 times real time.
2. Increase Surface Pump rate to the standard pumping rate of 650 gpm.
3. Click Start Simulation Button

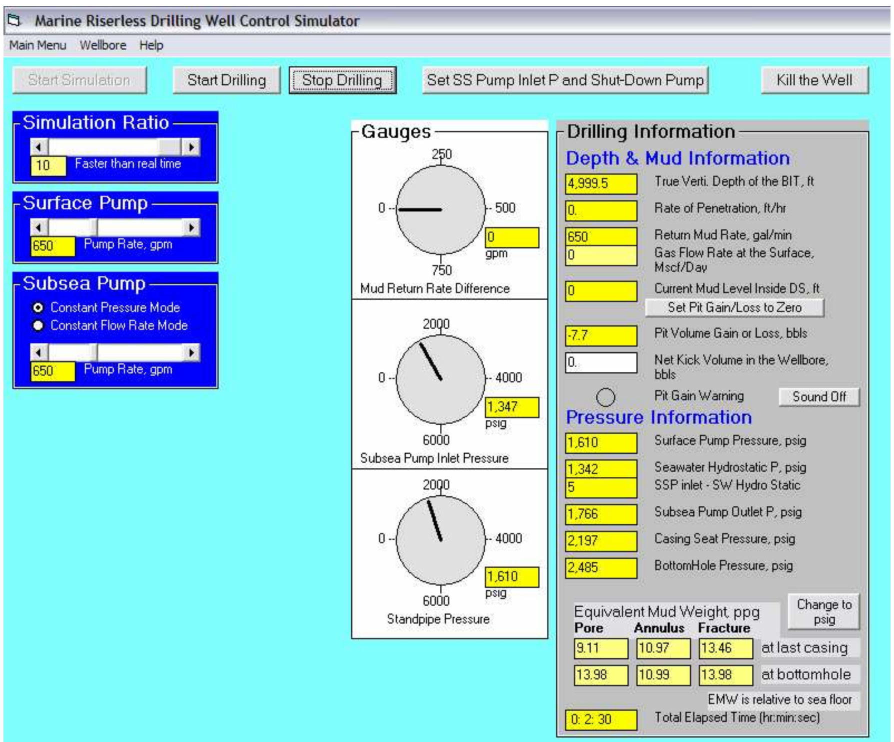

Fig. 26 - Kick Simulation Control Panel

4. Allow Drill String (DS) to fill with drilling fluid.
5. Once current mud level inside DS equals zero and the Subsea pump rate is constant at 650 gpm, set pit gain/loss to zero and then click start drilling button. (The simulator will begin simulating a gas kick momentarily).

6. As the gas kick enters the wellbore the subsea pump rate and the pit gain level warning will increase. While it is possible to detect the kick very rapidly in simulation, it is important to simulate actual drilling methods by waiting for the pit gain warning to go off when the pit level is increased by the previously specified volume. The wellbore schematic also illustrates the incoming kick as seen in **Fig. 27**.

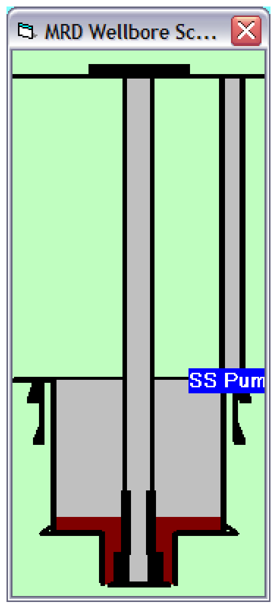

Fig. 27 - Illustration of Wellbore Showing Gas Kick Influx

7. Once the pit gain warning goes off, begin the "Modified Driller's Method". The pit gain warning level will flash as seen in **Fig. 28**. Change the Subsea pump to constant pumping rate mode and return the pumping rate to 650 gpm. This creates the necessary backpressure to prevent further influx into the wellbore.

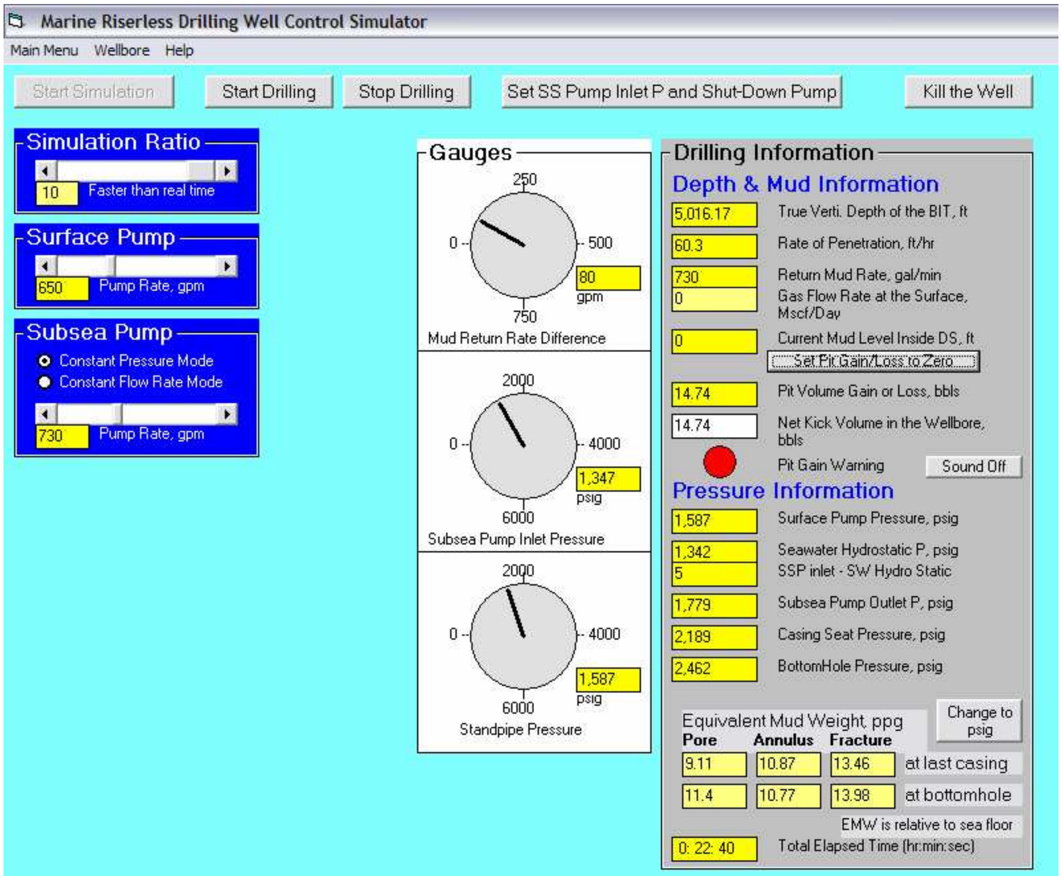

Fig. 28 - Flashing Pit Gain Warning Alarm

8. Monitor the annulus and formation pressures. When these pressures are balanced the simulated influx will be stopped and the user can simulate perfect well control by clicking the “Kill the Well” Button. (If the user does not properly prevent the influx a blowout can result and the simulator will return a warning box like what is shown in **Fig. 29**.

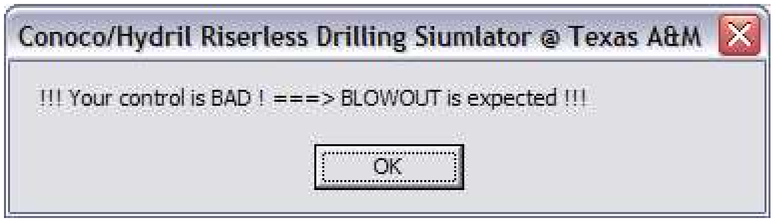

Fig. 29 - Simulator Blowout Warning Box

9. Once the “Kill the Well” button has been clicked the simulator allows the user to circulate the kick manually or with perfect control. For the purposes of testing the well control limits of the dual gradient system, perfect well control is selected.
10. The user is taken to a new screen where the user then selects a simulation acceleration ratio of 80 times that of real time. Then from the main menu the user selects: show wellbore and start circulation.
11. The simulator controls the pumping rate of the subsea pump to maintain perfect pressure balance between the formation and the annulus to prevent further influx while circulating the kick out of the wellbore.

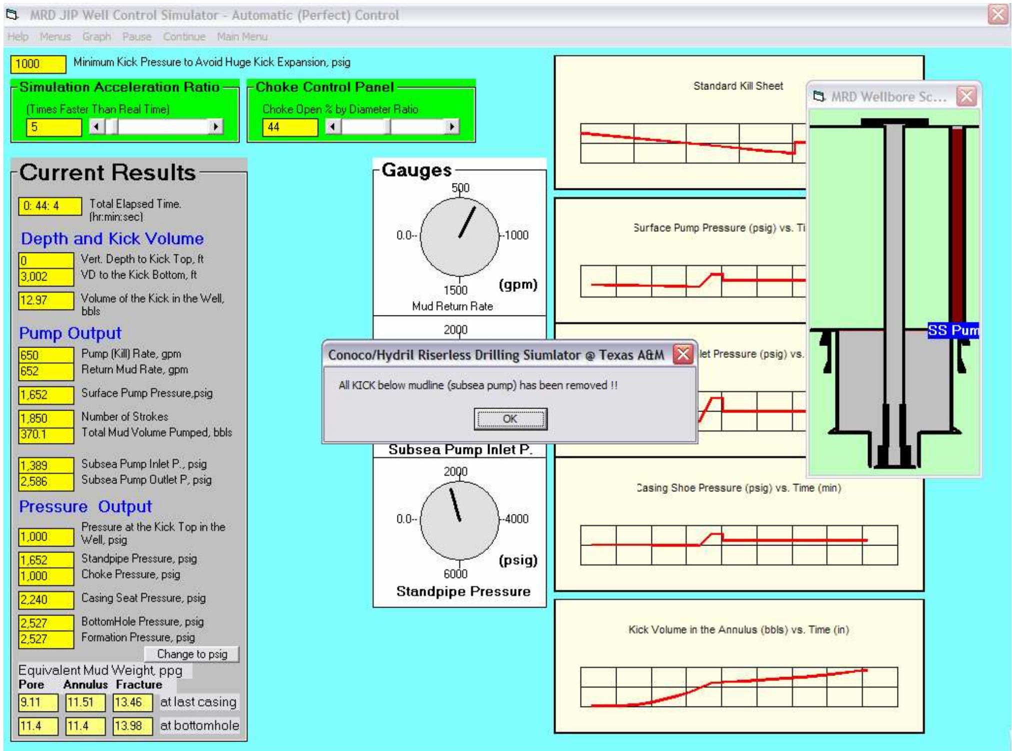

Fig. 30 - Simulator Kick Circulation Screen

12. Once the kick has been removed below the mudline the user will receive a message as seen in **Fig. 30**. The simulator then continues circulating the kick until the kick is completely removed from the system. Then the simulator shows an automatic circulation of kill weight mud to ensure the prevention of more gas influxes.

13. Now the user can continue on to analyze the data created by the simulator.

4.4 Simulation Results Analysis Procedure

Finally, the resulting data from the simulator is analyzed to determine if the pressure at the casing seat pressure and the pressure at the top of the kick caused formation fracturing, or damage to the casing seat. In **Fig. 31** you can see the results data from the simulator in graphical form. Aside from the pressure at the top of the kick the user can also track: standpipe pressure, choke pressure, casing shoe pressure, subsea inlet pump pressure, subsea outlet pump pressure, surface pump pressure, the volume of mud pumped, the mud and gas return rates at the rig floor, choke opening and the kick pressure, height, volume, and influx rate at all times during the simulation.

Fig. 31 - Simulation Results in Graphical Form

All of this data is important to the driller. The casing shoe pressure, subsea pump inlet and outlet pressures help to determine if the equipment pressure ratings have been exceeded and the mud and gas production determine necessary surface handling capacities. Most importantly, however, the simulation returns information on the kick as it progresses through the wellbore. You can expand each of the different plots to look at the graph zoomed in. **Fig. 32** shows the zoomed in version of kick pressure versus time.

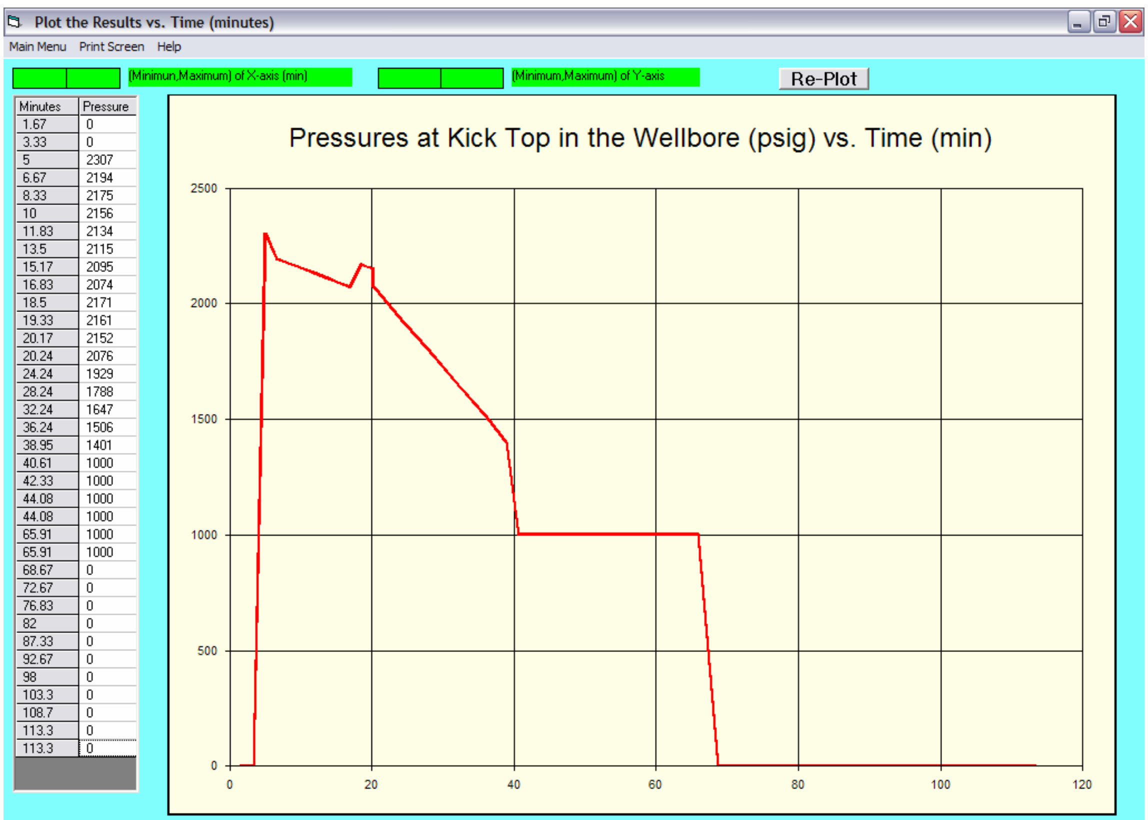

Fig. 32 - Zoomed in Graph of Pressure @ Top of Kick versus Time

The data can also be exported in table format. This information is important, because the pressure at the top of the kick can be plotted versus the location, within the wellbore, the top of the kick. Putting this plot together with a plot of formation pore and fracture pressures, the user can determine if circulating the kick resulted in formation fracture and lost circulation. An example of this plot can be seen in **Fig. 33**. In this example case, from simulation set #1, the sea water depth is 5,000 ft and the 30” conductor pipe was set 1,500 ft BML.

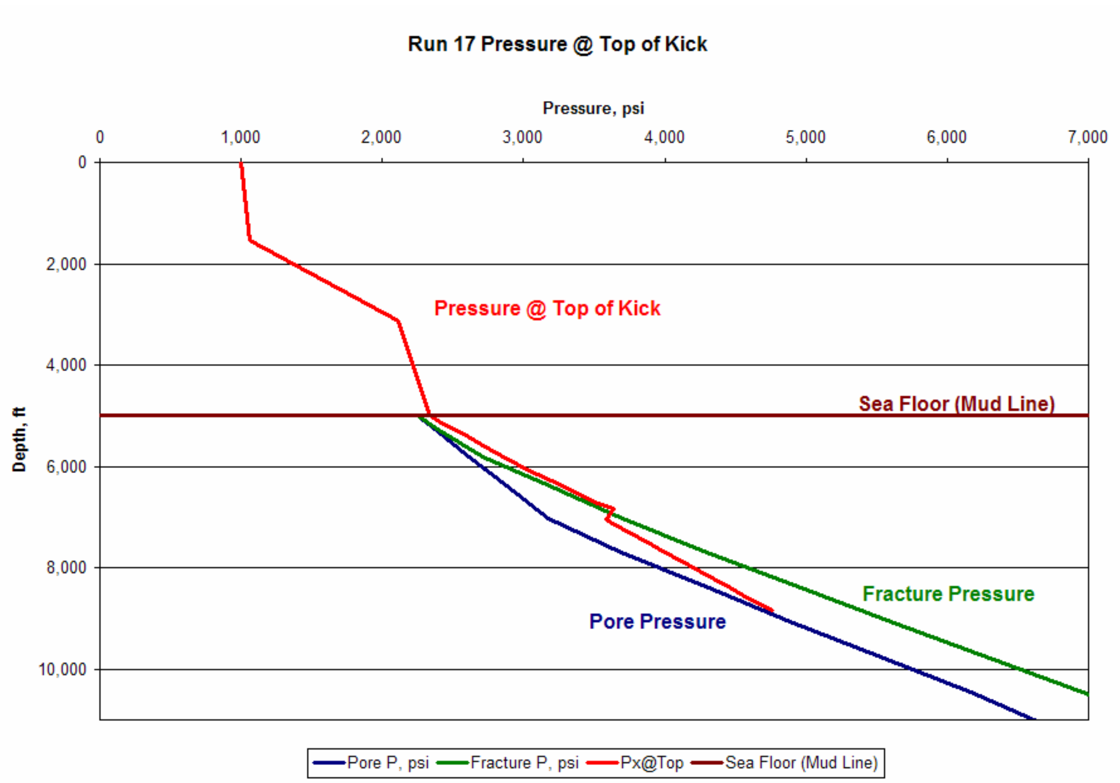

Fig. 33 - Kick Pressure, Pore Pressure and Fracture Pressure Plotted versus Depth

The pressure at the top of the kick is indicated by the red line, the pore pressure by the blue line and the fracture pressure by the green line. If the pressure at the top of the kick increases above the formation fracture pressure below the conductor pipe, the formation will fracture and an underground blowout could be experienced. This graph clearly shows that the pressure at the top of the kick increases above the fracture pressure at approximately 1,800 ft BML. In this case, the conductor pipe (set at 1,500 ft BML) was not set deep enough to prevent formation fracturing.

Also a consideration, are the pressures within the wellbore and at the subsea pump. These pressures are also tracked by the simulator and can be plotted versus time, as shown in **Fig. 34**. The casing seat pressure, Bottom Hole Pressure (BHP), subsea pump inlet pressure and stand pipe pressure (SPP), basically follow the same pattern. These regions are all impacted on before the mud enters the subsea pump. The subsea pump outlet pressure, however, is a pressure region located after the mud passes through the subsea pump. The four pressures in the region before the subsea pump begin to decrease as the kick enters the wellbore and the subsea pump rate increases to compensate. At the same time, a slight increase in pump outlet pressure can also be seen. In this example, at approximately 21 minutes, the kick is detected and the subsea pump rate is decreased to pre-kick rate. This is shown by the abrupt increase in casing pressure, BHP, drillpipe pressure and subsea pump inlet pressure. (The abrupt up and down spike is caused by the simulator, but would not typically be seen in the actual wellbore conditions.) Then as the kick is circulated these pressures become level. The subsea pump outlet pressure, however, remains constant until the point when the kick is circulated through the subsea pump and the pressure increases. Which, in this example, occurs at approximately 45 minutes.

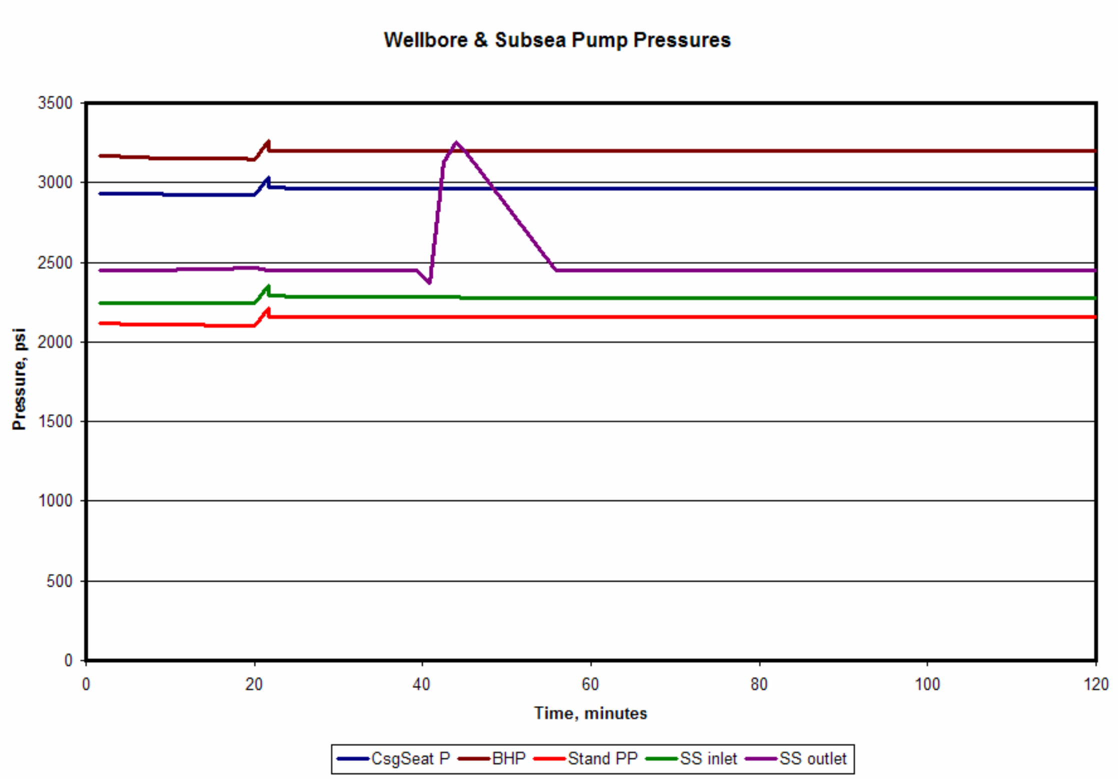

Fig. 34 - Wellbore and Subsea Pump Pressures Example Graph

This data is important, because it is important to track the pressure within the wellbore, not just the pressure at the top of the kick, to determine if there are any other potentially hazardous situations occurring within the system such as if the casing seat pressure exceeds the formation fracture pressure at the casing seat depth and an underground blowout occurs.

4.5 Simulation Results Analysis

Simulation Set #2 was extremely necessary upon the analysis of Simulation Set #1. It became obvious that an arbitrary selection of conductor pipe seat depth was unacceptable for the DGTHDS and the drilling program needs to be customized based on the P&F PR.

4.5.1 Simulation Results Analysis – Simulation Set #1

It became evident upon examining the results that the drilling depth BML had more of an impact on whether a simulation resulted in formation fracture than sea water depth. Runs 1 through 12 were executed in 3,000 ft of sea water at varying drilling depths of 2,000, 4,000 and 6,000 ft BML. Runs 1 through 4 (2,000 ft BML) did not result in fracturing of the formation. The casing seat at 1,500 ft BML was deep enough to prevent formation fracture. However, Runs 5 through 12 (4,000 and 6,000ft BML) all resulted in a fractured formation. The reason is that the heavier mud weights, required to maintain BHP above formation pore pressure, fractured the formation at shallower depths, and the conductor pipe was not set deep enough to prevent this formation fracture. These graphs for each run, similar to the example shown in Fig. 33 can be seen in Appendix E. **Fig. 35** shows the pressure at the top of the kick in Run 4. In this case the kick was successfully circulated without fracturing the formation.

