1.0 INTRODUCTION

1.1 Background of Study

Cementing is an integral and a necessary aspect of drilling oil and gas wells. Cement is used to protect casing strings and as zonal isolations for production purposes as well as to solve various holes problems. In order to perform the cementing process, cement slurry must be carefully designed to fulfill the requirement of the reservoir condition.

The designing process of cement will need some mixtures of additives to make the cement slurry performed better under the down hole. Additives can include accelerators and retarders, which related to time of the cement to hardened. In order to decrease or increase the density of the cement, lightweight and heavyweight additives are added. Additives can be added to transform the compressive strength of the cement, as well as flow properties and dehydration rates.To Extenders can be used to expand the cement, and antifoam additives can be added to prevent foaming within the well.

However, all the additives and cement cannot be simply mixed to form good slurry. A lot of factors must be considered. The design of the cementing job must be done properly to prevent big lost including life. This paper will be focusing specifically to a high pressure – high temperature (HPHT) reservoir. A software called OPTICEM which is one of the landmark software will be used in order to perform the simulation.

OptiCem software calculates real-time equivalent circulating densities (ECDs) using actual job volumes, rates and fluid densities. Using the software, more realistic simulator and rheology models can be obtained. OptiCem software compares planned data with actual job data, giving operators the information they need to adjust the original displacement schedule, monitor the location of the fluids during the job, and generate a detailed post-job report. Using the optional OptiCem module, operators can simulate jobs while they are being completed — and adjust displacement rates and pump speeds for optimum results.

Overall of this project will discuss in detail on how to perform cementing design and evaluation of additives control by using landmark software at HPHT condition.

1.2 Problem Statement

1.2.1 Problem Identification

How to avoid kick and losses from happen when performing cementing job?

How to monitor a well from time to time?

How to optimize cost and safe time?

In order to design a cement slurry, a lot of factors need to be taken into account. These are some of the list of properties that need to be discovered in performing the cementing design process:

- Pumpability of the cement
- Mixing condition including additives
- Slurry design
- Displacement of fluid from top to bottom

All of these properties must be looked extra carefully when it comes to a High pressure and High Temperature (HPHT) condition. Cost is the most important thing that needs to be looked in any operations. Cementing job is one of the expensive jobs during well design. Poor cement job or damage to the casing (if cementing job is not done properly) can cost a lot of money. Also, the circulation of cement on production casing prevents the ultimate recovery and potential reuse of the casing when the well is plugged and prevents the replacement of casing during the life of the well.

1.2.2 Significant of the Project

This paper will conduct a simulation of cement designing for the purpose of some operations using software that has been used by HALLIBURTON. In HPHT condition, it is not easy to get the best mixtures of slurry. This project will cuts down on the need to travel to remote locations and give the best solution in creating a perfect cementing design.

1.3 Objective and Scope of Study

The objective of this research is to optimize the slurry design by doing a cementing job simulation using landmark software or to be specific, OptiCem software. Here are the list of the objectives that will be achieved:

- **Save time and money**
  By identifying potential difficulties and tune the cementing design before the pumping begins, using Cementing-OptiCem tools increases the likelihood of a successful, cost-effective operation.
- **Optimizes safety**
  Simulates the job while it is actually going on, letting you adjust the displacement rate as needed and telling you how fast you can safely pump. Because that information can be transmitted to another location and monitored there, OptiCem cuts down on the need to travel to remote locations. One person can handle several jobs indifferent parts of the world all from one central control center.OptiCem also lets you see ECD in real time, enabling you to pump as fast as safely possible

2.0 LITERATURE REVIEW

2.1 Investigation of Drilling Fluid To Maximize Cement Displacement Efficiency. (T.R Smith,Shell Canada Ltd. October 1991)

One of the most important functions of a primary cement job is to provide a hydraulic seal in the casing/borehole annulus.to accomplish this, it is necessary to remove or displace the drilling fluid with a cement slurry. There are many factors which will affect the successful placement of a cement slurry. One of the factors which has been least investigated in either laboratory or field operations is drilling fluid properties.the drilling fluid must be mobile and circulatble before the cement is pumped into place. The drilling fluid used to drill a well is usually selected for its rheology,filtration control,or formation inhibition properties.prior to cementing the wellbore, minor adjustments are often made to the properties of drilling fluid such as thinning or dispersing to lower the viscosity. The investigation concentrates on how the drilling fluid properties affect the displacement efficiency.

2.2 High-density elastic cements applied to solve HPHT challenges in Sount Texas (Barry Wray, Cimarex Energy; David Bedford,Lennox Leotaud and Bill Hunter,Halliburton, November 2009)

Well cementing operations in South Texas tend to present a number of challenges to those responsible for constructing oil and gas wells. For instance, the temperatures and pressures at which the cement needs to be placed can be extreme, routinely exceeding bottomhole static temperatures of 300°F and pore pressures requiring fluid densities of 15 lbm/gal or greater to maintain well control. These extreme conditions can present challenges not only during placement of the cement slurry in the wellbore but also later to the set cement sheath during the life of the well.

To effectively meet these challenges, well operators in South Texas have been using high-density cements that have been mechanically modified so the set cement will be more elastic and resilient. Advanced diagnostic software is used to predict well situations where these cements are required.

Currently, high-density elastic cements (HDEC) have been placed in more than 40 wells in southern Texas, and the use of these sealants combined with diagnostic software has become routine.

This article discusses the challenges cementing high-pressure, high-temperature (HPHT) wells in South Texas, then details the best practice life-of-the-well solutions that have been applied.

Challenges during the operation in HPHT wells from this paper:

1. Insufficient borehole pressure integrity, especially when cutting through depleted zones intermingled with higher-pressure intervals. Shales and/or sands weakened by depletion, leaking faults or unfavorable rock properties result in lost returns when mud weights are close to pore and fracture pressures. In one field, for example, oftentimes the target sand is normally pressured with overpressured shales above and below the sand, with some faulting present. Setting a casing string to isolate normal-pressure zones from high-pressure zones can be problematic if the faults exist at the casing shoe and the cement sheath does not provide a good hydraulic seal. Additional casing strings are often set to allow drilling to continue with narrow margins between pore- and fracture-pressure profiles. These narrow margins can create potential well control issues while construction of the well is in progress.
2. Difficult to select process for the drilling fluids to use in these wells. Oil-based mud (OBM) systems provide definite advantages, generally delivering improved shale stability and clay control, reduced pore-pressure transmission, less differential-sticking tendencies, higher rates of penetration, and better lubricity to minimize torque and drag.

3. These fluids are often costly due to the disposal,lost circulation issues and regulatory /environmental consideration. Therefore, when there are small differentials between pore pressure and fracture-initiation pressure, operators in South Texas prefer to use conventional water-based mud (WBM) below the intermediate casing string to better combat losses and hole ballooning, even though larger washouts are possible with WBM. Hole ballooning is defined by the walls of the well expanding outward because of the increased pressure during pumping. When pumping stops, the walls contract and return to normal size, forcing excess mud out of the wellbore.
4. The largest specific challenges these conditions create for those tasked with placing an effective cement seal in HPHT wells are High equivalent-circulating densities (ECDs) are created when the densified fluids required for well control purposes are pumped into the well, often leading to formation breakdown, followed by annular fluid loss in the fractures created that can potentially lead to well-control issues and after high-pressure well stimulation and production, casing failures can occur if the cement sheath that has been placed is incomplete or does not possess the requisite mechanical properties to withstand the high differential pressures to which it is subjected.

2.3 Cement Fatigue and HPHT Well Integrity with Application to the Life of Well Prediction

Conditions in HPHT wells are particularly challenging, and little is known about the fatigue of cement and the performance of the casing - cement interface in HPHT wells. Drill string-induced vibrations and changing pressures and temperatures cause damage at the casing-cement interface by forming micro annuli, and the accumulation of that damage can lead to a loss of well integrity and well failure. Tubulars used in HPHT wells are tested under simulated borehole conditions prior to field

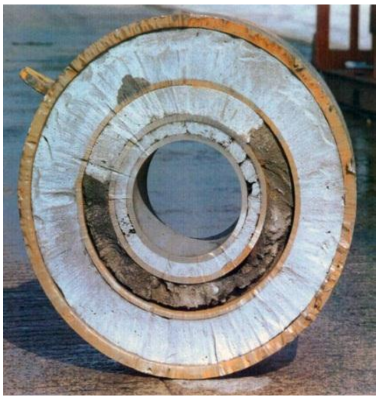

Figure 1 : Micro annulus inside casing

application. Cement slurries and cement properties are also measured, but none of the known methods are able to evaluate the life of the well based on actual wellbore parameters. Even less information is known on the fatigue of cement under cyclic loading under HPHT conditions

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2.4 Ensure long-term zonal isolation in harsh environments (Schlumberger)

Well cements are permanently exposed to downhole conditions. Above about 110 degC [230 degF], the commonly used Portland cement may shrink, lose strength, and gain permeability. This deterioration can be minimized or even prevented by adding at least 35% silica by utilizing cements engineered for the HPHT environment.Even if zonal isolation is initially adequate, changes in downhole temperature and pressure can crack or even shatter the cement sheath; radial pressure/temperature fluctuations can create a microannulus. These concerns are particularly significant in deep, hot wells and thermal-recovery wells.

2.5 The main functions of drilling fluids. (Erik Sofge, May 2010)

The main functions of drilling fluids include providing hydrostatic pressure to prevent formation fluids from entering into the well bore, keeping the drill bit cool and clean during drilling, carrying out drill cuttings, and suspending the drill cuttings while drilling is paused and when the drilling assembly is brought in and out of the hole. However it is also been used as a medium to kill a well. In many cases, when drilling mud is "waded up" to offset a sudden increase in pressure coming from the subterranean formation, the mud is released deep in the well, through holes in the drill bit itself. When the well is being sealed completely, as opposed to using the mud to make slight pressure adjustments during drilling or pumping, it's called "killing" the well. The top kill is generally a less desirable version, where the kill happens from the top down, with mud forced into the kill lines built into the blowout preventers.

However the mud is applied, from above or below, it is done slowly, and carefully.

2.6 Drilling mud composition (Emmanuel Awona, November 2011

Composition of a typical bentonite gel water based mud ,density 1300kg/m3. Components added to 1 barrel of water : (bbl=barrel, pps=pounds per barrel); CMC :(carboxymethylcellulose). Composition of a typical oil based mud density 1318 kg/m3 , salinity 22.5%, oil to water ratio 65:35. components combine to give a total volume of one barrel.(bbl: barrel; ppb:pounds per barrel; gpb: gallons per barrel) .Mud in this paper is used to kill the well to prepare for the cementing operation. Modern-day drilling mud is typically a water-based mixture of heavy clay minerals and synthetic additives. The minerals provide the weight, which can range from 9 pounds per gallon, to as much as 12 or 14 pounds (water weighs about 8 pounds per gallon). The additives allow the mud to maintain a consistent density and composition whether it's sitting in a tank on a drilling platform, filling an exposed well head at pressures of 2500 psi and temperatures of 30 F, or squeezing into the narrow base of the well, where conditions could be closer to 9000psi,200F.

2.7 Physical Properties of Drilling Fluids at High Temperatures and Pressures (Fisk, J.V., Jamison, D.E., Baroid Drilling Fluids,December 1989)

Physical properties – at high temperatures and pressures, rheological and dynamic filtration properties are presented for water and oil based drilling fluids. The physical properties were obtained at temperatures of 400 degree F and pressure of 15000 psi. The temperature effects on the viscosity of oil muds. The dynamic filtration rates of drilling fluids are greatly affected by solid plugging the pore in the formation. Temperature and pressure affect dynamic filtration by changing the dispersion of the solid in the solid

2.8 Density of drilling fluid used during drilling or any well completion.

Density - Mud density or also called as mud weight is measured by means of a mud balance. The weight of water is 8.33 ppg. The mud weight can be increased by adding barite (barium sulphate). Barite has a specific gravity of between 4.2 – 4.3. Mud weight is really important to know in order to prevent kick or losses.

2.9 Flow regimes of drilling drilling fluid.

Flow Regimes – Flow regimes is a range of stream flows having similar bed forms, flow resistance, and means of transporting sediment. Usually in oil and gas we refer as laminar and turbulent. The process of mud removal for primary cementing process can be achieved in these two flow regimes. Most of the research papers claim that in order to overcome the mud channeling in the lower side of the inclined annulus, the turbulence flow has to be created in that section while pumping the cement. Turbulent flow has the chaotic motion of the fluid particles which eventually can reach the narrow side of the casing-casing or casing-open hole annulus and make the mud that settled down in that side to move, breaking the gel of the mud. In order to have turbulent flow in the annulus side we have to create a high velocity profile in that region. The turbulence of the flow regime is highly affected by the flowrate used, the geometry of the hole and the rheological properties of the cement.