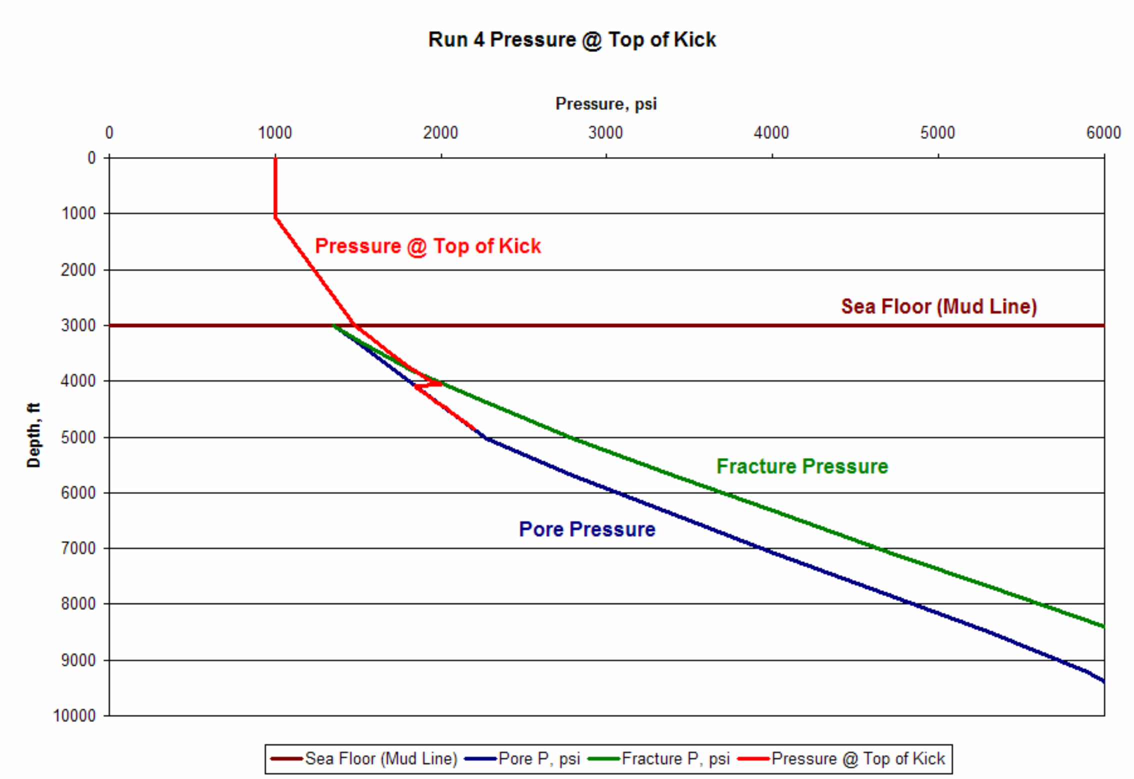

Fig. 35 - Pressure at the Top of the Kick in Run 4

Runs 13 through 24 (5,000ft of sea water) had the same results as Runs 1 through 12. Again, Runs 13 through 16 (2,000 ft BML) did not result in fracturing of the formation. Again, however, Runs 17 through 24 (4,000 and 6,000 ft BML) all resulted in fractured formation. **Fig. 36** shows how, in Run 24, the kick pressure, shown in red, rose above the fracture pressure, shown in green, below the conductor pipe seat at 1,500 ft BML. This signifies that the formation was fractured and an underground blowout would likely be the result if wellbore is not plugged rapidly. The rest of these graphs can be seen in Appendix E.

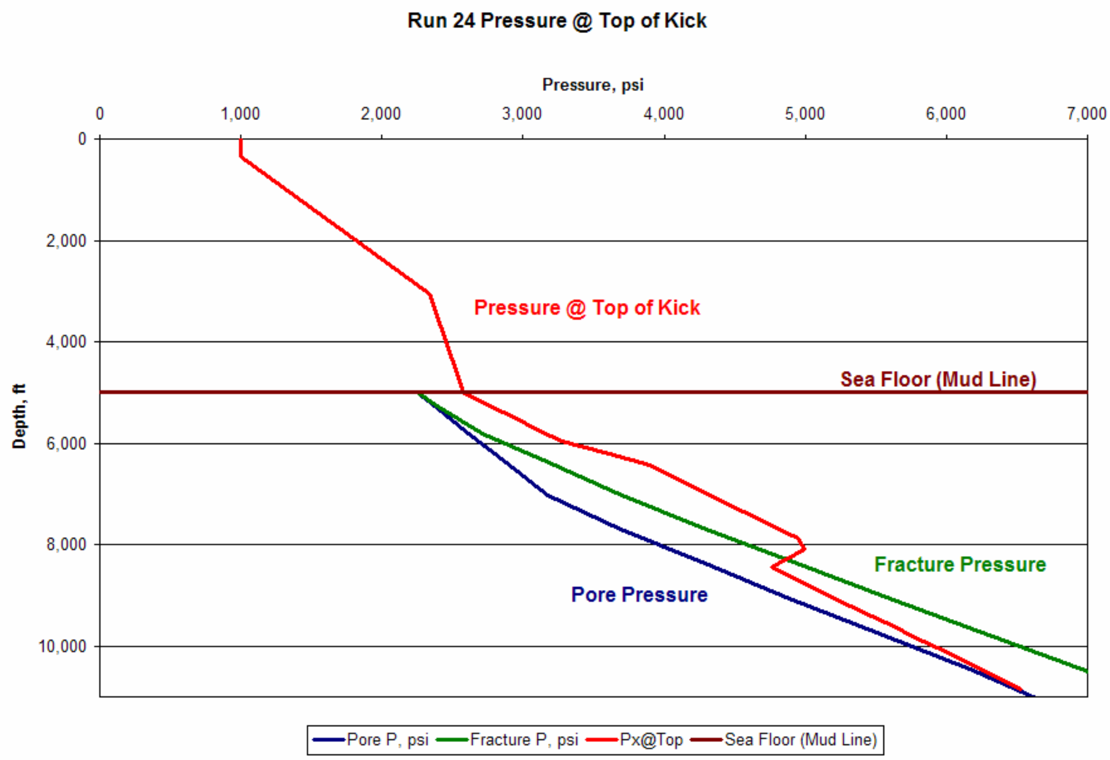

Fig. 36 – Pressure at the Top of the Kick in Run 24

Runs 25 through 36 were performed in 10,000 ft of sea water and had the same results as Runs 1 through 24. When the drilling depth was 2,000 ft BML (Runs 25 through 28), all kicks were successfully circulated. However, when the drilling depth was deeper than 2,000 ft BML (Runs 29 through 36), the formation was fractured during kick circulation. These graphs can be seen in Appendix E. Ultimately Simulation Set #1 resulted in the obvious conclusion that casing needs to be set deeper and more often than only at 1,500 ft BML.

4.5.2 Simulation Results Analysis – Simulation Set #2

Since the main purpose of the project is simply to prove that the DGTHDS is more reliable at circulating shallow hazards than the "Pump and Dump" method, it is acceptable to set casing more often than only at 1,500 ft BML. In a conventional "Pump and Dump" system, conductor pipe and surface casing would be set often, and usually more frequently than what was designed in the original drilling program. So, the key to a successful Simulation Set #2 was to determine the well control limits of the DGTHDS when a proper casing program is in place. Runs CS1a through CS3b were performed in 3,000 ft of sea water. In every case the kick of 50 bbl was successfully circulated above the conductor pipe before the pressure at the top of the kick increased above the formation fracture pressure. Runs CS3a and CS3b can be seen in **Fig. 37**.

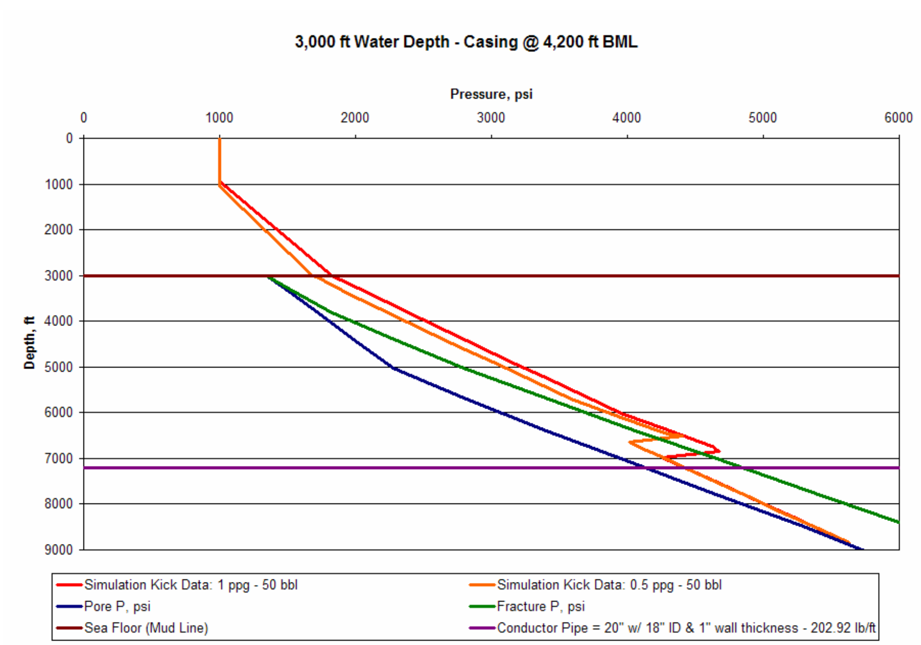

Fig. 37 - Pressure at the Top of the Kick in Runs CS3a and CS3b

In Runs CS4a through CS6b (5,000 ft of Sea Water) also resulted in successful kick circulation. A significant point is, in the shallow BML depths of Run CS4b the system was not able to successfully circulate a kick larger than 25 bbl in a 0.5 ppg over pressured formation. However, a 50 bbl kick was successfully circulated when the formation was 1 ppg overpressure. This can be seen in **Fig. 38** and the reason a smaller kick size in a 0.5 ppg over pressure formation results in a simulated blowout and a larger kick size in a 1.0 ppg over pressure formation does not, is that the kick in the 0.5 ppg formation over pressure kick enters the wellbore slower than the 1.0 ppg formation over pressure kick. This means that first bubble of the kick is circulated higher within the wellbore, in the same amount of time, even though the actual kick size is smaller. This causes the simulator to react as though the user did not properly detect the kick or take action, and a surface blowout is simulated as an expectation. This is a topic for future research that may lead the primary investigator to change some of the code in the riserless drilling simulator created by Dr. Choe.

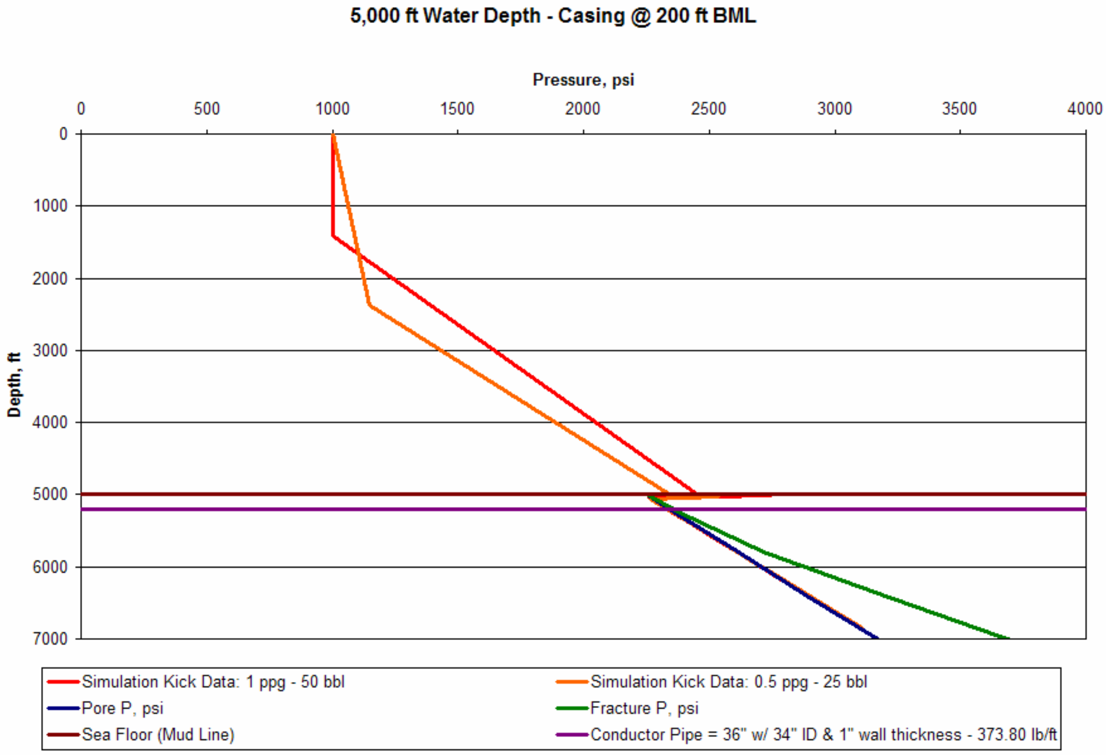

Fig. 38 - Pressure at the Top of the Kick in Runs CS4a and CS4b

In Runs CS7a through CS9b a similar result occurred. All kicks were successfully circulated without formation fracturing, but again the largest kicks that could be circulated without formation fracturing, in drilling depths of 2,000 ft BML, Runs CS7a and CS7b, were 30 bbl in 1 ppg formation overpressure and 15 bbl in a 0.5 ppg formation overpressure. In deeper BML drilling depths, Runs CS8a through CS9b, 50 bbl kicks were successfully circulated without formation fracturing. The successful circulation of a kick at 6,000 ft BML in 10,000 ft of seawater can be seen in **Fig. 39**.

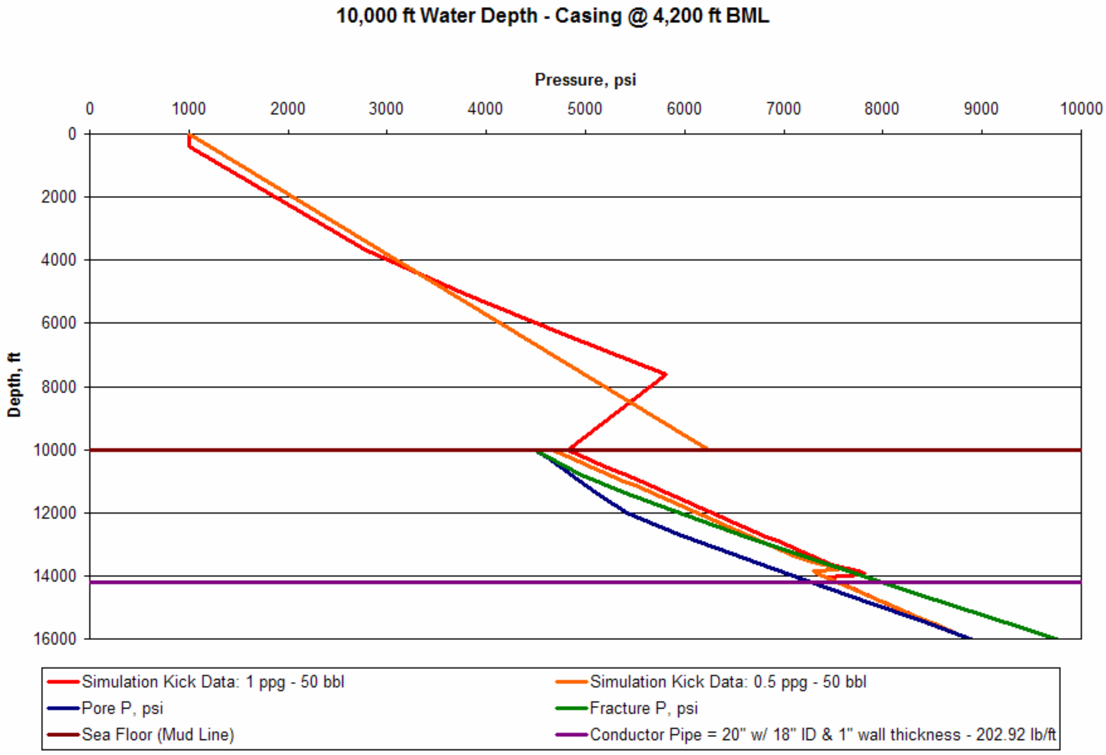

Fig. 39 - Pressure at the Top of the Kick in Runs CS9a and CS9b

The next step is to analyze the casing seat pressure as a method of double checking that the casing seat pressure does not rise above formation fracture pressure at the casing seat depth. Casing seat pressure data from the simulator is exported and plotted, along with the formation fracture pressure at casing seat depth. **Fig. 40** shows the casing seat pressure of run CS7 with respect to time. On the secondary y-axis the depth at the top of the kick, the casing seat depth and sea floor depth is plotted so that correlations between kick location and casing seat pressure can be drawn. In this run it can be seen that there is a jump in the casing seat pressure. This is a result of when the subsea mud pump rate is slowed to increase annulus pressure and prevent the influx of more reservoir fluids.

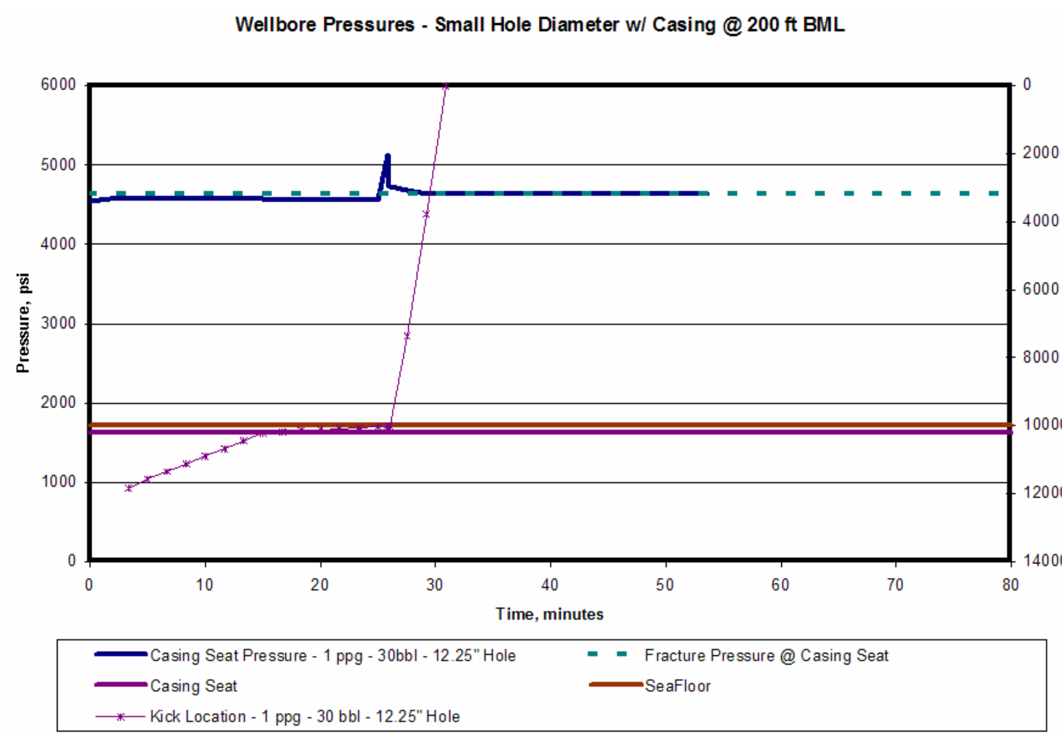

Fig. 40 - Casing Seat Pressure in Run CS7

Even once the casing seat pressure stabilizes, it is still very close to formation fracture pressure. This is a concern and a better understanding of why this occurs is a good idea for future research into the implementation of a DGTHDS. Similar results can be seen in **Fig. 41** and **Fig. 42** (results from Runs CS8 and CS9). Is this simply a glitch within the simulator? Does casing need to be set even more often? Would a smaller kick size have the same high pressure? These are all questions that need to be answered in order to fully understand a DGTHDS.

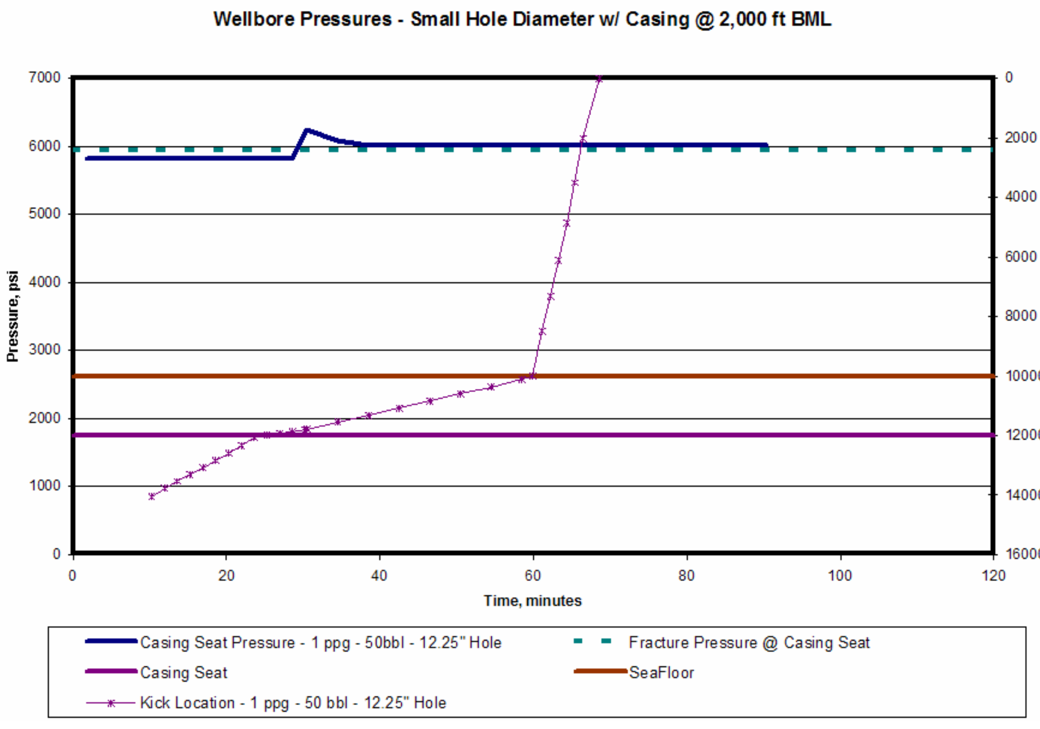

Fig. 41 - Casing Seat Pressure in Run CS8

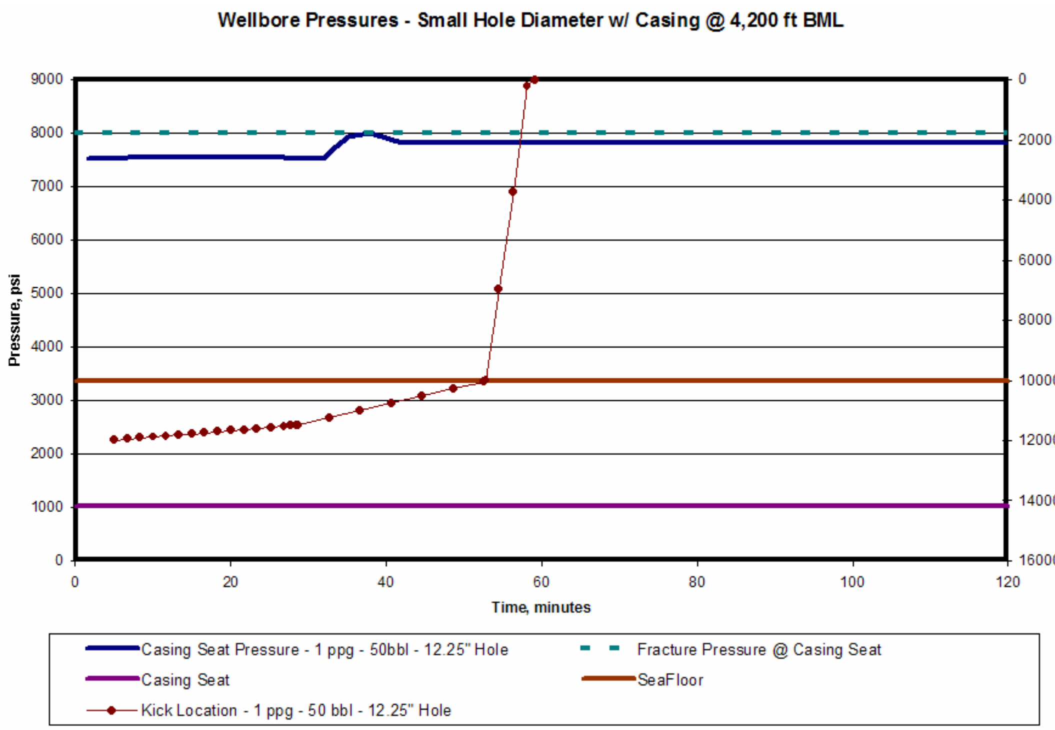

Fig. 42 - Casing Seat Pressure in Run CS9

Finally, it is apparent from Simulation Set #2 that when a proper casing program is designed and in place kicks can be rapidly detected and circulated out of the wellbore. There are still uncertainties within the system that need to be further addressed. An important point to note is that 50 bbl kicks are unlikely because in the DGTHDS kick detection happens rapidly and with a properly trained drilling crew most kicks should be detected and the "Modified Driller's Method" will begin well before the kick size reaches even 10 bbl.