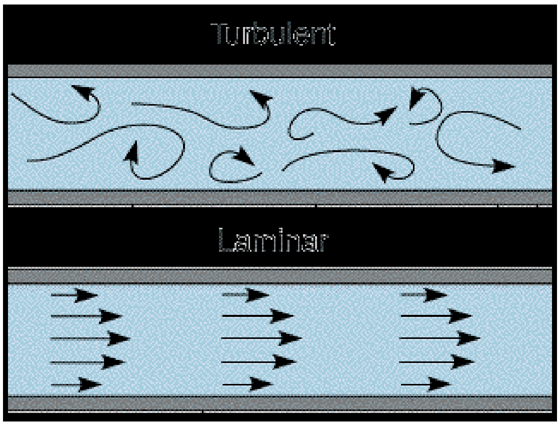


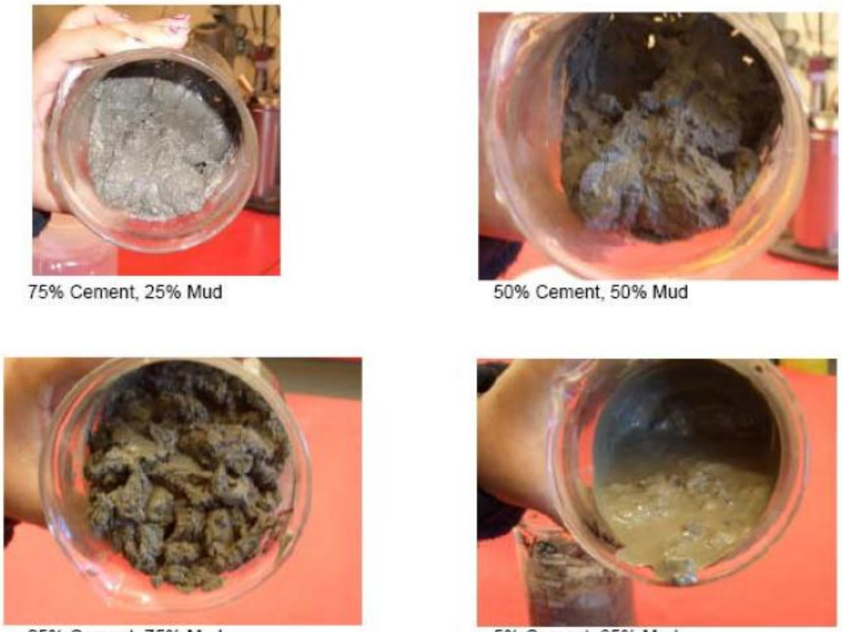
Figure 2:Turbulent and laminar flow pattern.

2.10 Equivalent Circulating Density (ECD)

ECD is the effective density exerted by a circulating fluid against the formation that takes pressure drop, gravitational force and true vertical depth into the ECD calculation. The ECD is important in avoiding kicks and losses, particularly in wells that have a narrow window between the fracture gradient and pore-pressure gradient.

- Rheological properties

Reliable prediction of ECD in HPHT wells requires the use of temperature and pressure dependent rheology and density. The pressure and temperature dependence of rheology can be obtained from laboratory measurements at HPHT conditions of the actual mud system or from a model that is developed based on data from similar mud systems. From an article regarding rheological properties, says it is important to keep the mud and cement fluids seperated when cementing the wells in NZ field since mixtures may result in extremely high viscosity fluids. Rheologies of most of the mixed ratios of mud and cement tested were not measurable in standard rheometers found in field labrotary. High friction pressures that occurred will contribute in the factor of abnormal cementing job pressures.



75% Cement, 25% Mud
50% Cement, 50% Mud
25% Cement, 75% Mud
5% Cement, 95% Mud

Figure 3 : Abnormal cementing job pressures

- Thickening time

A measurement of the time during which a cement slurry remains in a fluid state and is capable of being pumped. Thickening time is assessed under simulated downhole conditions using a consistometer that plots the consistency of a slurry over time at the anticipated temperature and pressure conditions. The end of the thickening time is considered to be 50 or 70 Bc for most applications. Thickening time is really an important factor for cement. Adequate thickening times are required for a good cement job. Excessive waiting time will provide a weak support which can risk the well structure and severely damage the subsea head equipment.

- Circulation rate

Circulation rate of cement to displace all mud in the wellbore will give quite a big impact on the displacement process. The high yieldpoint cement required a flow rate in excess of 22,8 dm3/a (8.5 Bbl/min.), a rate which was unachievable. The moderate yield point cement required a rate of 15.9 dm3/s (6 Bbl/min.) while the low yield point cement required a flow rate of around 13.0 dm3/s (5 Bbl/min.)

- Geothermal gradient

Geothermal gradient is the rate of increasing temperature with respect to increasing depth in the Earth's interior. Away from tectonic plate boundaries, it is **22.1°C per km of depth** (1°F per 70 feet of depth) in most of the world. As we go deeper to the ground,the temperature will increased. At HPHT, the temperature that will be studied will be around 300F and above. Temperature is one of the factors in designing a cement.

- Pore and fracture pressure

It is well known that in the high temperature and high pressure condition case of wells the pore and fracture windows are narrow. Managing the equivalent circulating density (ECD) becomes extremely important as well as challenging. In the presence of these narrow windows, precise management of the ECD is the difference between not fracturing the formation and not allowing influx from the well.

In high-temperature and high-pressure wells (HPHT), it often becomes very difficult to predict the ECD based on some assumed mud properties which end up either over- or under-predicting the actual values. Unfortunately, in wells with narrow margins both situations end up being potentially disastrous; causing either a lost circulation scenario or a well-control situation.

2.11 Role of cementing in Oil and Gas operation.

Cementing is one of the most critical steps in well completion. It will be used at the end of drilling and in the haste to put a well on production, rarely is the time and commitment taken to get a good job. However, usually, the cementing contractors spend significantly more time correcting it or battling the effects of a bad cement job.

Cement fills and seals the annulus between the casing string and the drilled hole. Three general purposes that can be extracted: (1) zone isolation and segregation, (2) corrosion control, and (3) formation stability and pipe strength improvement. Cement can forms a nearly complete impermeable seal from the slurry. It depends on some components and additives that are used to make the cement slurry. This will determine the properties and behavior of the slurry.