Finally, a significant observation is that Simulation Set #2 was performed entirely with 12 ¼" pilot hole below the last conductor pipe seat. This is the current industry standard, because it is easy to pump cement into a 12 ¼" pilot hole when a kick is encountered. However, in this system the larger the hole diameter the less impact the kick has on wellbore pressures, and the easier the kick is to circulate. Conventionally, a smaller pilot hole resulted in safer drilling operations but, in the DGTHDS a larger pilot hole may result in safer drilling operations. This could save expensive rig time that is required to drill a pilot hole to the next casing depth and then ream the hole out to casing OD size.

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS FOR THE FUTURE OF DUAL GRADIENT TECHNOLOGY

5.1 Conclusions

Dual gradient drilling technology is not beyond our reach. This technology has been designed, engineered and field tested for feasibility. This technology has been successfully applied to the top hole portion of a wellbore in a shallow water environment and in a deepwater environment after conductor and surface casing have been set. The riserless drilling simulator indicates that applying dual gradient technology to top hole drilling, when used in conjunction with a proper casing program, successfully navigates the narrow window between formation pore pressure and formation fracture pressure. The results of simulation also leads to the conclusion that the dual gradient technology applies safe well control methods while drilling the top hole portion and can control all three major shallow hazards. Riserless Dual Gradient Top Hole Drilling results in:

- Rapid and accurate kick detection
- Safe Well Control Procedures
- Successful pore/fracture pressure window navigation
- Control over pressured shallow gas zones

- Control over shallow water flows
- Control over dissociating methane hydrates
- Improved casing seats and wellbore integrity
- Reduced number of casing strings
- Reduced overall costs
- Prevention of methane hydrate formation
- Reduced environmental impact.

The advantages of the system far outweigh the reluctance of the industry to implementing a new technology. The key is to continue to overcome the industries resistance to the new technology by education, training and gradual implementation of the DGTHDS into conventional practices.

Dual gradient technology still has uncharted territory, however, a DGTHDS has already been proven to be substantially safer and more reliable than the current “Pump and Dump” technology. The remaining questions need only be answered to streamline the DGTHDS. AGR has proven that a DGTHDS is the key to improving top hole drilling in shallow water depths. As AGR adapts their technology to conquer deeper water depths and academic research continues to improve the design of a DGTHDS for deepwater, a DGTHDS will cease to be a technology of the future and become the new industry standard that everyone strives to improve.

5.2 Recommendations for the Future of Top Hole Dual Gradient Drilling

While this technology still gives every indication of being an improvement over the current top hole drilling practice of “Pump and Dump”, there are still some uncertainties regarding the DGTHDS. There are three main questions that still remain to be answered. The first, as briefly discusses in Chapter IV, is how does the location, in the annulus, of the first bubble of the kick impact on annulus pressures and kick circulation. Is the simulator, originally created for training purposes, reacting from a human error point of view (meaning a lack of response results in a blowout) or from a technical point of view (meaning a bubble at shallow depths within the annulus will, in reality, result in a surface blowout). A new research project may be launched to get deep into the programming of the simulator to find the answer to this question.

The second question is regarding the tracking of the casing seat pressure. Will setting casing more often and at shallower depths BML keep the casing seat pressure below formation fracture pressure? Will smaller kick sizes result in lower casing seat pressure? Which brings us to the third and perhaps most interesting question? How does the pilot hole size affect the kick height and size and annulus pressures?

Several simulations were ran in 10,000 ft of sea water, but instead of using the standard 12.25” pilot hole, a hole the size of the next casing OD size was drilled below the last casing seat. The runs were done in a formation of 1.0 ppg over pressure, and the kick size was always as large as possible. The results were quite interesting and can be seen in **Fig. 43, 44** and **45**.

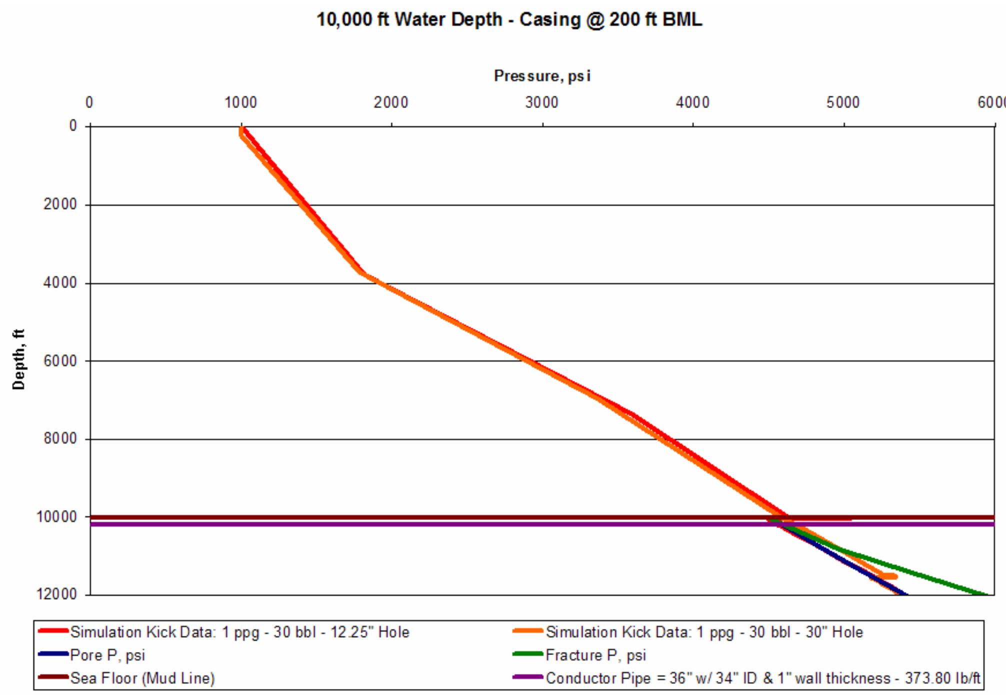

Fig. 43 - Larger Hole Diameter than Run CS7

In Fig. 43 the pressure at the top of the kick in the simulation with the larger size pilot hole can be seen in orange. The run with the conventional pilot size hole of 12.25" can be tracked in red. In the case of the larger hole diameter, the pressure at the top of the kick rises above formation fracture pressure before reaching the conductor pipe set at 200 ft BML. This is likely because even though the kick size is the same, the larger hole size reduces the total height of the kick. This means that when the subsea mud pump is slowed down to prevent additional influx the top of the kick is still a lot deeper than the last casing seat. Then as the kick is circulated, the pressure at the top of the kick can easily rise about formation fracture pressure. Which again leads to the question… Does casing need to be set more often and conservatively when dealing in a deepwater environment? Fig. 44 and Fig. 45 show the results of larger hole diameter when casing is set at 2,000 ft BML and 4,200 ft BML, respectively. The results are similar to those shown in Fig. 43. However in Fig. 45 the difference between in the pressure at the top of the kick in the 12.25" pilot hole and the larger pilot hole is minimal because the difference (from 12.25" to 17.5") between hole diameter is minimal. To more fully understand the limitation of the DGTHDS more research into the effect of a larger pilot hole size is necessary.

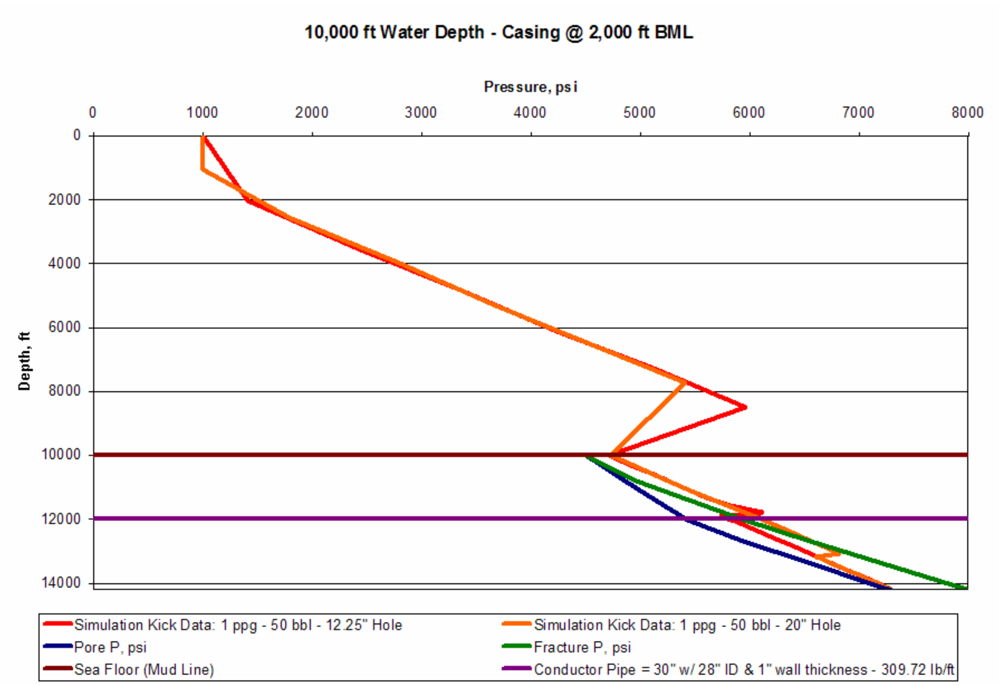

Fig. 44 - Larger Hole Diameter than Run CS8

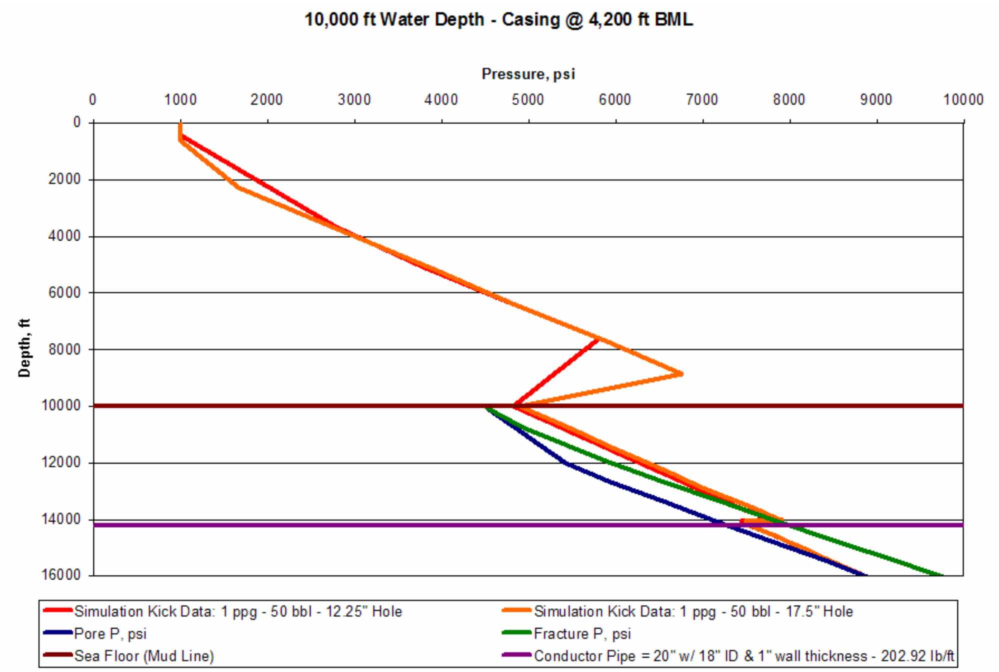

Fig. 45 - Larger Hole Diameter than Run CS9

To answer the questions regarding: the effect of bubble height within the well, the accuracy of the simulator's casing seat pressure predictions and the possible impact of larger pilot hole sizes, the next step is to design and field test a system that can be applied to drilling the top hole portion of a wellbore in a deepwater environment. In a continuation of the OTRC / MMS project "Application of Dual Gradient Technology to Top Hole Drilling", the top hole dual gradient equipment should be designed, constructed, commissioned and field tested. It is imperative that the industry be shown how beneficial the application of dual gradient technology to top hole drilling can be.

Dual gradient technology promises to: improve safety and well control while drilling, decrease costs, improve wellbore quality and reduce environmental impact.

Even so, developing a new technology can be expensive and difficult to implement. The step, that is paramount to implementing dual gradient technology into commercial use, is to convince the industry end users (operators and service companies alike) that dual gradient technology will significantly improve deepwater drilling operations through education and training. This can best be done is small steps, by focusing on improving one part of the current technology at a time. In this manner top hole dual gradient drilling will be implemented slowly, but seamlessly and to the advantage of everyone involved.

NOMENCLATURE

AGR	AGR Ability Group
bbl	Barrels
BHP	Bottom Hole Pressure
BML	Below Mud Line
BOP	Blow Out Preventer
cp	centipoises
DOE	Department of Energy
DGTHDS	Dual Gradient Top Hole Drilling System
DS	Drill String
DSV	Drill String Valve
E&P	Exploration and Production
ºF	Degrees Fahrenheit
ft	Feet
gpm	Gallons per Minute (gallons/minute)
HSP	Hydrostatic Pressure
IADC	International Association of Drilling Contractors
ID	inner diameter
JIP	Joint Industry Project
lbf/100 sq.ft	Pounds of Force per 100 square feet

MC	Mississippi Canyon
MMS	Minerals Management Service
MPD	Managed Pressure Drilling
NSF	National Science Foundation
OD	Outer Diameter
OTRC	Offshore Technology Research Center
P&F PR	Pore and Fracture Pressure Regime
ppg	Pounds per Gallon (lb/gal)
psi	Pounds per Square Inch (lb/in^2)
RMR	Riserless Mud Return
SPP	Standpipe Pressure
SSMLDJIP	SubSea MudLift Drilling Joint Industry Project
SRD	SubSea Rotating Diverter
TD	Total Depth

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APPENDIX A

SIMULATOR INPUT FLOWCHARTS

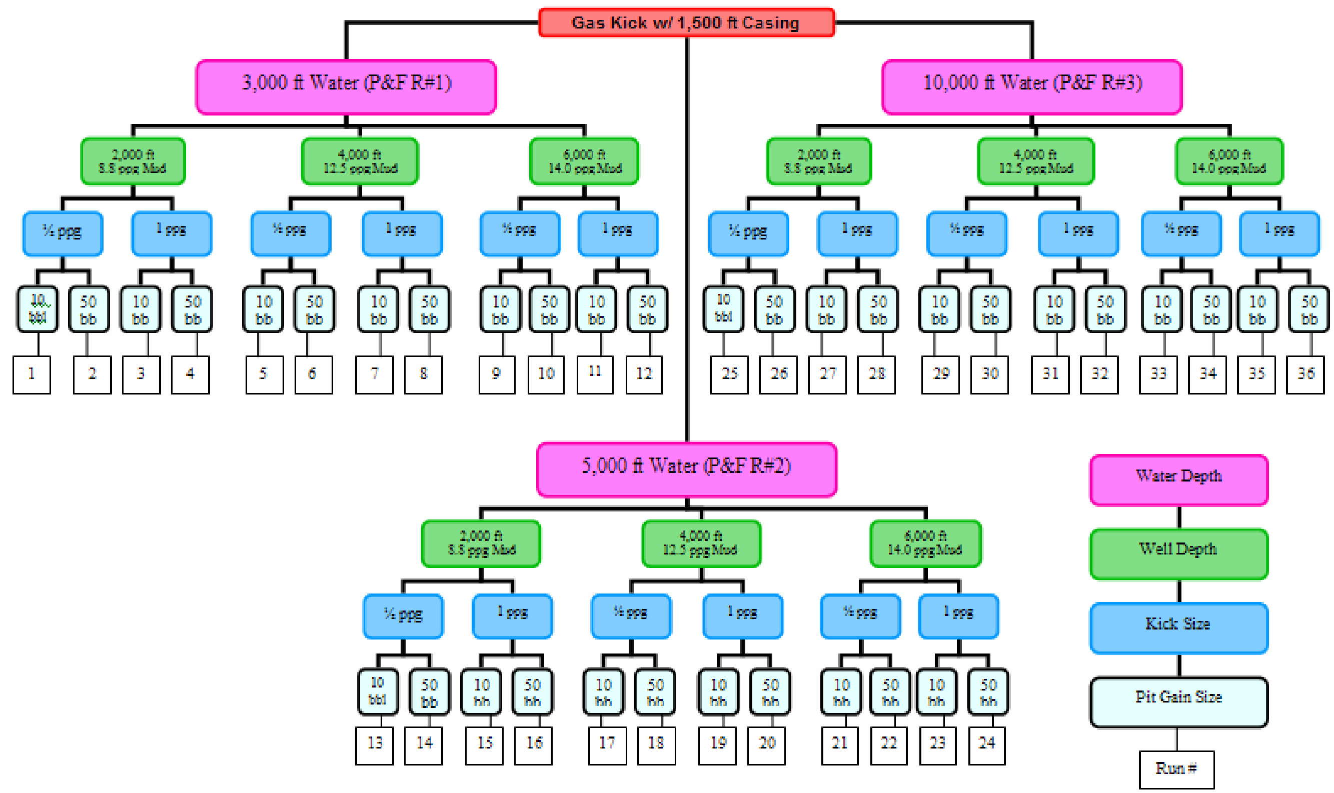

Fig. A1 – Simulation Set #1 Flowchart

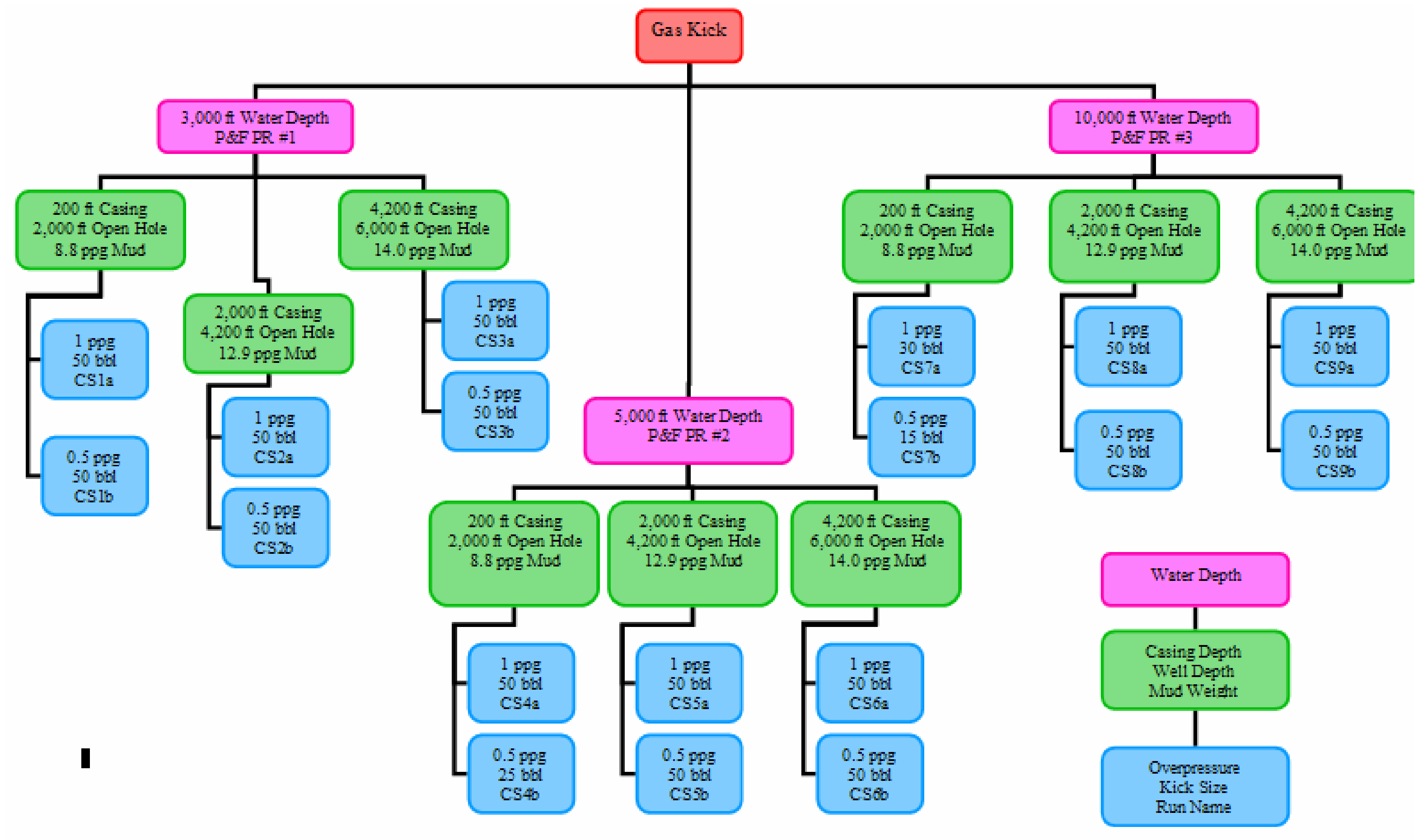

Fig. A2 – Simulation Set #2 Flowchart

APPENDIX B

PORE/FRACTURE PRESSURE REGIMES

Table B1 - P&F R#1 – 3,000 ft Water Depth

Pore & Fracture Pressures:		
Depth, SubSea, ft	Pore P, psi	Fracture P, psi
3,000	1,349	1,349
3,260	1,468	1,488
3,804	1,716	1,815
4,393	1,985	2,287
5,025	2,276	2,798
5,686	2,794	3,401
6,364	3,385	4,041
7,055	3,989	4,699
7,760	4,631	5,382
8,478	5,291	6,085
9,213	5,896	6,789
9,974	6,358	7,473
10,763	6,948	8,222
11,573	7,634	9,021
12,402	8,353	9,851
13,253	9,119	10,718
14,131	9,850	11,602
15,045	10,503	12,498
15,996	11,303	13,475
16,983	11,982	14,452
18,000	12,959	15,552
19,037	13,819	16,644
20,106	14,546	17,732
21,215	15,164	18,831
22,373	15,653	19,945
23,589	15,996	21,078
24,875	16,059	22,201
26,244	15,965	23,365
27,667	17,136	24,977
29,098	18,995	26,822
30,524	20,671	28,627

Table B2 - P&F R#2 – 5,000 ft Water Depth

Pore & Fracture Pressures:		
Depth, SubSea, ft	Pore P, psi	Fracture P, psi
5,000	2,249	2,249
5,260	2,368	2,387
5,804	2,615	2,715
6,393	2,884	3,187
7,025	3,176	3,698
7,686	3,693	4,300
8,364	4,285	4,941
9,055	4,889	5,598
9,760	5,531	6,282
10,478	6,191	6,985
11,213	6,796	7,688
11,974	7,258	8,373
12,763	7,848	9,122
13,573	8,534	9,921
14,402	9,252	10,751
15,253	10,018	11,618
16,131	10,749	12,501
17,045	11,402	13,397
17,996	12,203	14,374
18,983	12,882	15,352
20,000	13,859	16,452
21,037	14,719	17,544
22,106	15,445	18,631
23,215	16,064	19,731
24,373	16,553	20,845
25,589	16,896	21,977
26,875	16,959	23,100
28,244	16,865	24,265
29,667	18,036	25,876
31,098	19,894	27,721
32,524	21,571	29,526

Table B3 - P&F R#3 – 10,000 ft Water Depth

Pore & Fracture Pressures:		
Depth, SubSea, ft	Pore P, psi	Fracture P, psi
10,000	4,498	4,498
10,260	4,617	4,636
10,804	4,864	4,964
11,393	5,133	5,436
12,025	5,425	5,947
12,686	5,942	6,549
13,364	6,534	7,190
14,055	7,138	7,847
14,760	7,780	8,531
15,478	8,440	9,234
16,213	9,045	9,937
16,974	9,507	10,622
17,763	10,097	11,371
18,573	10,783	12,170
19,402	11,501	13,000
20,253	12,267	13,867
21,131	12,998	14,750
22,045	13,651	15,646
22,996	14,452	16,623
23,983	15,131	17,601
25,000	16,108	18,701
26,037	16,968	19,793
27,106	17,694	20,880
28,215	18,313	21,980
29,373	18,802	23,094
30,589	19,145	24,226
31,875	19,208	25,349
33,244	19,114	26,514
34,667	20,285	28,125
36,098	22,143	29,970
37,524	23,820	31,775

APPENDIX C

SIMULATOR INPUT DATA – SET #1

Run Number: 1

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	2000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

52	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C1 – Input Data Run #1

Run Number: 2

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	2000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea l

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

52	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C2 – Input Data Run #2

Run Number: 3

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	2000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C3 – Input Data Run #3

Run Number: 4

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	2000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C4 – Input Data Run #4

Run Number: 5

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	4000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea Fl

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C5 – Input Data Run #5

Run Number: 6

Kick Type: Gas
Casing Seat: 1500 ft
Water Depth: 3000 ft
Well Depth: 4000 ft
Kick Size: 0.5 ppg
Pit Gain Warning: 50 bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000 Measured length of return line from subsea pump to surface, ft
3000 Vertical depth of return line, ft

Water Data & Others: Sea F

3000 Water Depth, ft
4500 Depth of last Casing from sea level, ft

Kick Data:

104 Amount of Formation Over Pressure, psi
50 Pit Gain Warning Level, bbls

Fig. C6 – Input Data Run #6

Run Number: 7

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	4000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea F

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

208	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C7 – Input Data Run #7

-

Run Number: 8

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	4000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea F

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

208	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C8 – Input Data Run #8

Run Number: **9**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	6000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000 Measured length of return line from subsea pump to surface, ft

3000 Vertical depth of return line, ft

Water Data & Others: Sea F

3000 Water Depth, ft

4500 Depth of last Casing from sea level, ft

Kick Data:

156 Amount of Formation Over Pressure, psi

10 Pit Gain Warning Level, bbls

Fig. C9 – Input Data Run #9

Run Number: 10

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	6000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea Fl

3000	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

156	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C10 – Input Data Run #10

Run Number: 11

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	6000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000	Measured length of return line from subsea pump to surface, ft
3000	Vertical depth of return line, ft

Water Data & Others: Sea F

312	Water Depth, ft
4500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C11 – Input Data Run #11

Run Number: 12

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	3000	ft
Well Depth:	6000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	4500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

3000 Measured length of return line from subsea pump to surface, ft

3000 Vertical depth of return line, ft

Water Data & Others: Sea l

3000 Water Depth, ft

4500 Depth of last Casing from sea level, ft

Kick Data:

312 Amount of Formation Over Pressure, psi

50 Pit Gain Warning Level, bbls

Fig. C12 – Input Data Run #12

Run Number: **13**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	2000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea l

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

52	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C13 – Input Data Run #13

Run Number: 14

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	2000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

52	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C14 – Input Data Run #14

Run Number: 15

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	2000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C15 – Input Data Run #15

Run Number:	**16**	
Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	2000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne:

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C16 – Input Data Run #16

Run Number: 17

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	4000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea l

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C17 – Input Data Run #17

Run Number: **18**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	4000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

1600

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C18 – Input Data Run #18

Run Number: 19

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	4000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

1600

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

208	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C19 – Input Data Run #19

Run Number: 20

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	4000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

1600

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

208	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C20 – Input Data Run #20

Run Number: 21

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	6000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

156	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C21 – Input Data Run #21

Run Number: **22**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	6000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne:

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

156	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C22 – Input Data Run #22

Run Number: **23**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	6000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

312	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C23 – Input Data Run #23

Run Number: 24

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	5000	ft
Well Depth:	6000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	6500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

5000	Measured length of return line from subsea pump to surface, ft
5000	Vertical depth of return line, ft

Water Data & Others: Sea F

5000	Water Depth, ft
6500	Depth of last Casing from sea level, ft

Kick Data:

312	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C24 – Input Data Run #24

Run Number: 25

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	2000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea l

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

52	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C25 – Input Data Run #25

Run Number: 26

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	2000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness of 0

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others:

		Sea Floor (I
		Press
10000	Water Depth, ft	0
11500	Depth of last Casing from sea level, ft	350(

Kick Data:

52	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C26 – Input Data Run #26

Run Number:	**27**	
Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	2000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea F

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C27 – Input Data Run #27

Run Number: 28

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	2000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	8.8	ppg
Plastic Viscosity	5	cp
Yield Point Stress	17	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11100	29	5	1100
3	400	29	5.5	400
3	200	12.25	5.5	200
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea F

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C28 – Input Data Run #28

Run Number: 29

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	4000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea F

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C29 – Input Data Run #29

Run Number: **30**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	4000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea l

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

104	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C30 – Input Data Run #30

Run Number: 31

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	4000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea F

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

208	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C31 – Input Data Run #31

Run Number: 32

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	4000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	12.5	ppg
Plastic Viscosity	16.5	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thicknes

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	1600	12.25	5	1600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea F

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

208	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C32 – Input Data Run #32

Run Number: **33**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	6000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickne:

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea F

10000	Water Depth, ft
11500	Depth of last Casing from sea level, ft

Kick Data:

156	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C33 – Input Data Run #33

Run Number: 34

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	6000	ft
Kick Size:	0.5	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea Flc

10000	Water Depth, ft	P
11500	Depth of last Casing from sea level, ft	

Kick Data:

156	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C34 – Input Data Run #34

Run Number: 35

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	6000	ft
Kick Size:	1	ppg
Pit Gain Warning:	10	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness of 0.5"

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others:

		Sea Floor (Mud Pressure
10000	Water Depth, ft	0
11500	Depth of last Casing from sea level, ft	35000

Kick Data:

312	Amount of Formation Over Pressure, psi
10	Pit Gain Warning Level, bbls

Fig. C35 – Input Data Run #35

Run Number: **36**

Kick Type:	Gas	
Casing Seat:	1500	ft
Water Depth:	10000	ft
Well Depth:	6000	ft
Kick Size:	1	ppg
Pit Gain Warning:	50	bbl

Fluid Data:

Mud Weight	14	ppg
Plastic Viscosity	21	cp
Yield Point Stress	9	lbf/100 sq. ft

Well Geometry Data: Conductor Pipe = 30" OD, 157.53 lb/ft w/ 29" ID & Wall Thickness

Inside Drill String		Annulus Except Return Lin		
ID, inch	Length, ft	OD, inch	ID, inch	Length, ft
4.276	11500	29	5	1500
4.276	3600	12.25	5	3600
3	600	12.25	5.5	600
3.25	300	12.25	8	300

Return Line & Control Lines Data

10000	Measured length of return line from subsea pump to surface, ft
10000	Vertical depth of return line, ft

Water Data & Others: Sea Floo

10000	Water Depth, ft	Pr
11500	Depth of last Casing from sea level, ft	
		3

Kick Data:

312	Amount of Formation Over Pressure, psi
50	Pit Gain Warning Level, bbls

Fig. C36 – Input Data Run #36

APPENDIX D

SIMULATOR INPUT DATA – SET #2

Run Number:	**CS1**						
Kick Type:	Gas						
Casing Seat:	200	ft					
Water Depth:	3000	ft					
Well Depth:	2000	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	8.8	ppg					
Plastic Viscosity	5	cp					
Yield Point Stress	17	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 36" w/ 34" ID & 1" wall thickness - 373.80 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	3200		34	5	200		
4.276	900		12.25	5	900		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
3000	Measured length of return line from subsea pump to surface, ft						
3000	Vertical depth of return line, ft						
Water Data & Others:					Sea Floor (Mud Line)		
3000	Water Depth, ft					Pressure	Depth
3200	Depth of last Casing from sea level, ft					0	3000
						35000	3000
Kick Data:							
104	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D1 – Input Data Runs CS1a and CS1b

Run Number:	**CS2**						
Kick Type:	Gas						
Casing Seat:	2000	ft					
Water Depth:	3000	ft					
Well Depth:	4200	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	12.9	ppg					
Plastic Viscosity	17.5	cp					
Yield Point Stress	9	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 30" w/ 28" ID & 1" wall thickness - 309.72 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	5000		28	5	2000		
4.276	1300		12.25	5	1300		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
3000	Measured length of return line from subsea pump to surface, ft						
3000	Vertical depth of return line, ft						
Water Data & Others:						Sea Floor (Mud Line)	
3000	Water Depth, ft					Pressure	Depth
5000	Depth of last Casing from sea level, ft					0	3000
						35000	3000
Kick Data:							
218.5	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D2 – Input Data Runs CS2a and CS2b

Run Number:	**CS3**						
Kick Type:	Gas						
Casing Seat:	4200	ft					
Water Depth:	3000	ft					
Well Depth:	6000	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	14	ppg					
Plastic Viscosity	24	cp					
Yield Point Stress	9	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 20" w/ 18" ID & 1" wall thickness - 202.92 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	7200		18	5	4200		
4.276	900		12.25	5	900		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
3000	Measured length of return line from subsea pump to surface, ft						
3000	Vertical depth of return line, ft						
Water Data & Others:						Sea Floor (Mud Line)	
3000	Water Depth, ft					Pressure	Depth
7200	Depth of last Casing from sea level, ft					0	3000
						35000	3000
Kick Data:							
312	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D3 – Input Data Runs CS3a and CS3b

Run Number:	**CS4**						
Kick Type:	Gas						
Casing Seat:	200	ft					
Water Depth:	5000	ft					
Well Depth:	2000	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	8.8	ppg					
Plastic Viscosity	5	cp					
Yield Point Stress	17	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 36" w/ 34" ID & 1" wall thickness - 373.80 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	5200		34	5	200		
4.276	900		12.25	5	900		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
5000	Measured length of return line from subsea pump to surface, ft						
5000	Vertical depth of return line, ft						
Water Data & Others:					Sea Floor (Mud Line)		(
5000	Water Depth, ft					Pressure	Depth
5200	Depth of last Casing from sea level, ft					0	5000
						35000	5000
Kick Data:							
104	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D4 – Input Data Runs CS4a and CS4b

Run Number:	**CS5**						
Kick Type:	Gas						
Casing Seat:	2000	ft					
Water Depth:	5000	ft					
Well Depth:	4200	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	12.9	ppg					
Plastic Viscosity	17.5	cp					
Yield Point Stress	9	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 30" w/ 28" ID & 1" wall thickness - 309.72 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	7000		28	5	2000		
4.276	1300		12.25	5	1300		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
5000	Measured length of return line from subsea pump to surface, ft						
5000	Vertical depth of return line, ft						
Water Data & Others:					Sea Floor (Mud Line)		(
5000	Water Depth, ft					Pressure	Depth
7000	Depth of last Casing from sea level, ft					0	5000
						35000	5000
Kick Data:							
218.5	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D5 – Input Data Runs CS5a and CS5b

Run Number:	**CS6**						
Kick Type:	Gas						
Casing Seat:	4200	ft					
Water Depth:	5000	ft					
Well Depth:	6000	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	14	ppg					
Plastic Viscosity	24	cp					
Yield Point Stress	9	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 20" w/ 18" ID & 1" wall thickness - 202.92 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	9200		18	5	4200		
4.276	900		12.25	5	900		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
5000	Measured length of return line from subsea pump to surface, ft						
5000	Vertical depth of return line, ft						
Water Data & Others:					Sea Floor (Mud Line)		
5000	Water Depth, ft					Pressure	Depth
9200	Depth of last Casing from sea level, ft					0	5000
						35000	5000
Kick Data:							
312	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D6 – Input Data Runs CS6a and CS6b

Run Number:	**CS7**						
Kick Type:	Gas						
Casing Seat:	200	ft					
Water Depth:	10000	ft					
Well Depth:	2000	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	8.8	ppg					
Plastic Viscosity	5	cp					
Yield Point Stress	17	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 36" w/ 34" ID & 1" wall thickness - 373.80 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	10200		34	5	200		
4.276	900		12.25	5	900		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
10000	Measured length of return line from subsea pump to surface, ft						
10000	Vertical depth of return line, ft						
Water Data & Others:					Sea Floor (Mud Line)		
10000	Water Depth, ft					Pressure	Depth
10200	Depth of last Casing from sea level, ft					0	10000
						35000	10000
Kick Data:							
104	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D7 – Input Data Runs CS7a and CS7b

Run Number:	**CS8**						
Kick Type:	Gas						
Casing Seat:	2000	ft					
Water Depth:	10000	ft					
Well Depth:	4200	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	12.9	ppg					
Plastic Viscosity	17.5	cp					
Yield Point Stress	9	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 30" w/ 28" ID & 1" wall thickness - 309.72 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	12000		28	5	2000		
4.276	1300		12.25	5	1300		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
10000	Measured length of return line from subsea pump to surface, ft						
10000	Vertical depth of return line, ft						
Water Data & Others:					Sea Floor (Mud Line)		C
10000	Water Depth, ft					Pressure	Depth
12000	Depth of last Casing from sea level, ft					0	10000
						35000	10000
Kick Data:							
218.5	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D8 – Input Data Runs CS8a and CS8b

Run Number:	**CS9**						
Kick Type:	Gas						
Casing Seat:	4200	ft					
Water Depth:	10000	ft					
Well Depth:	6000	ft					
Kick Size:	1	ppg					
Pit Gain Warning:	50	bbl					
Fluid Data:							
Mud Weight	14	ppg					
Plastic Viscosity	24	cp					
Yield Point Stress	9	lbf/100 sq. ft					
Well Geometry Data:	Conductor Pipe = 20" w/ 18" ID & 1" wall thickness - 202.92 lb/ft						
Inside Drill String			Annulus Except Return Lin				
ID, inch	Length, ft		OD, inch	ID, inch	Length, ft		
4.276	14200		18	5	4200		
4.276	900		12.25	5	900		
3	600		12.25	5.5	600		
3.25	300		12.25	8	300		
Return Line & Control Lines Data							
10000	Measured length of return line from subsea pump to surface, ft						
10000	Vertical depth of return line, ft						
Water Data & Others:					Sea Floor (Mud Line)		C
10000	Water Depth, ft					Pressure	Depth
14200	Depth of last Casing from sea level, ft					0	10000
						35000	10000
Kick Data:							
312	Amount of Formation Over Pressure, psi						
50	Pit Gain Warning Level, bbls						