Cement particles has a direct relationship with how much water is required to make a slurry without producing an excess of water at the top of the cement or in pockets as the cement hardens. The crystals seen in set cement include:1 C3S - tricalcium silicate, C2S – dicalcium silicate, C4AF - tetracalcium aluminoferrite, C3A - tricalcium aluminate, MgO - periclase or magnesium oxide, and CaO - free lime.

Not all cements, even those made from the same components, will react in the same manner when mixed with water. Basically, the differences are in the fineness of the grind of the cement, impurities in the water and in some minor additives added during the cement manufacturing process.

Figure below gives the API designated classes for cements. These classifications of cement were in response to HPHT downhole conditions. Note that the useful depths given in the data are derived from average pumping times of neat (no additives) cement for average temperatures involved at these depths. Actual well environment controls the limits of the cement. Also, additives such as accelerators and retarders can be used to modify the behavior of the cement. In this manner, a class H cement, for example, can be used to

much greater depths than the 8000 ft limit seen in the table.

Table 1 : API Cement Classes (API RP 10-B)**)**

Class	DEPTH	CONDITION
A	**Surface -6000ft**	Special properties are not required.
B	**Surface -6000ft**	Require moderate to high sulfate resistance.
C	**Surface -6000ft**	Require high early strength.
D	**6000ft-10000ft**	High temperatures and pressures.
E	**10000ft-14000**	High temperature and pressures
F	**10000ft-16000**	Extremely high temperatures and pressures
G	**Surface-8000ft**	Can be used with accelerators and retarders to cover a wide range of well depths and temperatures.
H	**Surface-8000ft**	Can be used with accelerators and retarders to cover a wider range of well depths and temperatures.
J	**12000ft-16000ft**	Extremely high temperatures and pressures. It can be used with accelerators and retarders to cover a range of well depths and temperatures.

2.12 Properties of cement (Servicio de Pozos, November 2010)

2.12.1 TIME pumpability (thick)

The time pumpability of grout is the time for the cement slurry can be pumped and displaced within the annular space (the slurry is pumped during this time.) The grout must have sufficient time to be:

- Mixed
- Pumped into the pipe.
- Scroll through the drilling fluid until it is located where required.

Usually 2-3 hours of pumpability time is sufficient to allow operations to be completed. The time is enough to cover any delays or interruptions in cementing operations. Pumpability time required for a particular operation should be carefully selected so that the following operational activities are met:

- The grout should not be set as you start to be pumped.
- The grout should not stay smooth for long, because it could be contaminated with the formation fluids or other contaminants.
- cementing operations should not take too long in a drilling operation.

Conditions at the bottom of the well have a significant effect on pumpability time. It might be an increase in temperature, pressure or reduce in fluid loss could reduce the pumpability time. These conditions should be simulated on the stage of design and testing of grout in the lab before they develop any operation in the well.

This project will use Opticem cementing software in performing the cementing design.

2.12.2 Slurry density

The standard density of the slurry can be altered to meet specific operational requirements (a formation that has a low fracture gradient may not withstand a hydrostatic pressure grout whose density is around 15 lb / gal). The density can be altered by changing the amount of water or using aditivospara mixing the grout. The density of many cement slurries ranges from 11 to 18.5 lb / gal (ppg). It should be stressed that this aspect of cement slurries are relatively heavy, knowing that normal pressure gradients of the formations are generally considered equivalent to 8.9 lb / gal (ppg). However, it is inevitable to have a heavy grout (high density), if required to the hardened cement reaches a high resistance to compression.

2.12.3 LOSS OF WATER (WATER-FREE)

The hardening of the grout is the result of the cement begins to hydrate with water mixture. If water is lost from rout before it has been positioned in the annular space,it will decrease pumpability time and water sensitive formations may be adversely affected. The amount of water loss that can be tolerated depends on the cementing operation and the development of the grout.

Forced Cementation requires low values of water loss, because the cement should be injected under pressure that is generated by a plaster and block the perforations. The primary cementing does not depend critically on the loss of water. The amount of fluid lost from a slurry in particular must be determined through a laboratory test. Under standard laboratory conditions (1000 psi of pressure in the filtering test, with a mesh size of 325 mesh)

2.12.4 PERMEABILITY

After the cement has hardened, the permeability is very low.

2.2.5 SLURRY DESIGN

The first concern in designing cement systems for oil and gas wells is to ensure that
the slurries are suitable for field applications. This means that they can easily be mixed and pumped with conventional surface equipment, and placed at the required depth with proper thickening time. The slurry must also remain stable during the whole process. For this purpose, an optimization is carried out for each system. Therefore, Proper slurry design is critical to the success of a cementing job. While some deficiencies may be tolerable in vertical wells, horizontal wells are not forgiving and the highest quality slurry must be used.

2.13 Cement additives (Servicio de Pozos, November 2010)

Many cement grout containing additives, to modify the properties of the slurry and optimize cementing operations. Many additives are known by its trade name used by cementing service companies. Cement additives may be used to:

• Vary the density of the grout.
• Change the compressive strength.
• Accelerating or delaying the time sets.
• Control of filtering and fluid loss.
• Reduce the viscosity of the slurry.

Additives (Extenders or Retarders) can be delivered to the drilling location in granular or liquid state and can be mixed with cement powder or added to water before mixing the cement slurry is mixed. The amount of additives used is commonly expressed in terms of percentage by weight of cement powder (based on each sack of cement weighs 94 lbs.) Many additives affect more than one property and therefore should be carefully used.

2.14 Cementing Design

The first use of cement in the oil industry is recorded as a water shutoff attempt in 1903 in California.2 At first, cement was hand mixed and run in a dump bailer to spot a plug. Pumping the cement down a well was soon recognized as a benefit and a forerunner of the modern two-plug method was first used in 1910.2 The plugs were seen as a way to minimize mud contact with the cement. Although both mechanical and chemical improvements have been made in the cementing process, the original plug concept is still valid. Cement design includes the selection of additives and equipment to remove mud and properly place and evaluate the cement. The cement design depends upon the purpose of the cementing operation. The initial cement is usually to fill the annular space between the casing and the hole from the casing shoe to the surface or a point several hundred feet above the zone that must be isolated. The first cement job is called primary cementing and its success is absolutely critical to the success of subsequent well control and completion operations. When a primary cement job fails to completely isolate the section of interest, repair of the cement job must be done before drilling can proceed.