Fig. D9 – Input Data Runs CS9a and CS9b

APPENDIX E

PRESSURE @ TOP OF KICK GRAPHS – SET #1

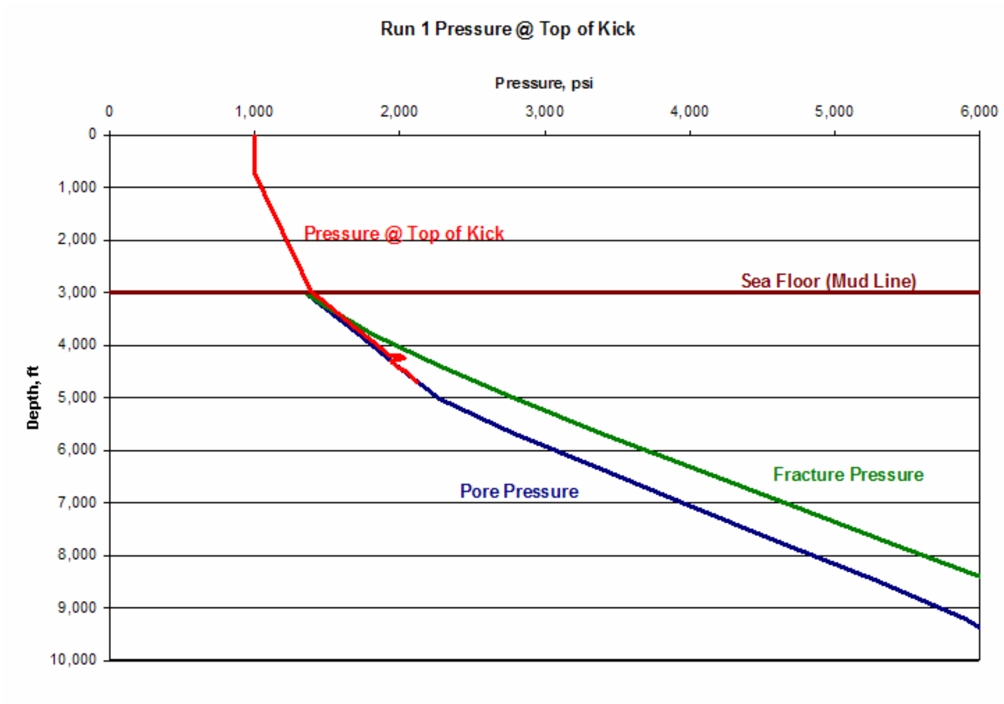

Fig. E1 – Pressure @ Top of Kick in Run 1

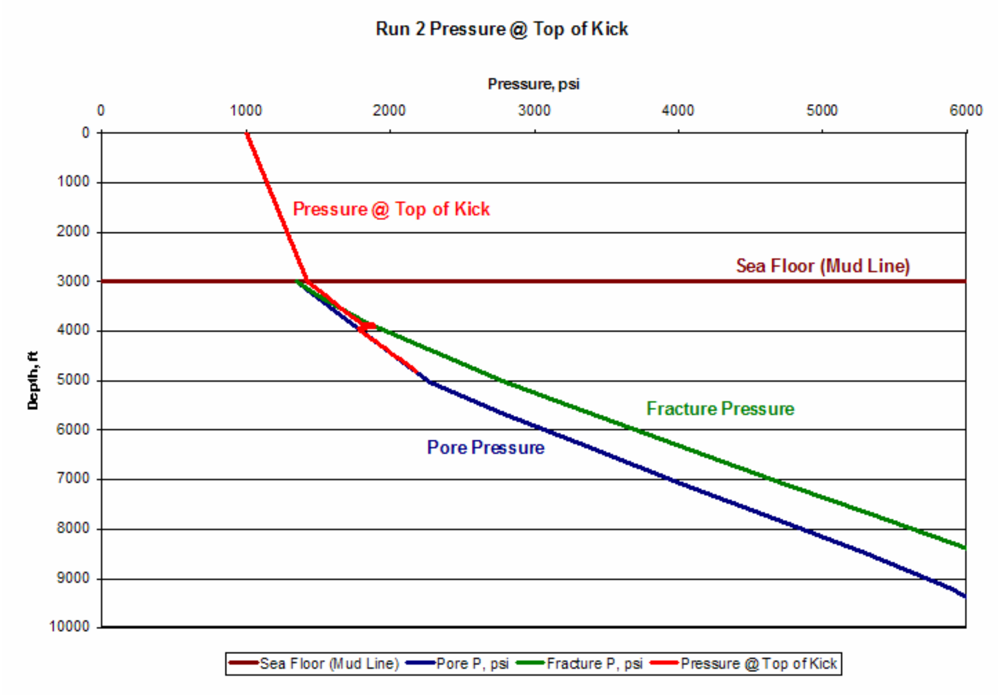

Fig. E2 – Pressure @ Top of Kick in Run 2

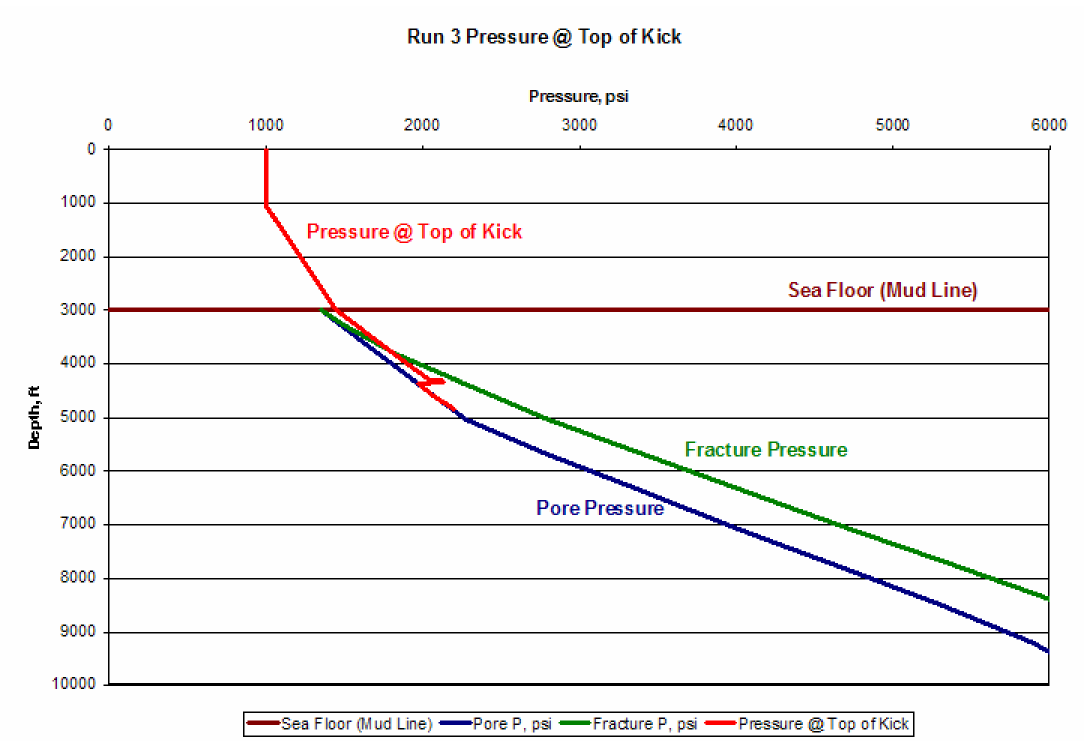

Fig. E3 – Pressure @ Top of Kick in Run 3

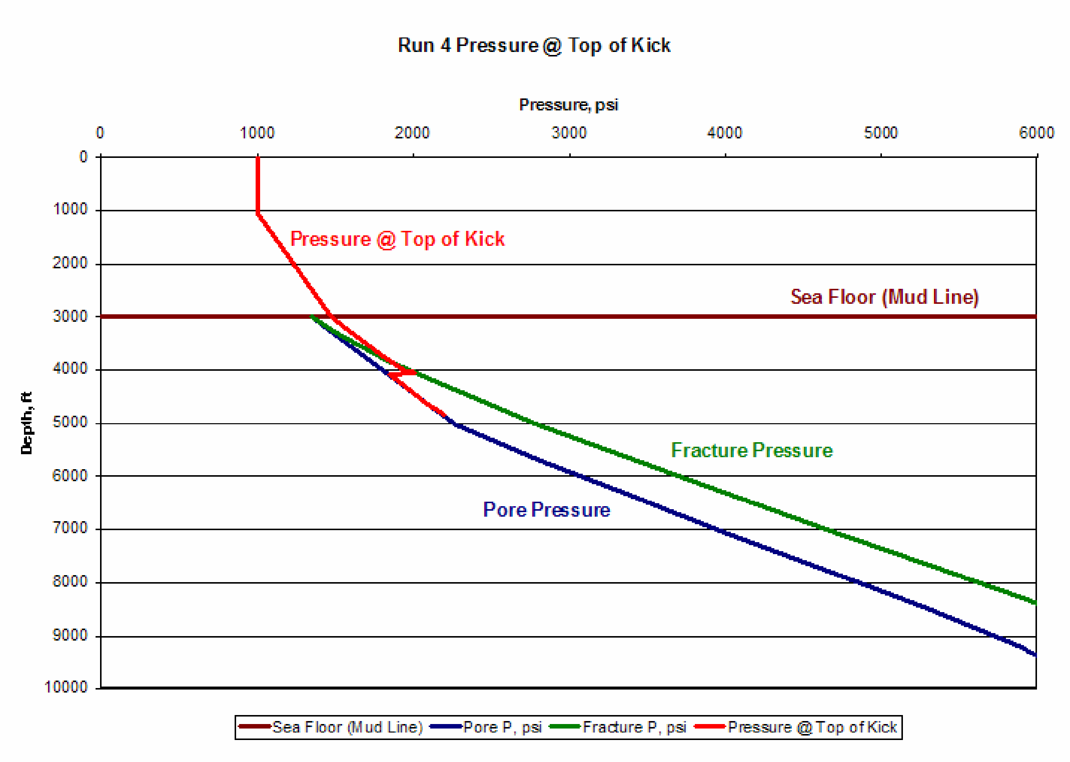

Fig. E4 – Pressure @ Top of Kick in Run 4

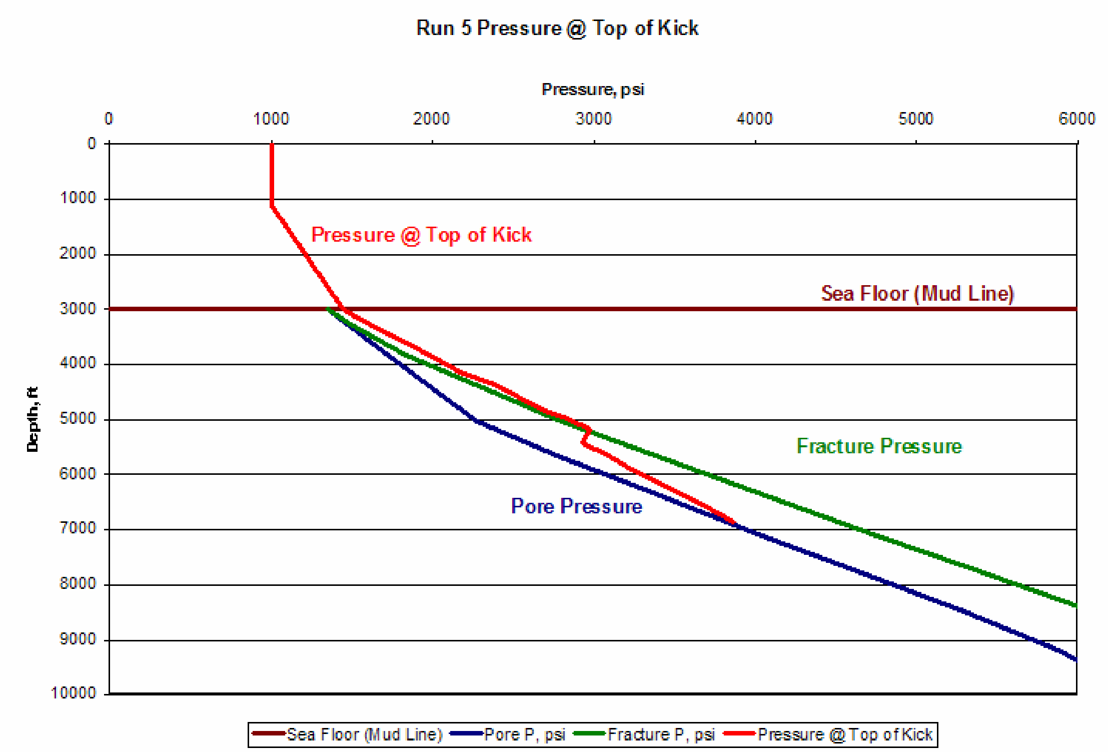

Fig. E5 – Pressure @ Top of Kick in Run 5

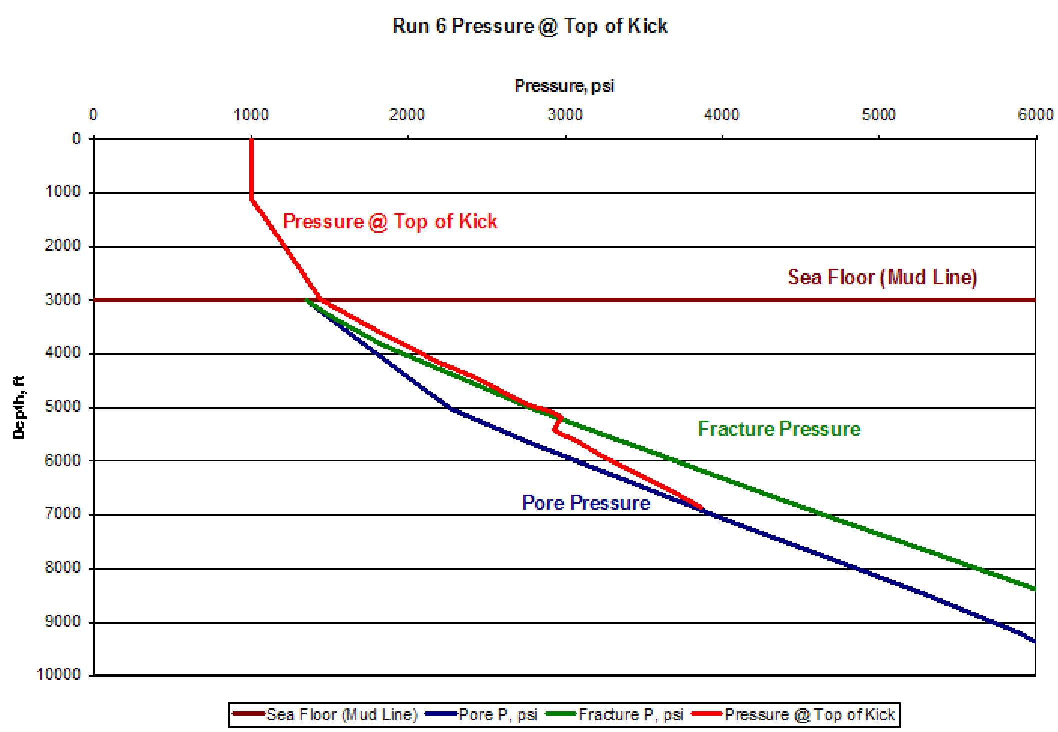

Fig. E6 – Pressure @ Top of Kick in Run 6

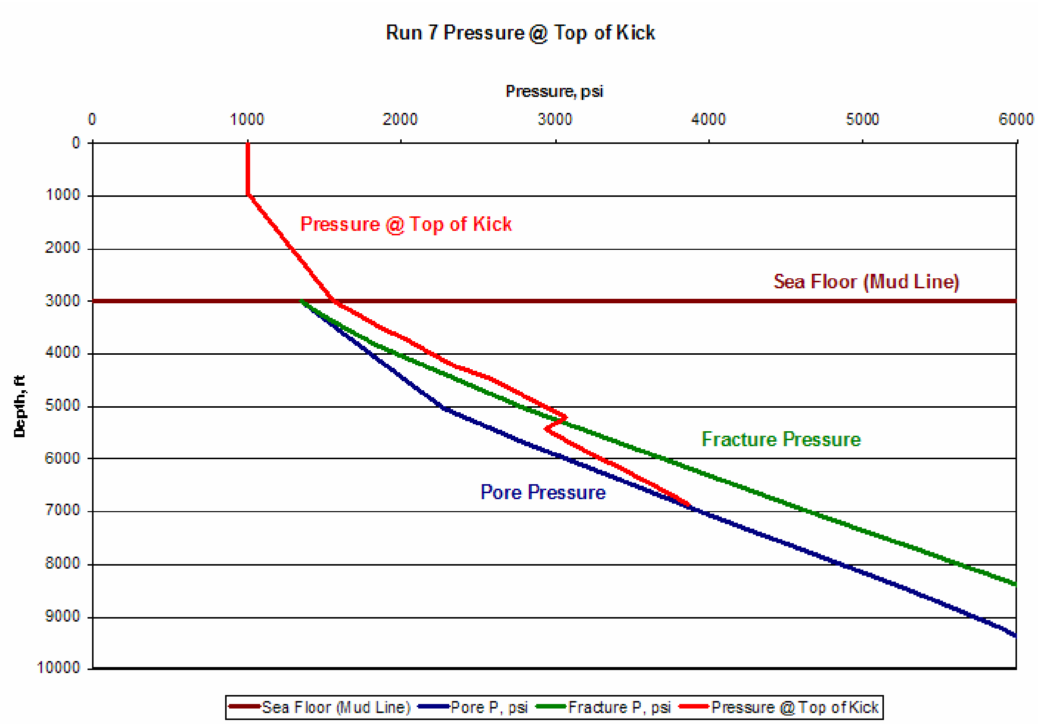

Fig. E7 – Pressure @ Top of Kick in Run 7

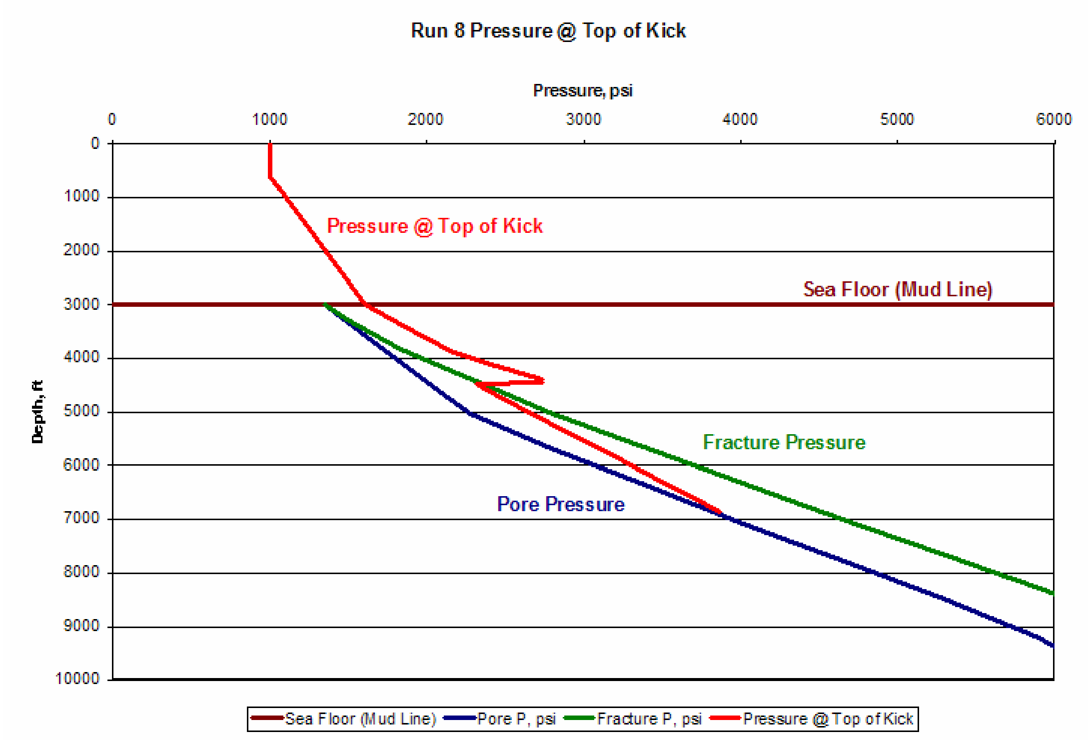

Fig. E8 – Pressure @ Top of Kick in Run 8

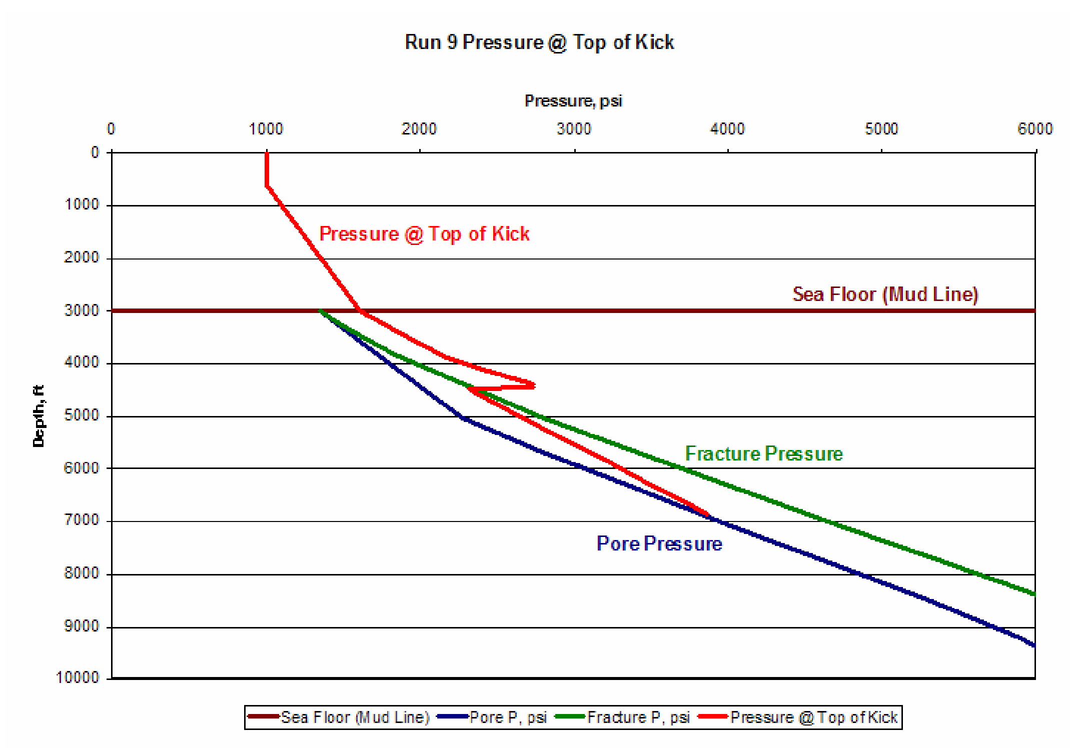

Fig. E9 – Pressure @ Top of Kick in Run 9

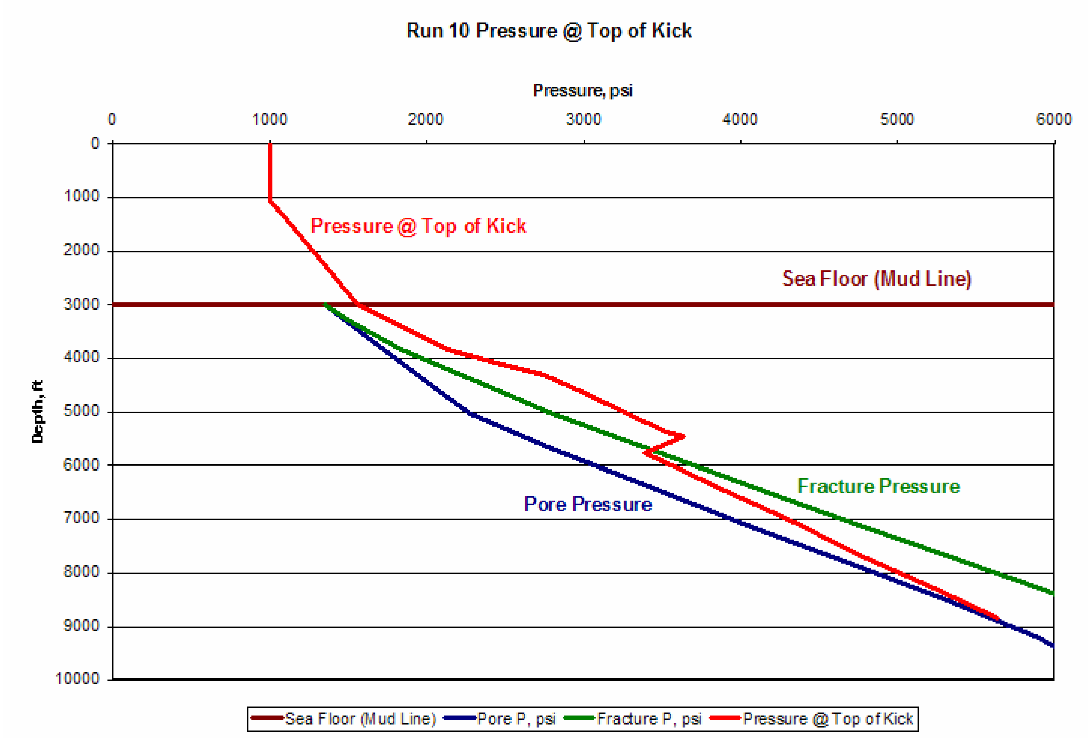

Fig. E10 – Pressure @ Top of Kick in Run 10

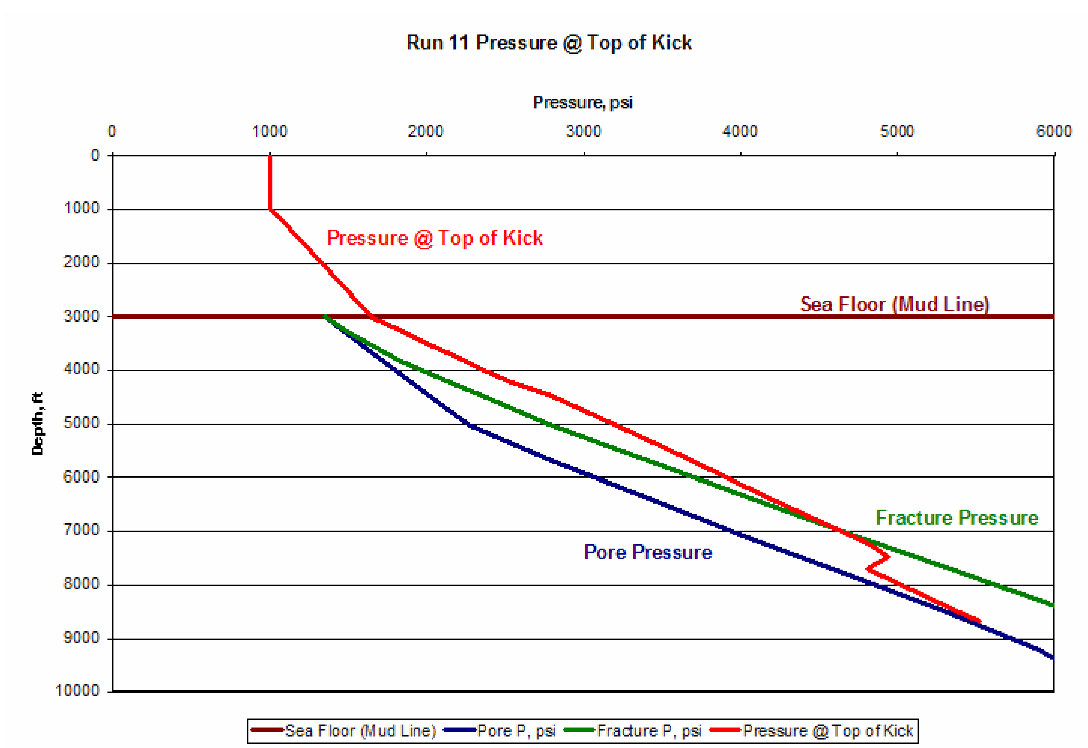

Fig. E11 – Pressure @ Top of Kick in Run 11