These repair steps are covered by the collective label of squeeze cementing. In a squeeze job, cement is forced into the zone through perforations, ports in tools, hole produced by corrosion, or through the clearance between casing overlap liners or strings. Although squeeze cementing has become common place, it is expensive and its use can be curtailed through Improved primary cementing procedures.

Cementing design must be done accurately because one mistake can cause a big lost.

2.15 OPTICEM sotware.

Opticem software is one of the landmark software used by Halliburton. It is a cement modeling software which is really a preferable method if compare to others. It is safer and reliable. Other than that,opticem cementing modeling software system can helped in reducing well operation cost.

From one article on how Opticem can reduce operation well cost is during the requirement of cementing job at PERMIAN BASIN.

The customer was drilling a 13,000 ft slim-hole gas well. Drilling the well underbalanced would reduce the rig time and overall well cost. The customer asked Halliburton to design a cementing program that would provide good zonal isolation while elliminating the need for 16.0 ppg mud and a heavy weighted spacer.

Halliburton used its OptiCem™ cementing modeling software system to design a cementing program to meet the challenge. After designing and testing the cement slurry which incorporated Halliburton's Super CBL additive for gas migration control, the slurry properties and well condtions were input into the OptiCem software. A pumping schedule with rates, surface pressures, equivalent circulating densities (ECD), and backpressures necessary to maintain the required ECD was generated. The OptiCem RTT™ software could then be used to monitor the job in real time and make adjustments if necessary. The cementing design and procedure were reviewed with the customer, and operations proceeded as planned. The well was cemented using a pumping schedule designed with Opticem software,and the customer did not have to use 16.0 ppg mud and heavy-weight spacers to achieve good zonal isolation. This allowed the customer to reduce rig time by 1-1/2 days and resulted in a mud cost savings of $60,000. The estimated economic value to the customer was $90,000.

In conclusion, this software is really reliable in reducing the cost.

Opticem provides a good suggestion and method in order to work safely in danger and risky area. This is one example from BP cement case which has caused 11 oil rig workers and millions of barrels of oil spill into the Gulf of Mexico. It was BPs deepwater horizon oil well.

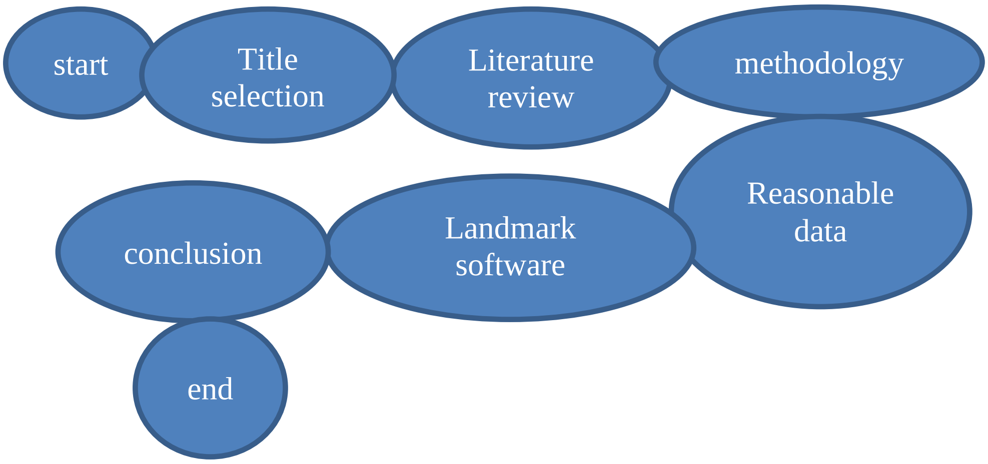
An Opticem test has been done 5days before the incident. From the case, Halliburton's point of view based on the Opticem cementing simulation suggested BP to use 21 Centralisers. Because of some technical problem occurred, BP proceeded with the drilling, with only six centralisers, deciding another known technique of injecting cement in other places would work. (Leo King,November 2010)

From this article, it shows that Opticem is a reliable cement simulator and its proven that it has suggested the right thing and the incident must not supposed to occur.

3.0METHODOLOGY

3.1Research Methodology

This is the overall Research methodology that are used for the project.



3.1.1 Sources gathering

For research part, journals, books, and technical papers will be used to get a better understanding about this project.it will make the author to be familiar and a clear view about the research scope that will be carried out. Most of the sources are from Society of Petroleum Engineers (SPE) technical papers that can be found online. other than that, oil and gas news has been used as well for the source. Book related to cementing in oil and gas operation from University of Technology Petronas library has helped this research a lot.

After the reading has been done, a Gantt chart has been drawn which consist of several milestone and project activities so that the time will be allocated in the right way.

3.1.2 Analysis

The existing cementing design will be studied in order to find the weakness or certain features that they are lacking off so that it can be improved. All information will be compared and analysed in detail. Afterwards, this paper will reveal a better solution for current problem such as safety and cost.

3.2 Project activities

To finish this research, the most important thing is getting familiar with software used. In this case, it is OPTICEM which is under landmark software. A manual for the software has been given to the author. It will be used when it comes to simulation lab session. A post-graduate student has been assigned to help the author with the lab simulation. This can reduce the time for the lab session since the post-graduate student are good with the cementing knowledge.

One of the main objectives is to design a cement program with safety optimization and to prevent kick and losses from happen. A control of ECD must be done accurately by using opticem software. In order to perform casing design using the software,data is needed.

1) **Class of Cement**

First step is determining which class of the cement suitable for the HPHT condition. The class of cement can be refer from one of the literature review that has been mentioned earlier.

2) **Rhelogy of the Cement**

The next step in our methodology is to determine the rheology of the cement, because the calculations of determining the flow regime and frictions caused by the fluid vary depending on the rheology type of the fluid, in our case cement.

The Fann viscometer is a concentric cylinder viscometer capable of measuring the shear stress at two or more shear rates. This is by far the most common device used at the rig site and in the laboratories to measure the rheological properties of drilling fluids. The Fann viscometer was designed specifically for use with drilling fluids and the various constants in the rheological models can be measured rather easily.

Rheological models are intended to provide assistance in characterizing fluid flow. No single, commonly-used model completely describes rheological characteristics of drilling fluids over their entire shear rate range. Knowledge of rheological models combined with practical experience is necessary to fully understand fluid performance. A plot of shear stress versus shear rate (*rheogram*) is often used to graphically depict a rheological model.