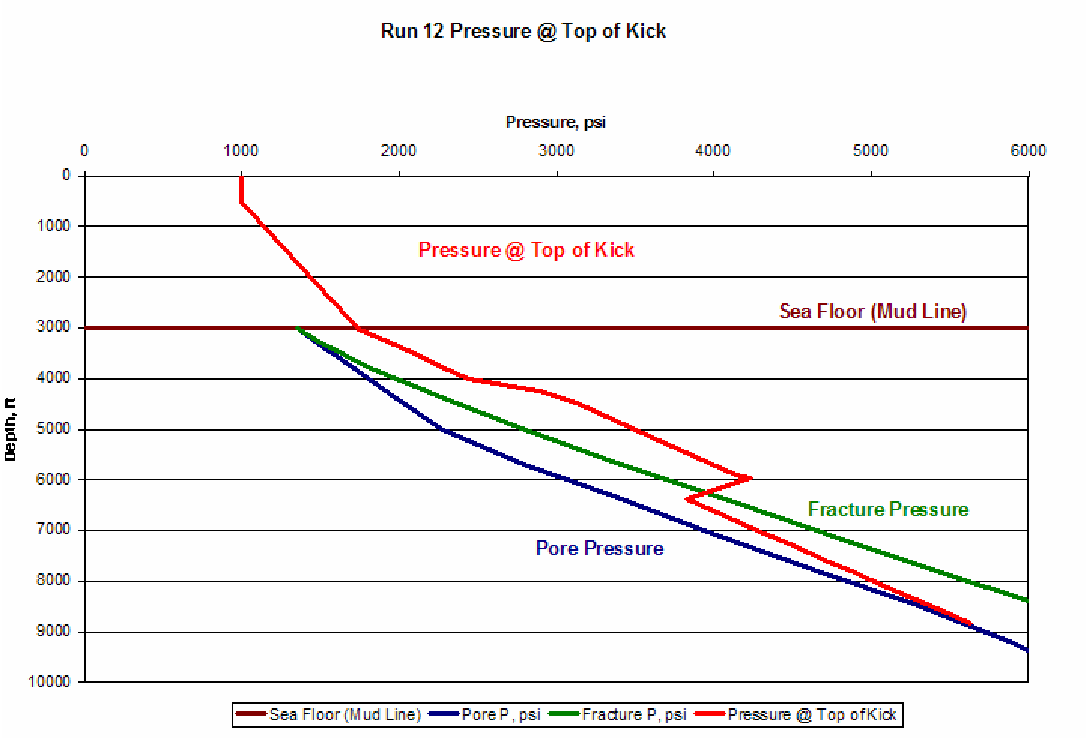

Fig. E12 – Pressure @ Top of Kick in Run 12

Fig. E13 – Pressure @ Top of Kick in Run 13

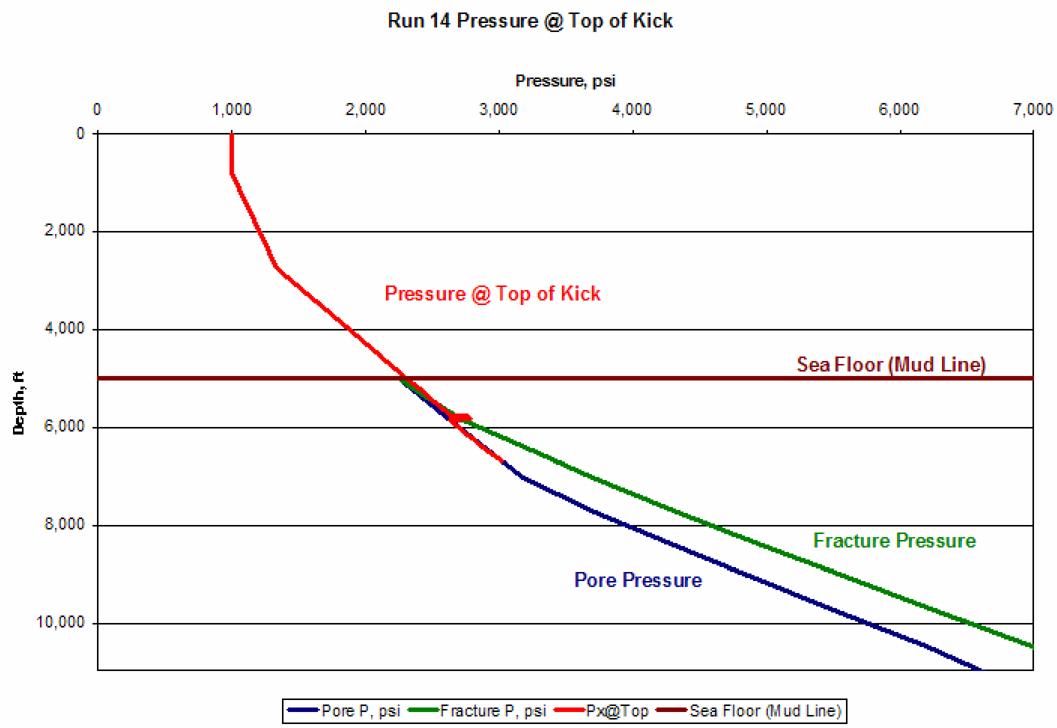

Fig. E14 – Pressure @ Top of Kick in Run 14

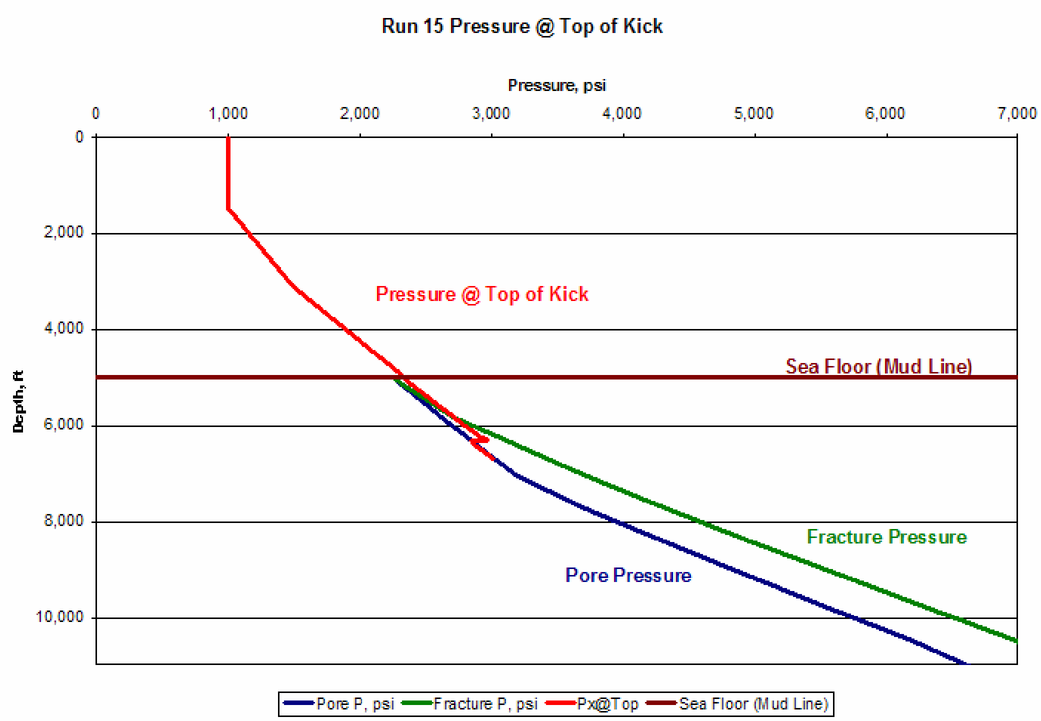

Fig. E15 – Pressure @ Top of Kick in Run 15

Fig. E16 – Pressure @ Top of Kick in Run 16

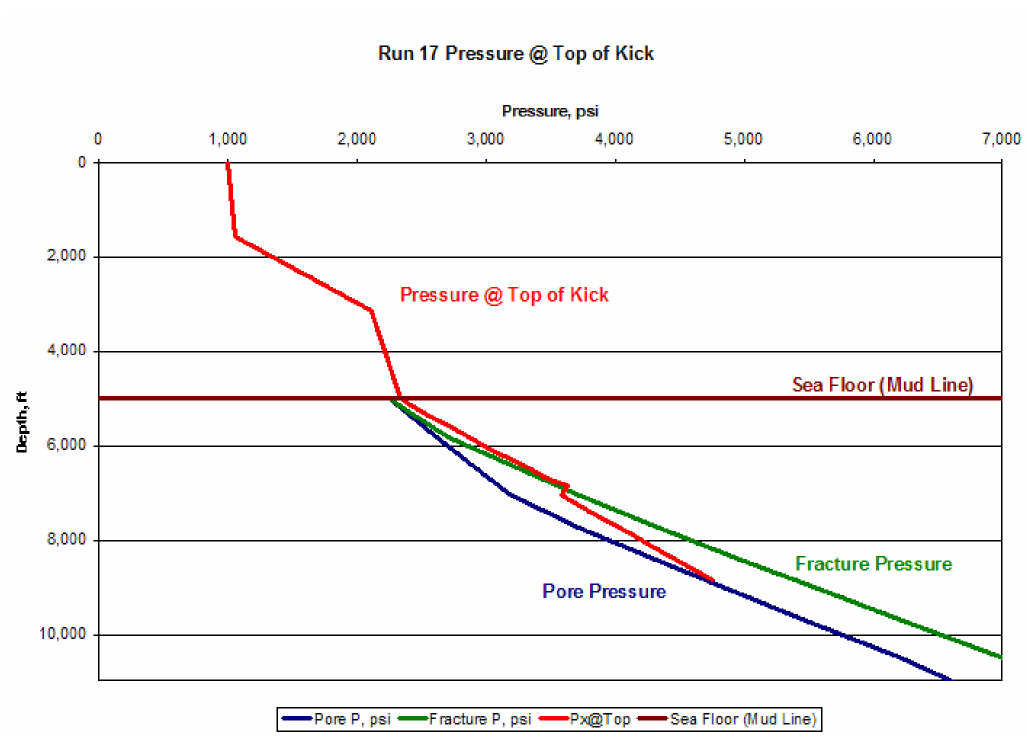

Fig. E17 – Pressure @ Top of Kick in Run 17

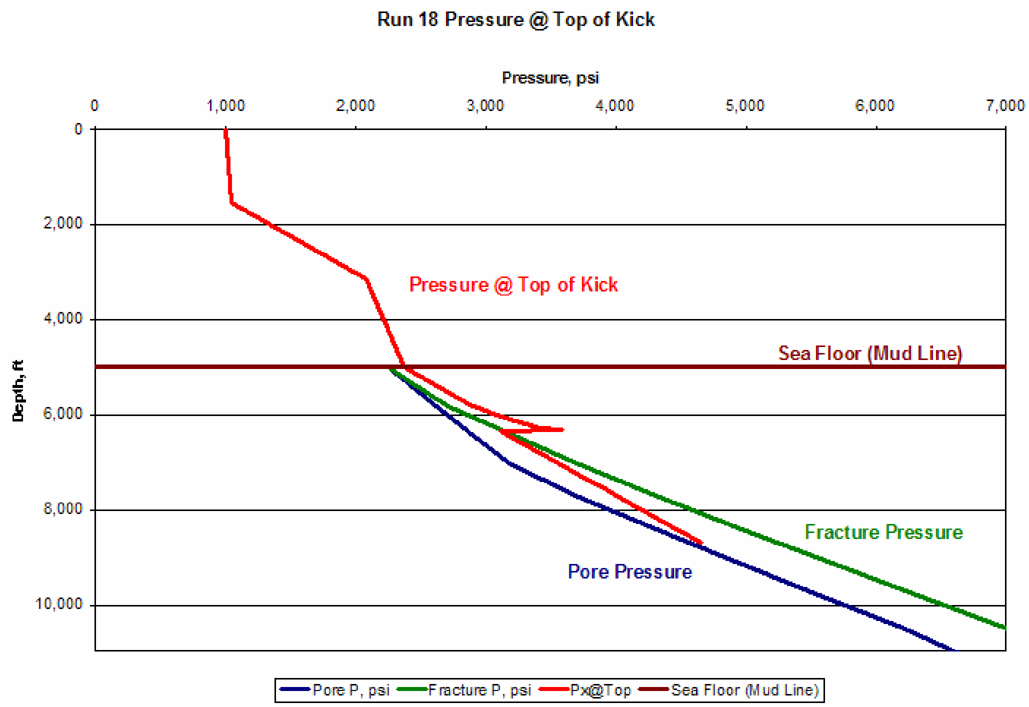

Fig. E18 – Pressure @ Top of Kick in Run 18

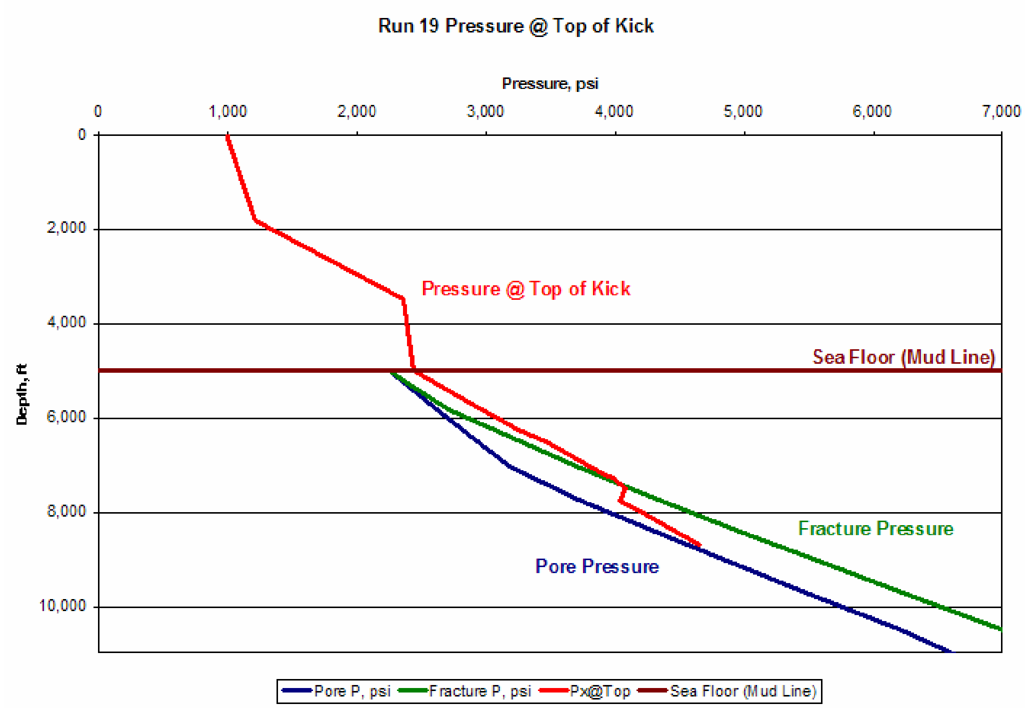

Fig. E19 – Pressure @ Top of Kick in Run 19

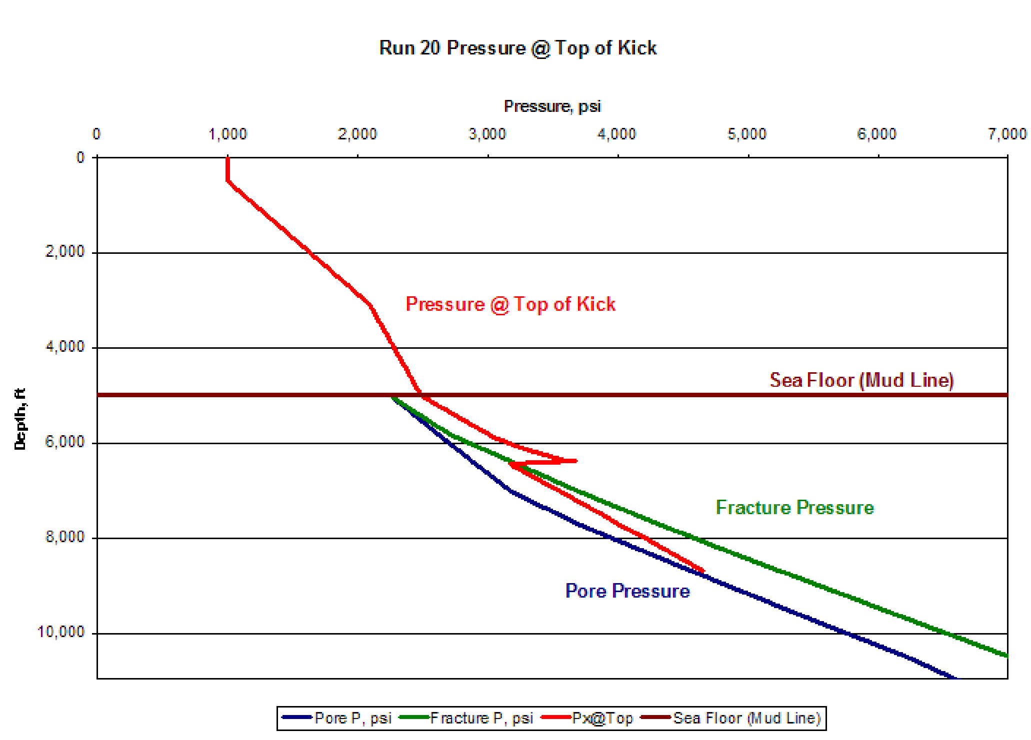

Fig. E20 – Pressure @ Top of Kick in Run 20

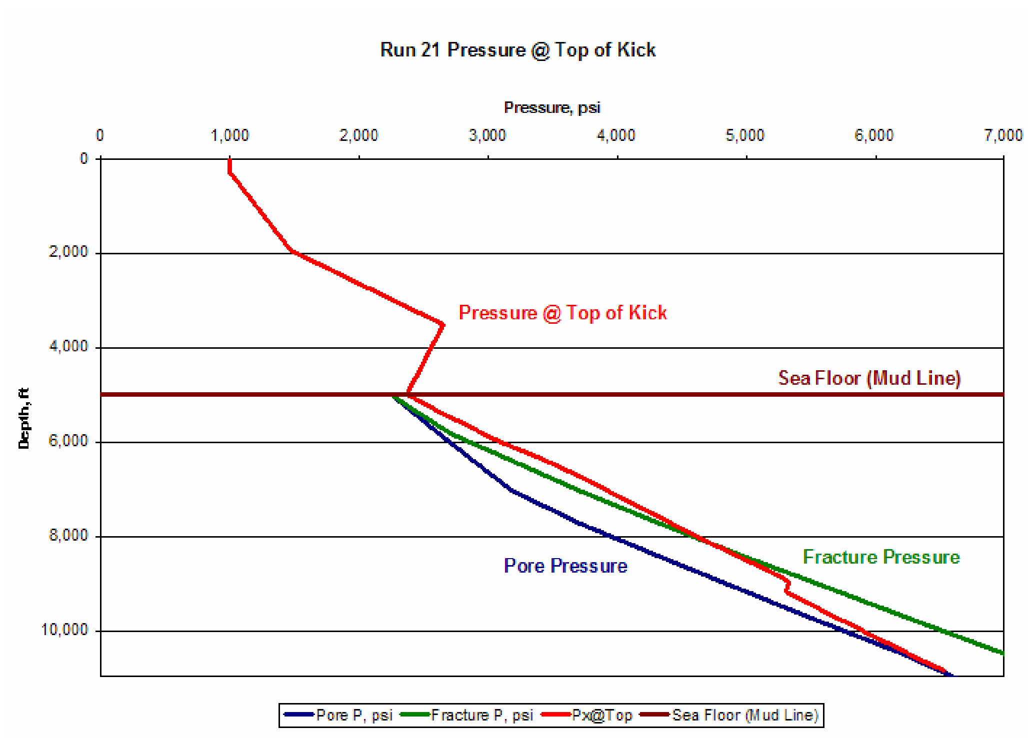

Fig. E21 – Pressure @ Top of Kick in Run 21

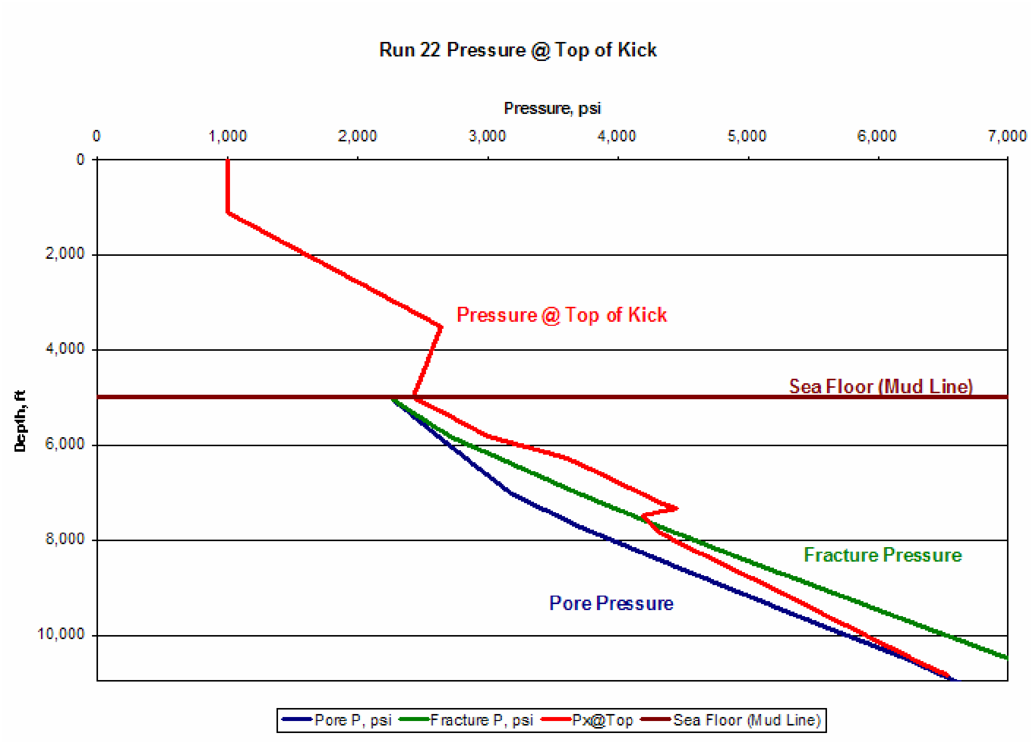

Fig. E22 – Pressure @ Top of Kick in Run 22

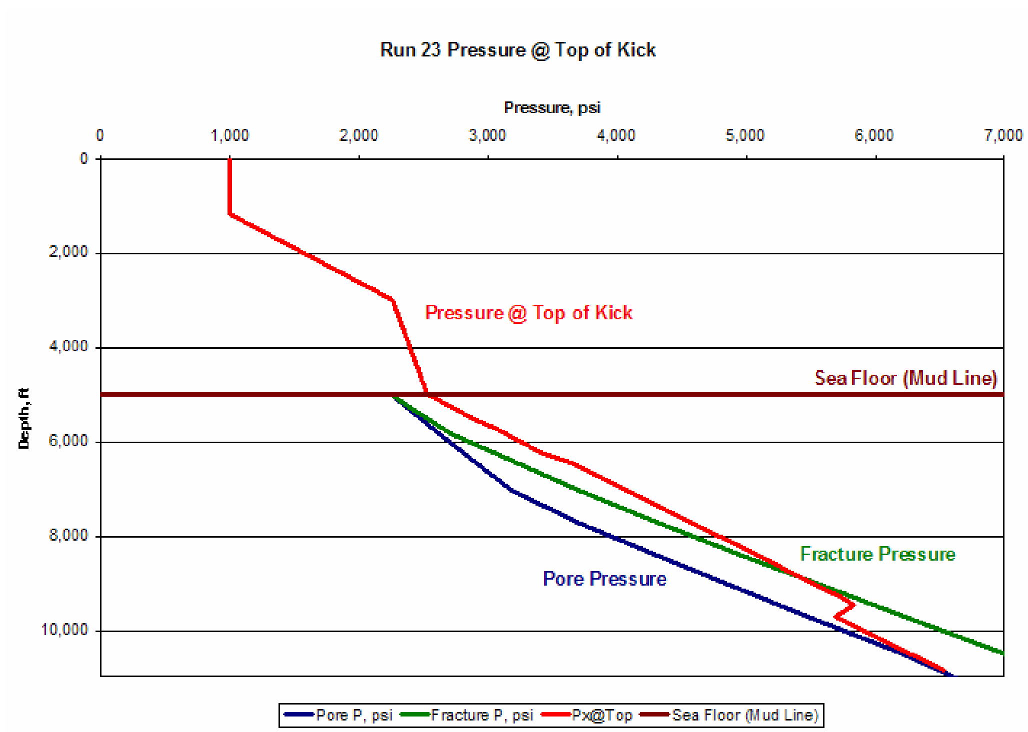

Fig. E23 – Pressure @ Top of Kick in Run 23

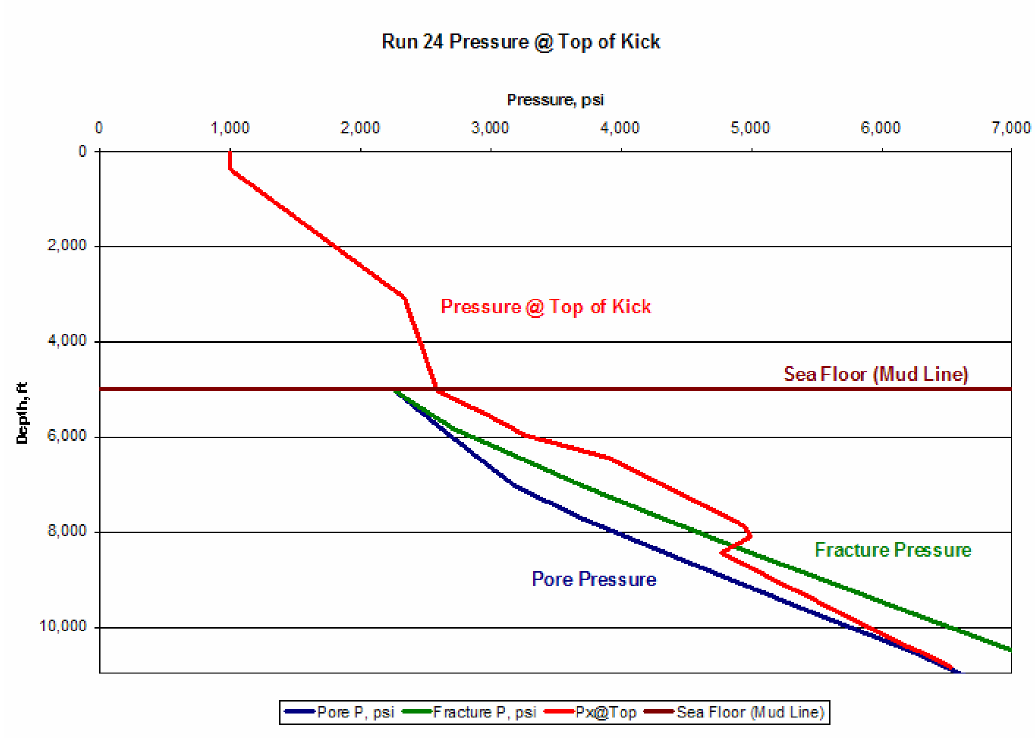