From the plot we get through the Shear stress vs. Shear rate we can determine the rheology of the cement that will be used in our project. Traditionally, oil industry uses the Bingham and Ostwald de Waele (Power law) models to represent drilling fluid as well as cement slurry behavior. Also, standard API methods for drilling hydraulics assume either a Power Law or Bingham Plastic model. In reality, most drilling mud and particularly cement slurry correspond much more closely to the Modified Power Law or Herschel-Buckley rheological model. This distinction is particularly important for annular geometries typical of normal drilling conditions where shear rates are usually low. In these situations Power Law model underestimates while Bingham Plastic model overestimates frictional pressure drops. Several complex relationships for Herschel-Buckley fluids are difficult and even impossible to evaluate analytically. Herschel-Buckley rheological model presents more adequate rheological parameter, but the formulation and solution to it holds very sophisticated and detailed approach. That is why my calculation will be based on the Bingham Plastic rheology model of the cement, same as the drilling mud rheology.

The drilling engineer deals primarily with the flow of drilling fluids and cements down the circular bore of the drillstring and up the circular annular space between the drillstring and wellbore. In order to develop mathematical relation between flow rate and flow regime of the cement, the following assumptions are made:

- **The casing to be cemented is placed concentrically in the casing or the hole**
- **The sections of open hole are circular in shape and of known diameter**
- **The cement is incompressible**
- **The flow is isothermal**

Cement flowing in a casing or a concentric annulus does not have a uniform velocity. The fluid velocity, immediately adjacent to the pipe walls will be zero, and fluid velocity most distant from the casing walls will be at maximum level.

3) Equivalent circulating density

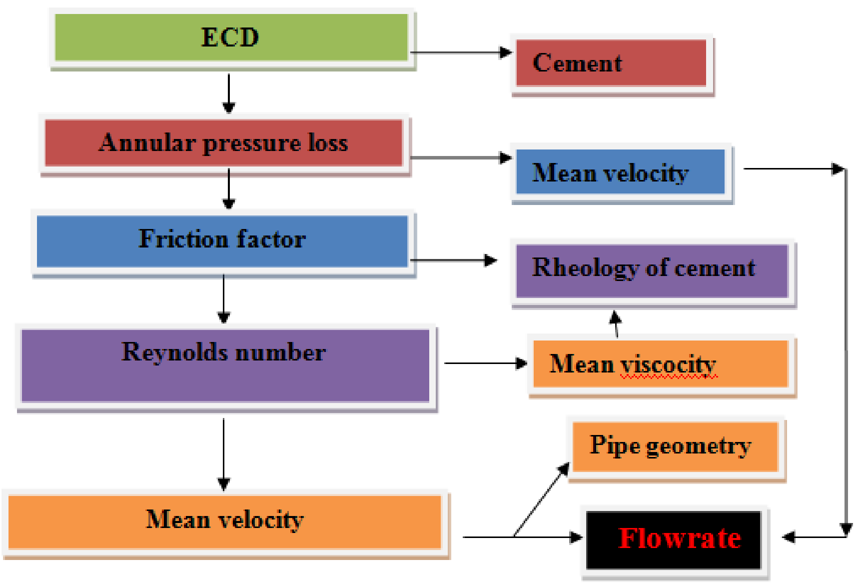
Pump pressure and its hydraulic power are not the only parameters for determining the maximum flowrate for the system; it is also bounded by the fracture gradient of the formation being cemented. The Equivalent Circulating Density (ECD) of the flowing cement should not exceed the fracture gradient in order to prevent the fracturing the formation which can eventually lead to a loss of the cement and mud, especially in the low pressured zones.

ECD = CW + Pt.ann / 0.052*TVD

Where,

CW = weight of the cement, ppg; Pt.ann = total annular pressure losses, psi

TVD = true vertical depth of the cemented depth, ft



As we can see from the chart ECD eventually ends up depending on the Flowrate as well as Reynolds number which determines the flow regime of the cement slurry pumped. Thus to meet the objectives of my project I will mainly focus on choosing the right Flowrate of the system while cement slurry is pumped and manipulating it as to get the proper results. It is more challenging to change the rheology of the cement as well as almost impossible to change the geometry of the wellbore and casings used as the Reynolds number and friction factors depending on rheology indeed.

4) **Landmark software**

In the landmark software, lots of data will be inputted. The data used is not from a real field data but it's a reasonable data that was found from internet. The data has been changed to make it parallel with the topic which are for HPHT well. the depth was set to be at 20000ft which shows that it is a high pressure well and the Temperature was set to be at more than 400 degree Fahrenheit which indicates it is a high temperature well. The landmark software will shows the plot of downhole pressure.

The cementing procedure then will be simulated by inserting the obtained value into the Landmark software. The results will be recorded; analyzed and appropriate conclusions will be made.

The corrections will be made for the calculations and/or the procedures if the outcome expected will fail or will not meet the objectives of the project. The new results and criteria will be checked through the Landmark software of Halliburton again.

5) **The effect of silica fume**

It is found that silica fume, also known as **microsilica** or **silica dust**, has been world widely used for many years in the area where high strength and durable concrete were required. Silica fume improves the properties of both fresh and harden concrete. Since there are a lot of advantages can be found from the addition of silica fume in a cement mixture, landmark software will help to enhanced the reason that silica fume must be used world widely. The result will be studied and analyzed further.

The summary

- Silica fume reduces the permeability of the **concrete**. Water and chemicals ingress are thus reduced.

- The ability of high C3A cement to complex with chlorides results in the formation of insoluble compound, able to reduce the mobility of free chloride ion to the reinforcement-concrete surface.

3.3 Key milestone & Gantt chart

No	Detail / Week	1	2	3	4	5	6	7		8	9	10	11	12	13	14	15
1	Project work continues								M								
2	Submission of progress report								I								
3	Project work continues								D								
4	Pre-SEDEX																
5	Submission of draft report								S								
6	Submission of dissertation (soft bound)								E								
7	Submission of technical paper								M								
8	Oral presentation																
9	Submission of dissertation (hard bound)																

Legends:-

Project activities

Key milestones

3.4 Tools

The tools that is needed for this project

- **i. Training manual for Wellplan software.**
- **ii. PC installed with Wellplan software.**
- **iii. Wellplan software expertise.**

This project is totally based on Wellplan software. The software needs a licensed key which is quite expensive. However, this university's PC has provided the software. The manual for opticem is required since this software is quite complicated to get familiar.