Fig. E24 – Pressure @ Top of Kick in Run 24

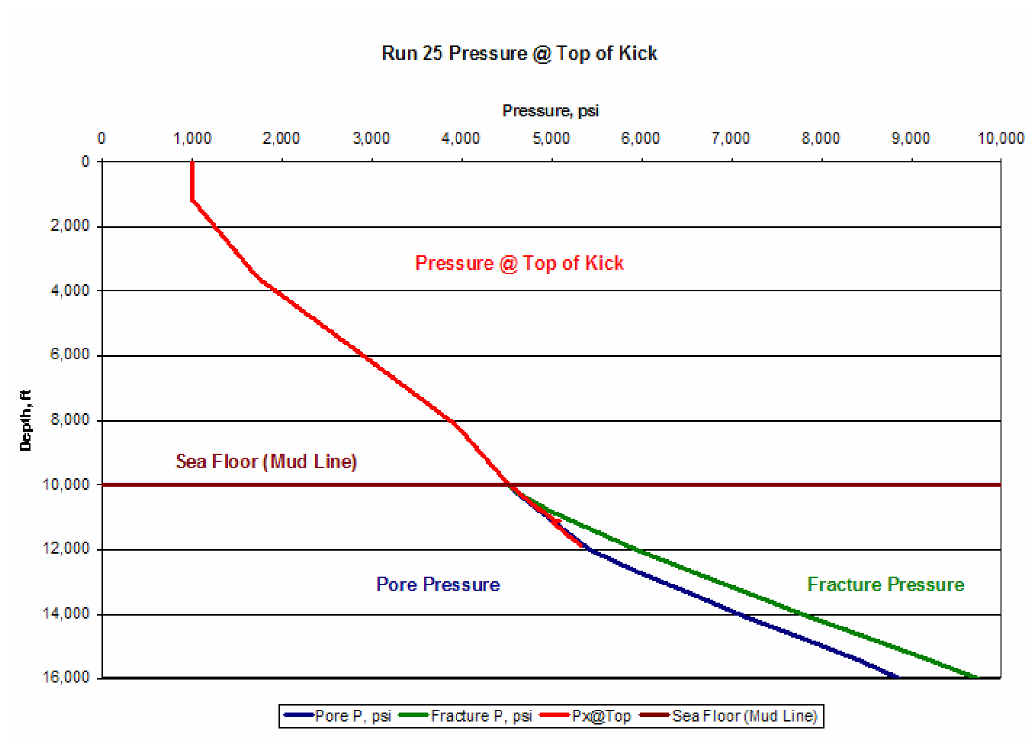

Fig. E25 – Pressure @ Top of Kick in Run 25

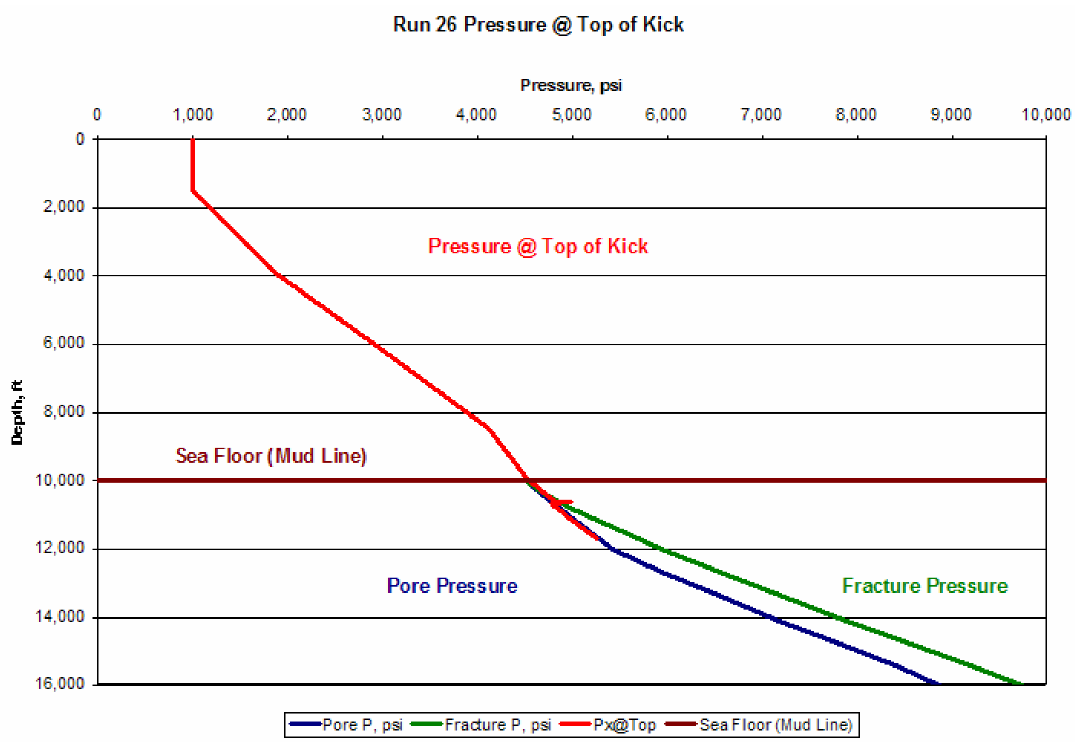

Fig. E26 – Pressure @ Top of Kick in Run 26

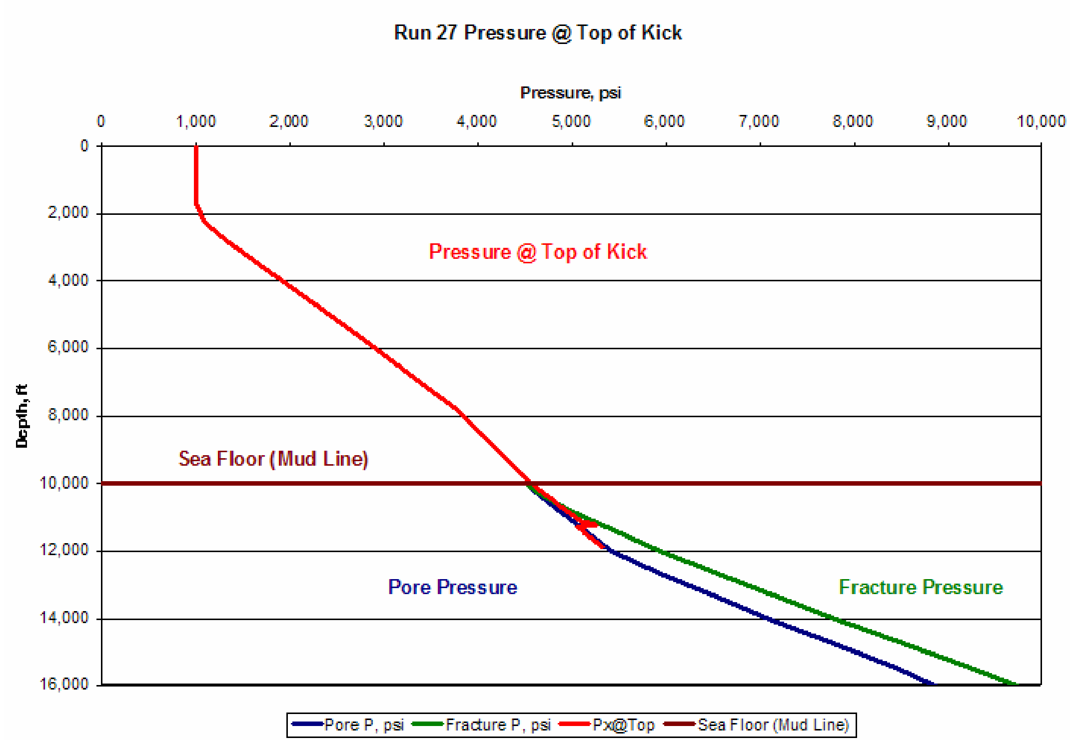

Fig. E27 – Pressure @ Top of Kick in Run 27

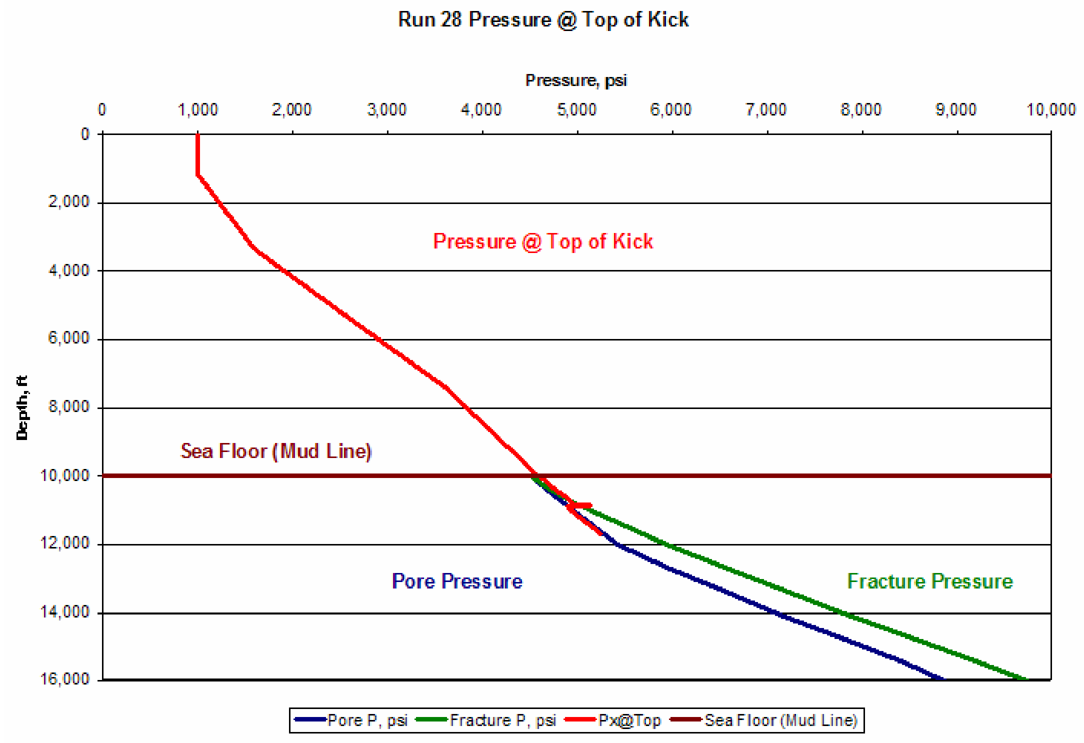

Fig. E28 – Pressure @ Top of Kick in Run 28

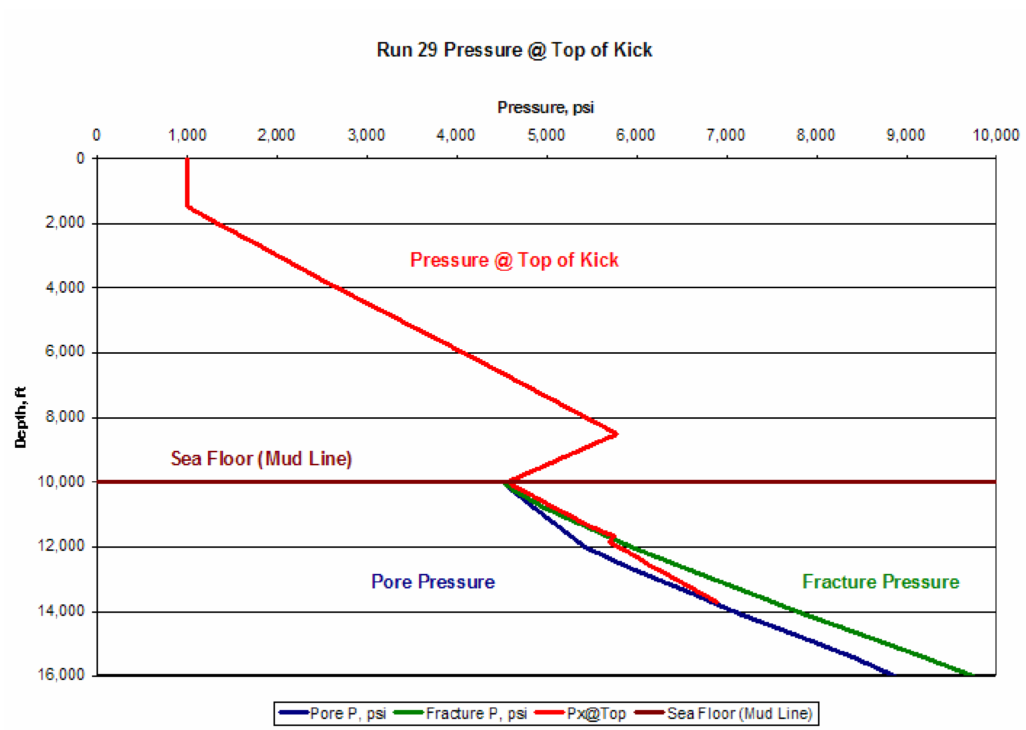

Fig. E29 – Pressure @ Top of Kick in Run 29

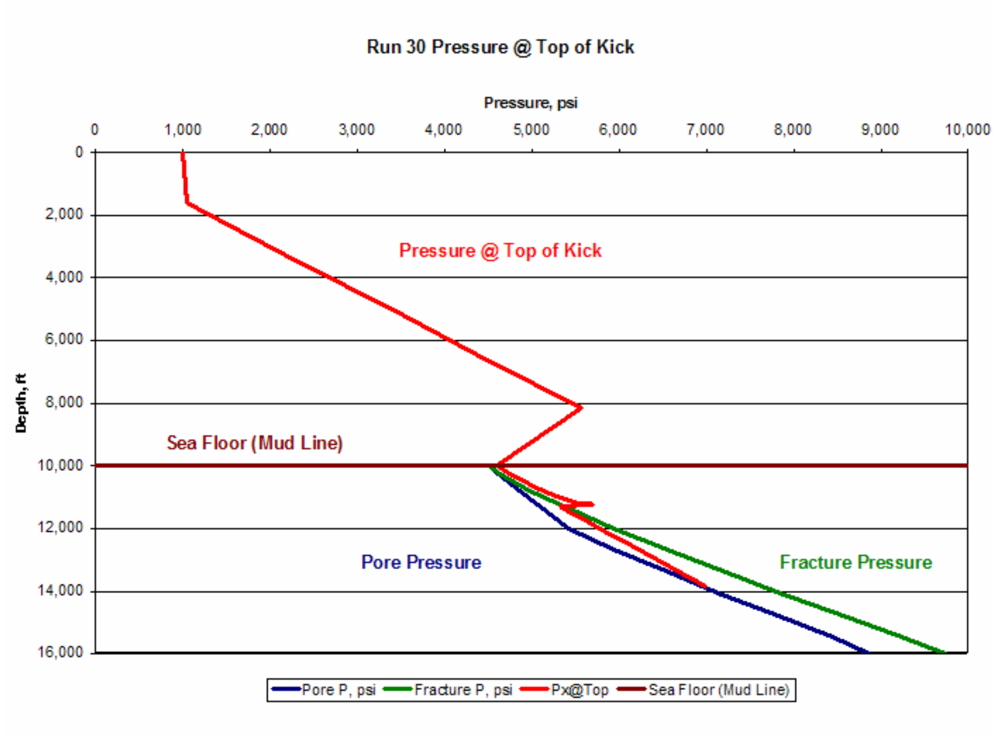

Fig. E30 – Pressure @ Top of Kick in Run 30

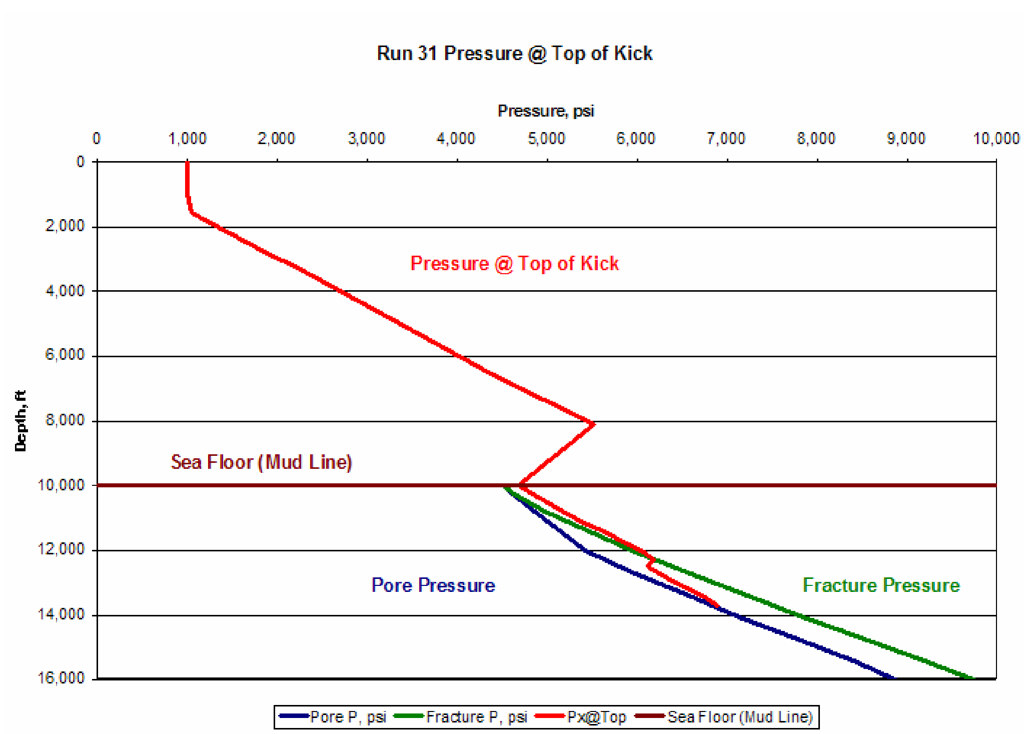

Fig. E31 – Pressure @ Top of Kick in Run 31

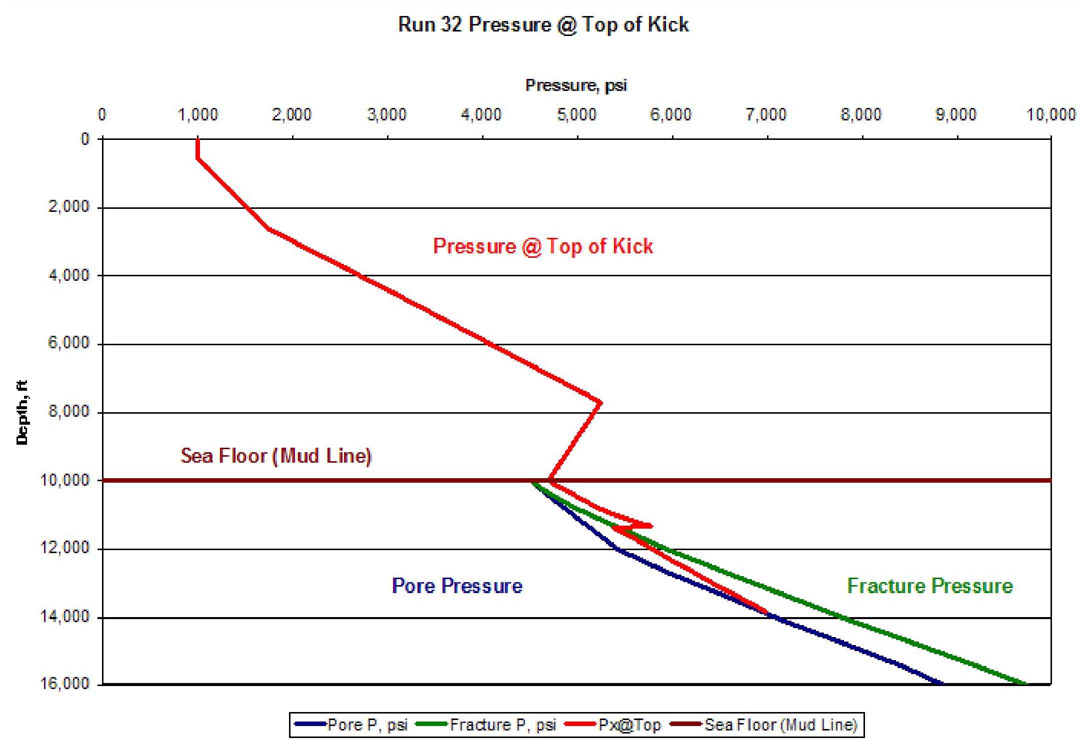

Fig. E32 – Pressure @ Top of Kick in Run 32

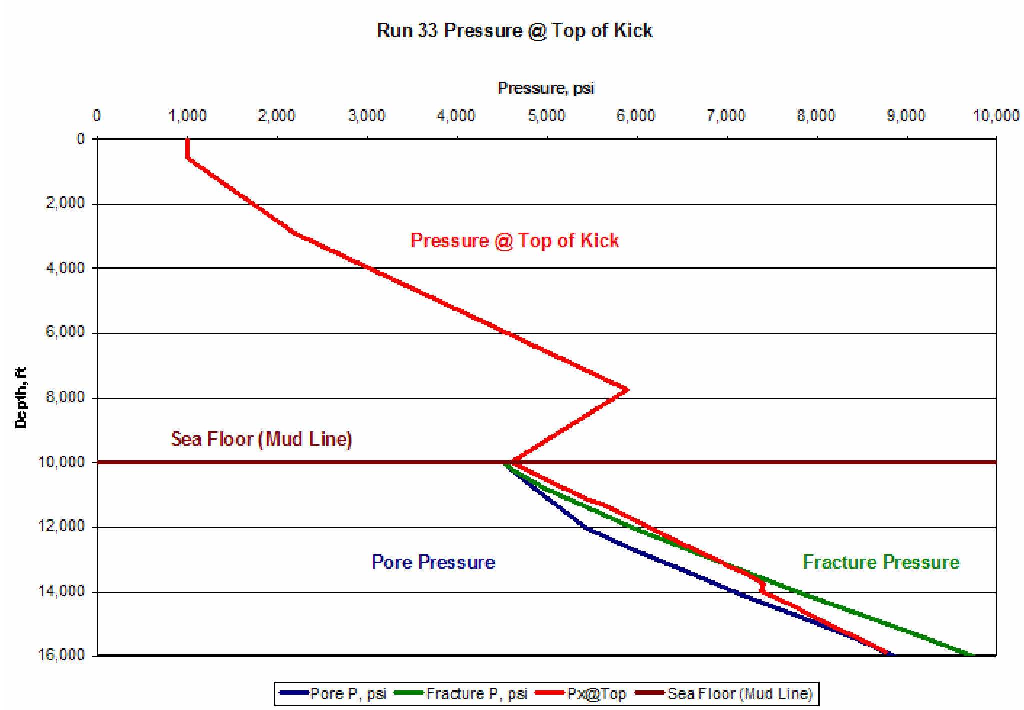

Fig. E33 – Pressure @ Top of Kick in Run 33

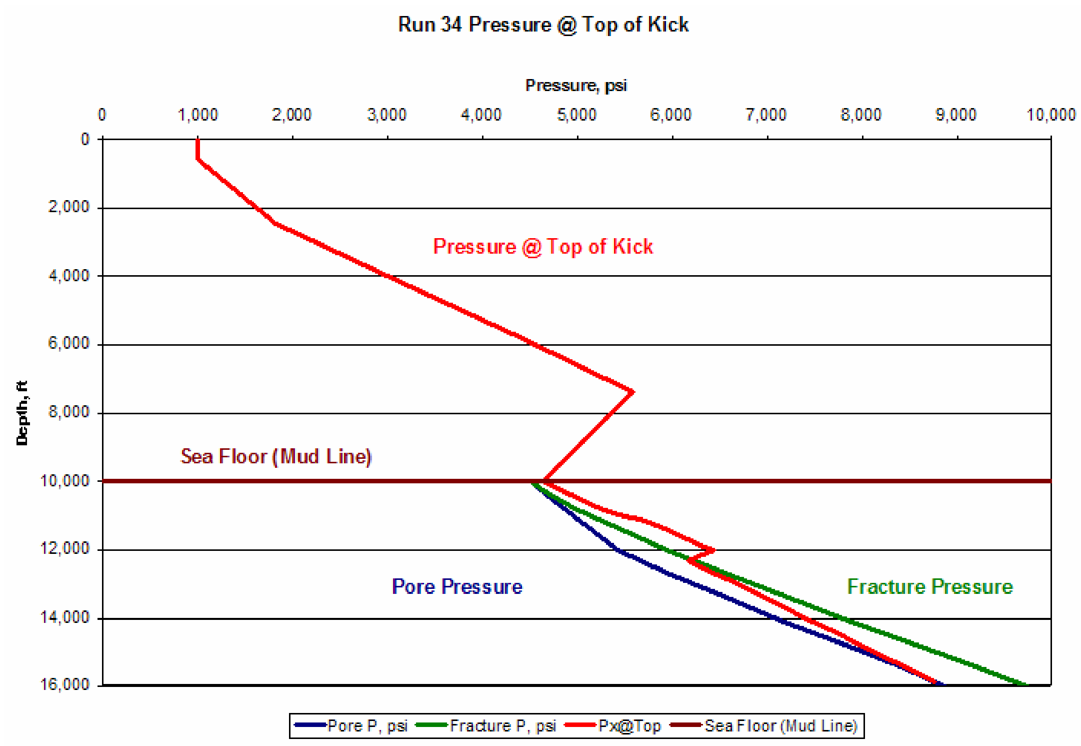

Fig. E34 – Pressure @ Top of Kick in Run 34

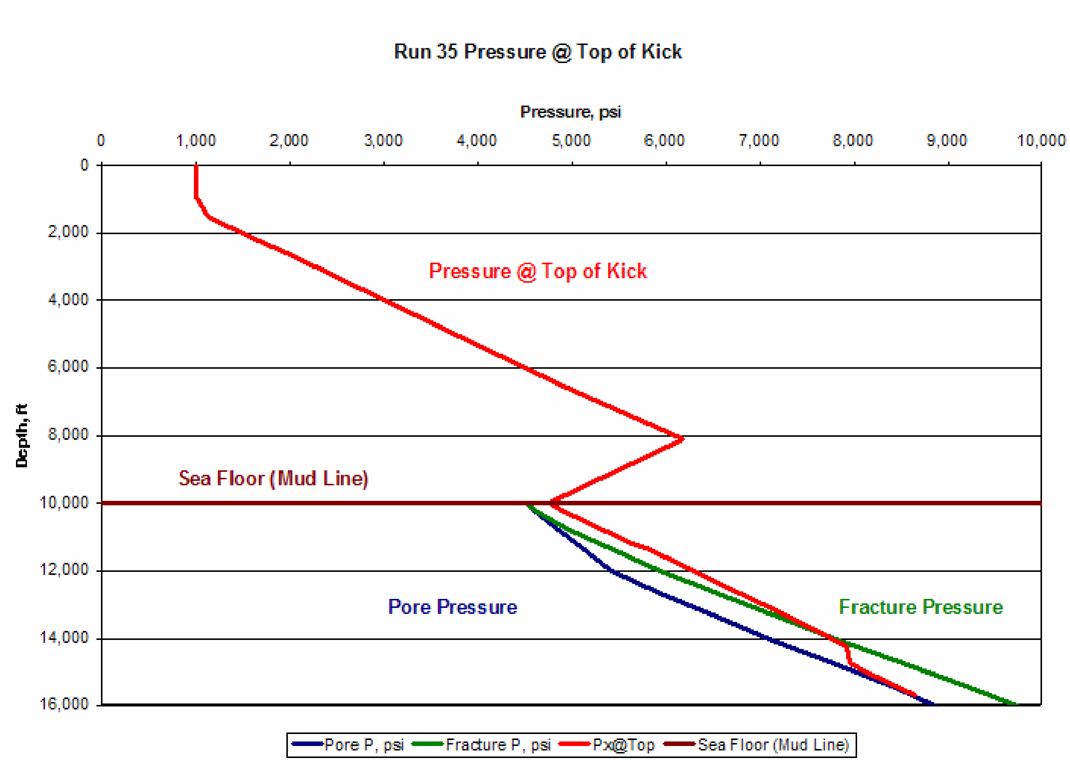

Fig. E35 – Pressure @ Top of Kick in Run 35

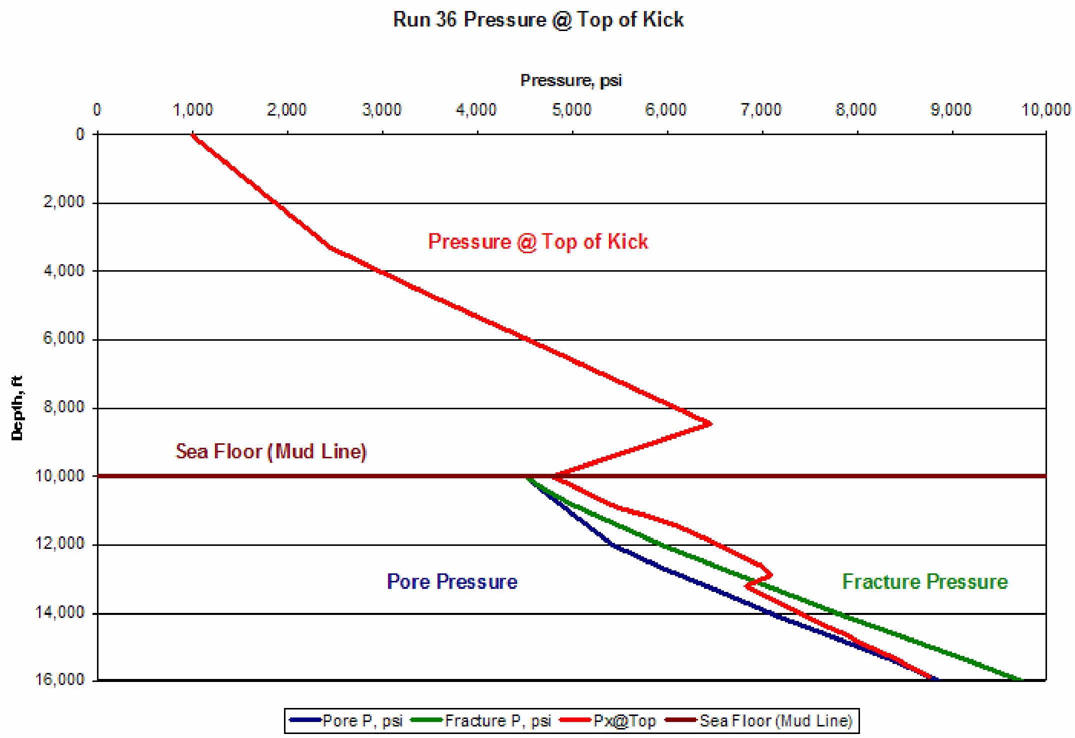