4.0 Result and Discussion

4.1 Landmark Software start-up

The course of Landmark software of Halliburton has been taken in this university for two weeks that was organized by an Advanced Drilling Engineering lecturer Dr. Reza Ettehadi Osgouei.
The parts that were included in the training were consisted mainly of following suites:

- **Compass**
- **CasingSeat**
- **WellPlan**
- **WellCat**

The topic of this project is "Designing a cement program for HPHT well using Landmark software" and the most suitable Landmark software for me was WELLPLAN Suite which includes OptiCem, that is used to simulate the cementing jobs using various techniques and by manipulating various data, such as:

- **Sequence and rates fluids to be pumped**
- **Shoe tracks**
- **Automatic Rate Adjustments and Safety Factors**
- **Job stages**
- **Cement material requirements (sacks)**
- **Displacement volumes**
- **Fluid Animation when reviewing many job parameters**
- **Hole cleaning during cement job, etc**

4.1.1 Initial/Essential Data Input into the software

My first step started by inputting the data that is essential for the work of the module which is importing a hypothetical well path data to the program. Three values only needed for the software to find out and come up with other needed data to build the right well trajectory. The data are:

- **Measured Depth**
- **Azimuth**
- **Inclination**

Other information is calculated automatically, such as:

TVD (ft)	DLS (°/100ft)	AbsTort (°/100ft)	RelTort (°/100ft)	VSect (ft)	North (ft)	East (ft)	Build (°/100ft)	Walk (°/100ft)

Figure 4 : Information from wellpath editor

All those three data needed has been inputted manually in a section called WELLPATH EDITOR in a software. The TVD was set to be at 20000ft to indicate that this is a high pressure well. The maximum inclination used is 60^{o} and the dog leg is maintained to be 3.05. from study, the dog leg must not be more than 3.05.

Wellpath Editor

Identification

Name: Wellpath Options...

Description:

Well Depth (MD): 20000.0 ft ☐ Generate with Actual Stations

VSection Definition

Origin N: ft

Origin E: ft

Azimuth: 224.84 °

	MD (ft)	INC (°)	AZ (°)	TVD (ft)	DLS (°/100ft)	AbsTort (°/100ft)	RelTort (°/100ft)	VSect (ft)	North (ft)	East (ft)	Build (°/100ft)	Walk (°/100ft)
1	0.0	0.00	0.00	0.0	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
2	600.0	0.00	224.84	600.0	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
3	5200.0	0.53	224.84	5199.9	0.01	0.01	0.00	21.3	-15.1	-15.0	0.01	0.00
4	5315.0	3.53	224.84	5314.8	2.61	0.07	0.00	25.3	-18.0	-17.9	2.61	0.00
5	5413.4	6.53	224.84	5412.9	3.05	0.12	0.00	34.0	-24.1	-24.0	3.05	0.00
6	5511.8	9.53	224.84	5510.3	3.05	0.17	0.00	47.7	-33.8	-33.6	3.05	0.00
7	5610.2	12.53	224.84	5606.9	3.05	0.22	0.00	66.5	-47.2	-46.9	3.05	0.00
8	5708.7	15.53	224.84	5702.4	3.05	0.27	0.00	90.4	-64.1	-63.8	3.05	0.00
9	5807.1	18.53	224.84	5796.5	3.05	0.32	0.00	119.2	-84.5	-84.1	3.05	0.00
10	5905.5	21.53	224.84	5888.9	3.05	0.36	0.00	152.9	-108.4	-107.8	3.05	0.00
11	6003.9	24.53	224.84	5979.5	3.05	0.41	0.00	191.4	-135.7	-135.0	3.05	0.00
12	6102.4	27.53	224.84	6068.0	3.05	0.45	0.00	234.6	-166.4	-165.5	3.05	0.00
13	6200.8	30.53	224.84	6154.0	3.05	0.49	0.00	282.4	-200.2	-199.1	3.05	0.00
14	6299.2	33.53	224.84	6237.4	3.05	0.53	0.00	334.6	-237.2	-235.9	3.05	0.00
15	6397.6	36.53	224.84	6318.0	3.05	0.57	0.00	391.0	-277.3	-275.7	3.05	0.00
16	6496.1	39.53	224.84	6395.5	3.05	0.61	0.00	451.7	-320.3	-318.5	3.05	0.00
17	6594.5	42.53	224.84	6469.8	3.05	0.64	0.00	516.3	-366.1	-364.1	3.05	0.00
18	6692.9	45.53	224.84	6540.5	3.05	0.68	0.00	584.7	-414.6	-412.3	3.05	0.00
19	6791.3	48.53	224.84	6607.6	3.05	0.71	0.00	656.7	-465.6	-463.1	3.05	0.00
20	6889.8	51.53	224.84	6670.8	3.05	0.75	0.00	732.2	-519.2	-516.3	3.05	0.00
21	6988.2	54.53	224.84	6730.0	3.05	0.78	0.00	810.8	-574.9	-571.7	3.05	0.00
22	7086.6	57.53	224.84	6785.0	3.05	0.81	0.00	892.4	-632.8	-629.2	3.05	0.00
23	7200.0	60.00	224.84	6843.8	2.18	0.83	0.00	989.3	-701.5	-697.6	2.18	0.00

Figure 5 : Wellpath editor

Next main data to be inputted are pore pressure profile of the drilled section

Pore Pressure

	Vertical Depth (ft)	Pore Pressure (psi)	EMW (ppg)
1	600.0	223.38	7.17
2	1476.0	580.50	7.57
3	1804.0	732.70	7.82
4	1969.0	810.10	7.92
5	2297.0	962.40	8.07
6	3181.0	1403.00	8.49
7	3279.0	1449.80	8.51
8	3344.0	1479.60	8.52
9	3764.0	1681.50	8.60
10	4505.0	2034.30	8.69
11	4624.0	2176.10	9.06
12	4712.0	2285.50	9.34
13	5108.0	2513.50	9.47
14	5344.0	2762.60	9.95
15	5480.0	2965.50	10.42
16	5680.0	3211.90	10.89
17	5801.0	2738.00	9.09
18	6475.0	3069.40	9.13
19	7355.0	3610.70	9.45
20	7798.0	4071.10	10.05
21	8281.0	4577.00	10.64
22	8767.0	4939.60	10.85
23	9259.0	5363.00	11.15
24	9493.8	5499.00	11.15
25	9600.0	6109.10	12.25
26	10254.0	6791.60	12.75
27	10504.0	6957.20	12.75
28	10743.0	7394.50	13.25
29	11253.0	7774.80	13.30
30	11753.0	8144.70	13.34