Fig. E36 – Pressure @ Top of Kick in Run 36

APPENDIX F

PRESSURE @ TOP OF KICK GRAPHS – SET #2

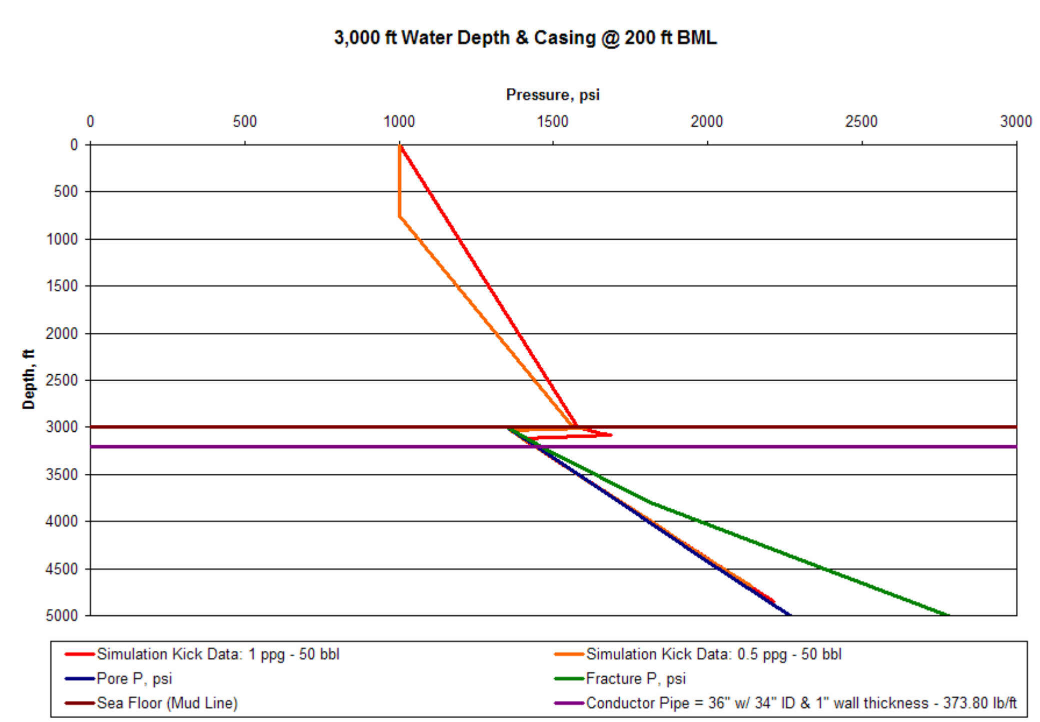

Fig. F1 – Pressure @ Top of Kick in Runs CS1a and CS1b

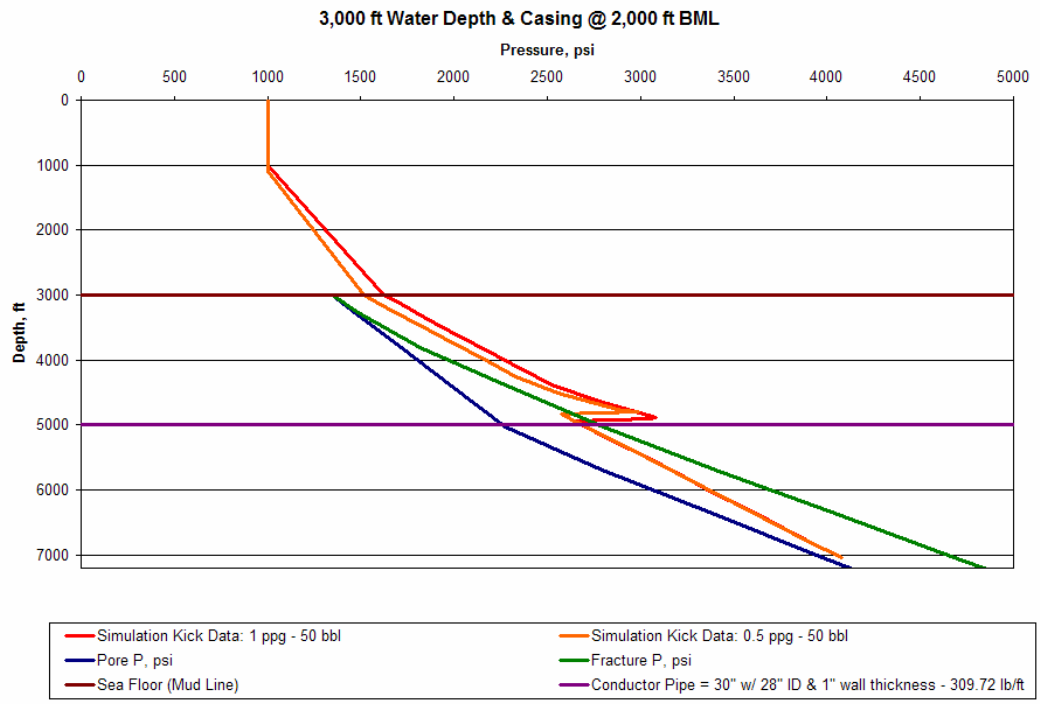

Fig. F2 – Pressure @ Top of Kick in Runs CS2a and CS2b

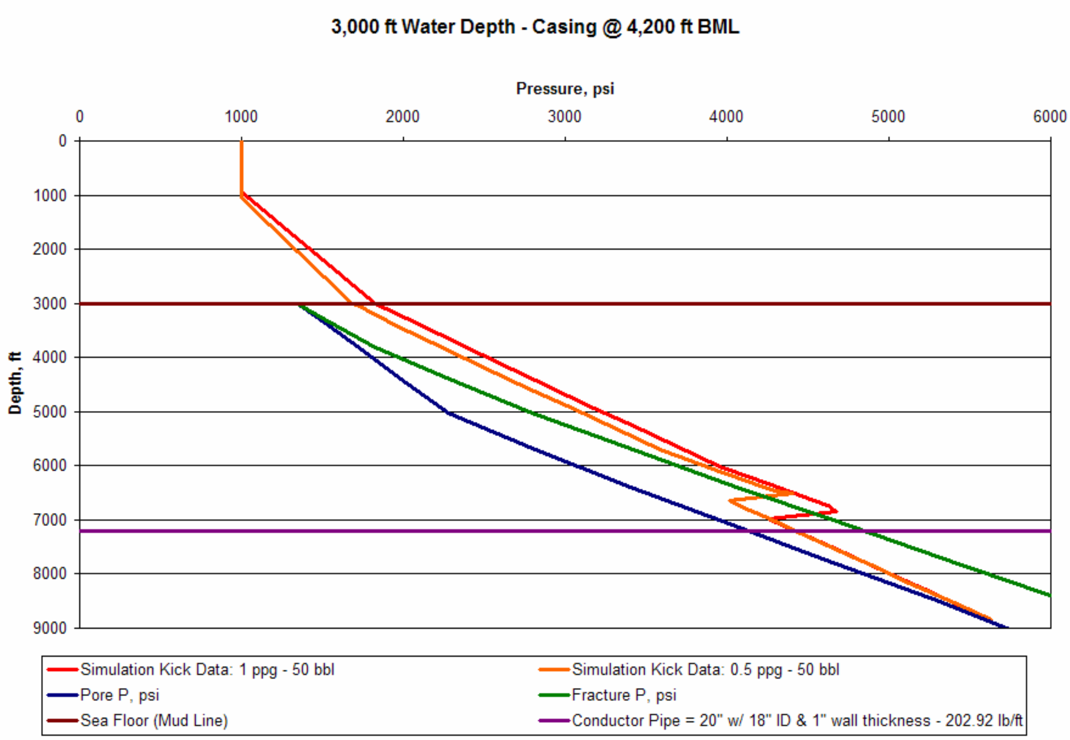

Fig. F3 – Pressure @ Top of Kick in Runs CS3a and CS3b

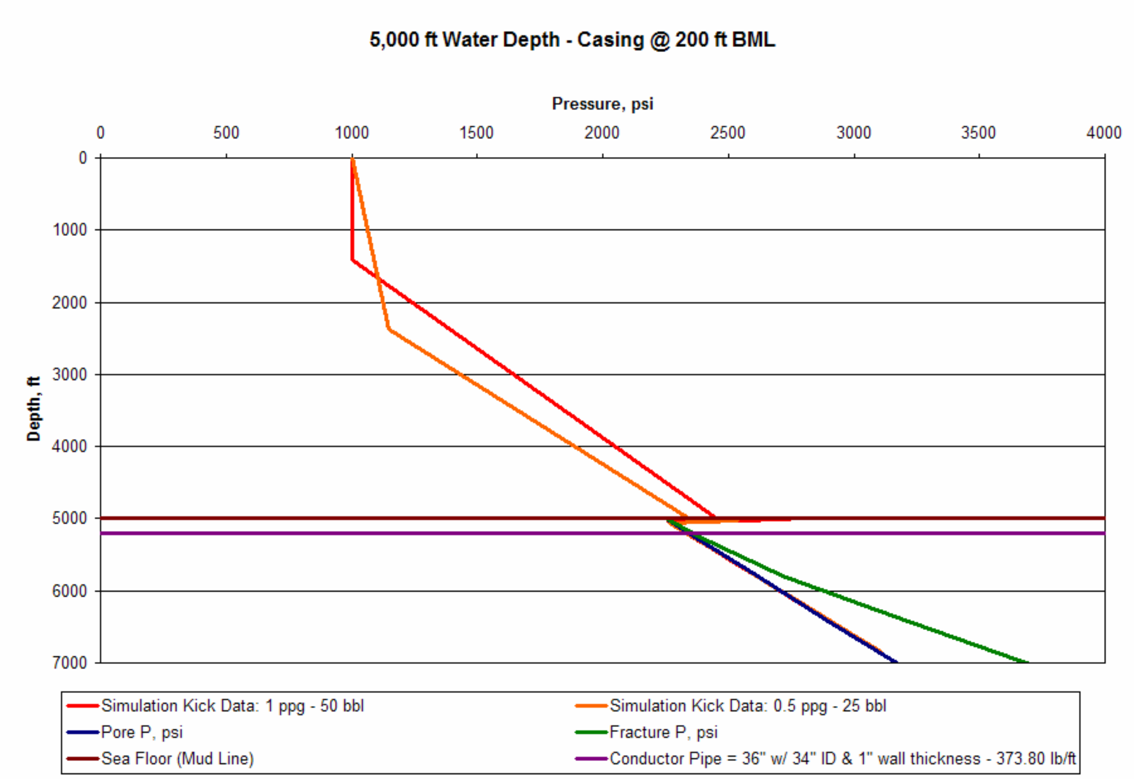

Fig. F4 – Pressure @ Top of Kick in Runs CS4a and CS4b

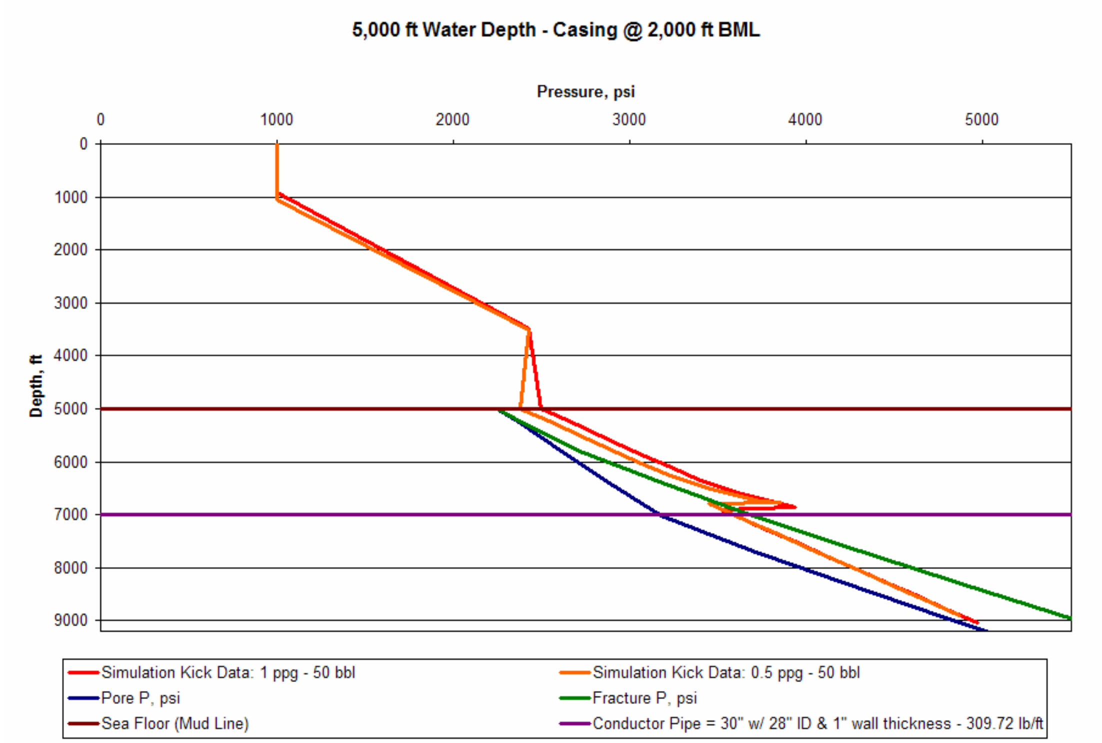

Fig. F5 – Pressure @ Top of Kick in Runs CS5a and CS5b

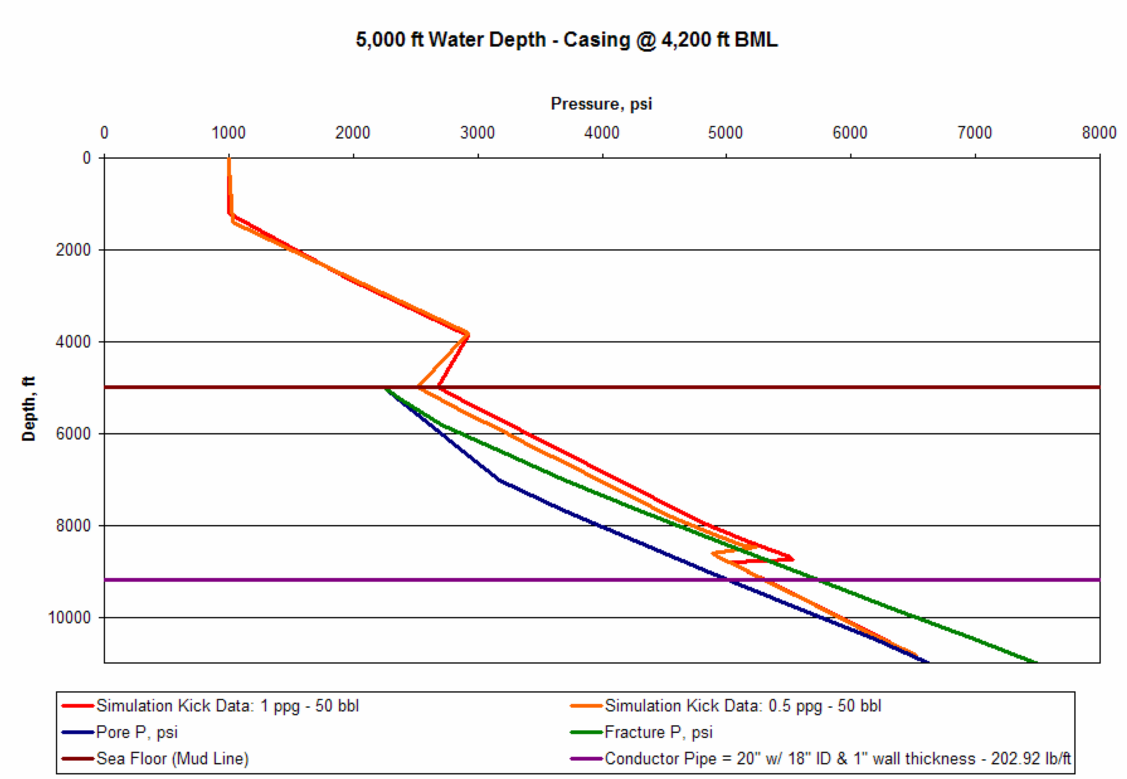

Fig. F6 – Pressure @ Top of Kick in Runs CS6a and CS6b

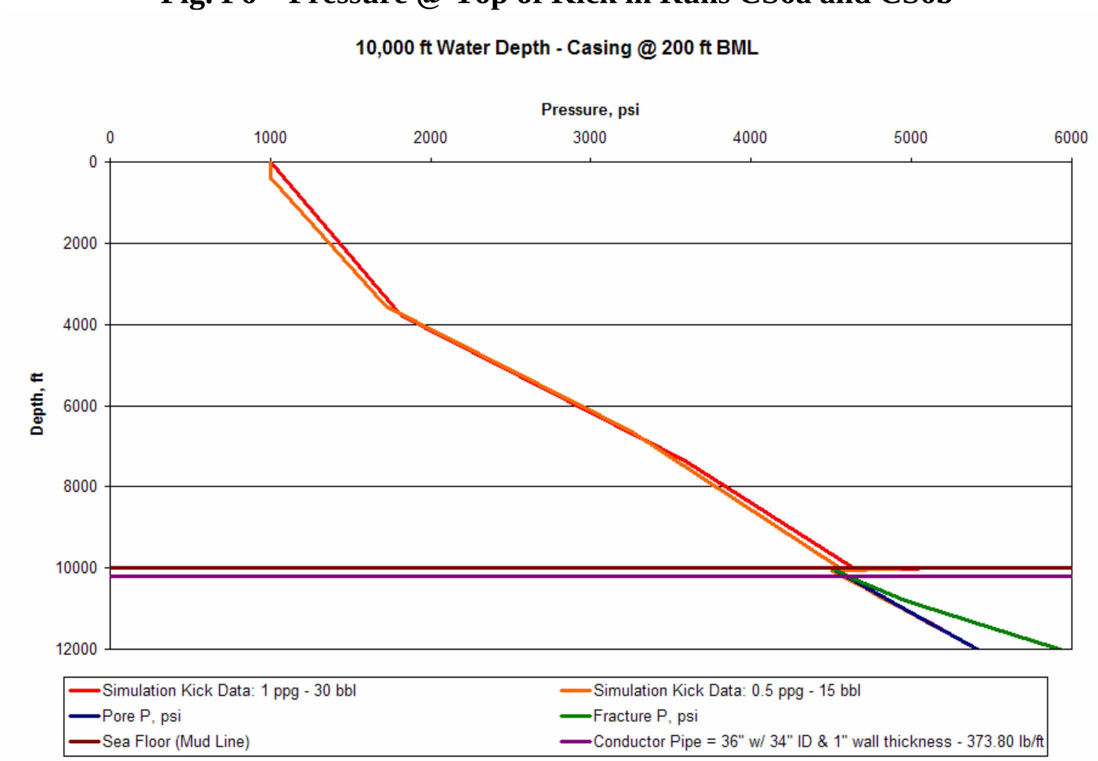

Fig. F7 – Pressure @ Top of Kick in Runs CS7a and CS7b

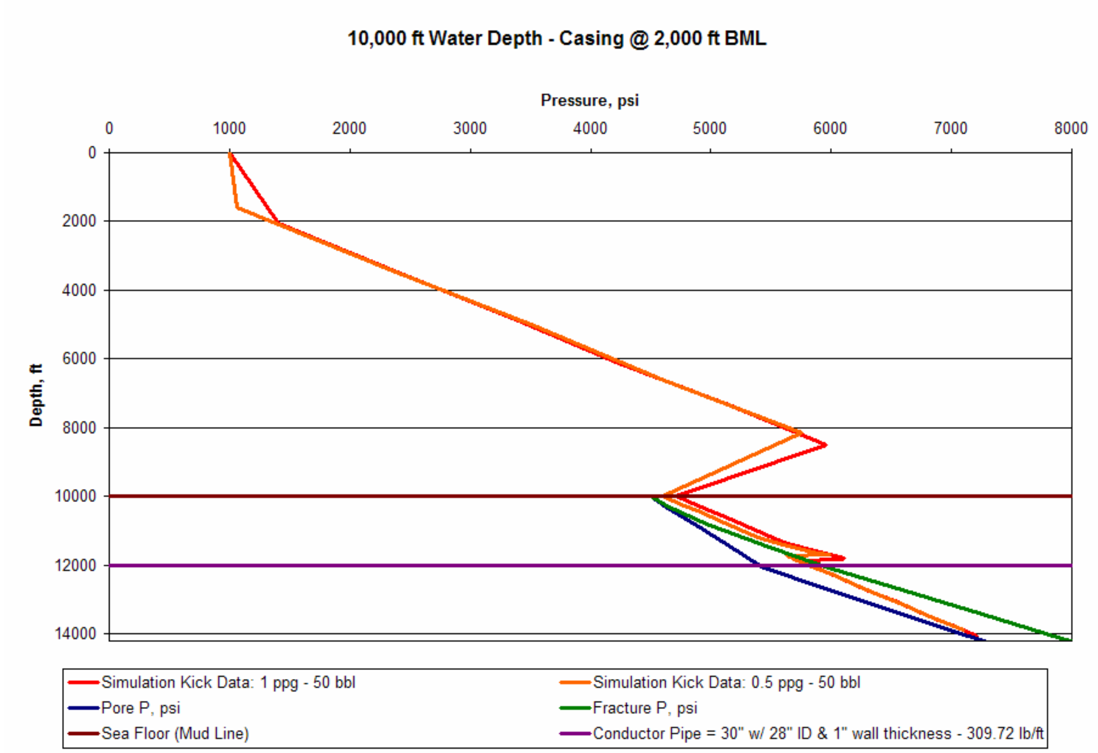

Fig. F8 – Pressure @ Top of Kick in Runs CS8a and CS8b

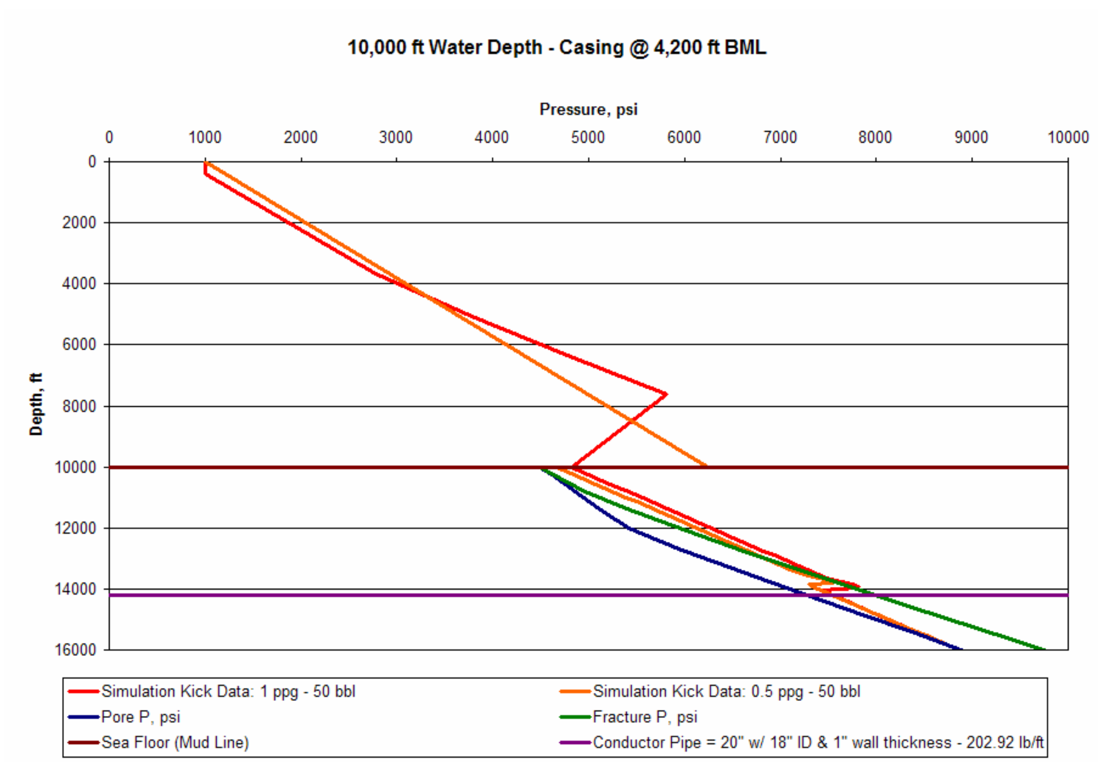

Fig. F9 – Pressure @ Top of Kick in Runs CS9a and CS9b

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