Figure 6 : Pore pressure profile

And fracture pressure profile

Fracture Gradient

	Vertical Depth (ft)	Fracture Pressure (psi)	EMW (ppg)
1	600.0	280.52	9.00
2	1476.0	861.80	11.24
3	1804.0	1068.30	11.40
4	1969.0	1182.40	11.56
5	2297.0	1420.00	11.90
6	3181.0	2032.50	12.30
7	3279.0	2120.70	12.45
8	3344.0	2188.80	12.60
9	3764.0	2493.00	12.75
10	4505.0	3030.60	12.95
11	4624.0	3182.80	13.25
12	4712.0	3284.90	13.42
13	5108.0	3584.90	13.51
14	5344.0	3844.90	13.85
15	5480.0	4039.50	14.19
16	5680.0	4287.30	14.53
17	5801.0	3983.90	13.22
18	6475.0	4453.50	13.24
19	7355.0	5146.60	13.47
20	7798.0	5630.80	13.90
21	8281.0	6198.90	14.41
22	8767.0	6585.50	14.46
23	9493.8	7274.50	14.75
24	10254.0	7920.90	14.87
25	10504.0	8114.00	14.87
26	10753.0	8311.90	14.88
27	11253.0	8710.10	14.90
28	11753.0	9109.30	14.92
29	12253.0	9509.60	14.94
30	12503.0	9716.60	14.96
31	12753.0	9924.10	14.98
32	13243.7	10319.80	15.00

Figure 7 : Fracture pressure profile

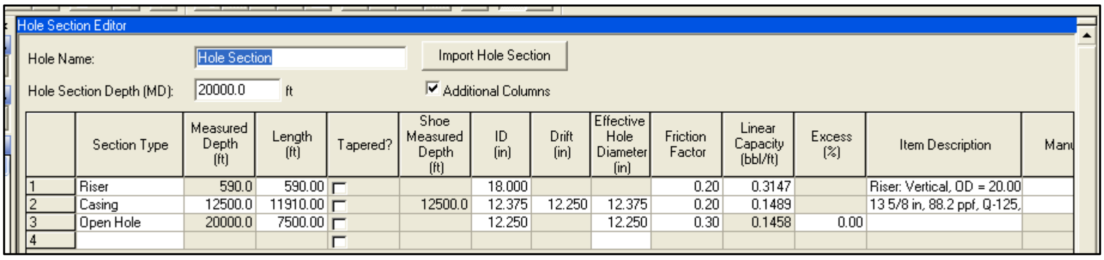
Both of them are inserted in **PORE and FRACTURE PRESSURE** sections of the WELLPLAN suite.

4.1.2 Cementing 9 5/8" casing

Starting from this point we can start cementing our well with 9 5/8" casing running, as the previous casing 13 5/8" production casing is driven into the earth to the vertical depth of 12500ft.

First step is to edit the hole section where the casing will be run and cemented:

In **HOLE SECTION EDITOR,** section type will be defined together with their required specification. The data inputted is not based on real field but a realistic data.



Hole Section Editor

Hole Name: Hole Section | Import Hole Section

Hole Section Depth (MD): 20000.0 ft | Additional Columns

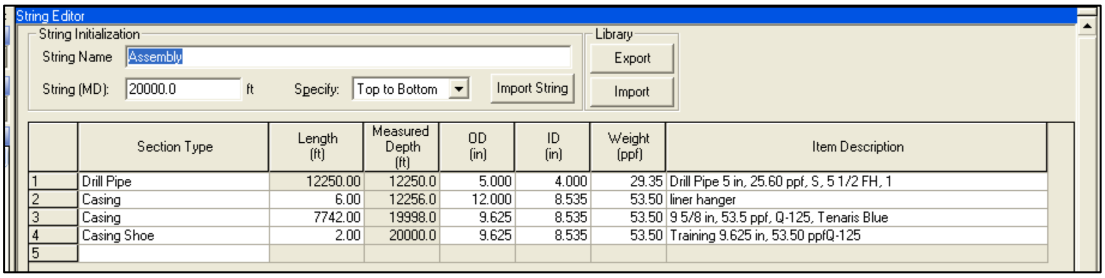
	Section Type	Measured Depth (ft)	Length (ft)	Tapered?	Shoe Measured Depth (ft)	ID (in)	Drift (in)	Effective Hole Diameter (in)	Friction Factor	Linear Capacity (bbl/ft)	Excess (%)	Item Description	Manu
1	Riser	590.0	590.00			18.000			0.20	0.3147		Riser: Vertical, OD = 20.00	
2	Casing	12500.0	11910.00		12500.0	12.375	12.250	12.375	0.20	0.1489		13 5/8 in, 88.2 ppf, Q-125,	
3	Open Hole	20000.0	7500.00			12.250		12.250	0.30	0.1458	0.00		
4													

Figure 8 : Hole section editor

from this section, it shows that 13 5/8” casing was set at 12500 ft and 12 1/4” hole is was drilled until the MD of 7500 ft.

The next step is to edit the string that will be inserted into the new drilled section:

In **STRING EDITOR,** the data are filled as the picture below.



String Editor

String Initialization: String Name: Assembly; String (MD): 20000.0 ft; Specify: Top to Bottom; Import String

Library: Export; Import

	Section Type	Length (ft)	Measured Depth (ft)	OD (in)	ID (in)	Weight (ppf)	Item Description
1	Drill Pipe	12250.00	12250.0	5.000	4.000	29.35	Drill Pipe 5 in, 25.60 ppf, S, 5 1/2 FH, 1
2	Casing	6.00	12256.0	12.000	8.535	53.50	liner hanger
3	Casing	7742.00	19998.0	9.625	8.535	53.50	9 5/8 in, 53.5 ppf, Q-125, Tenaris Blue
4	Casing Shoe	2.00	20000.0	9.625	8.535	53.50	Training 9.625 in, 53.50 ppfQ-125
5							

Figure 9 : String editor

In this section,it shows that the only string that will be inserted into the 12 1/4” hole is 12” liner hanger, 9 5/8” casing with 53.5 poundage with its casing shoe at 20000 ft. Other than that, the drill pipe data is also be inputted as it is one of the component need for circulating all fluids.

At this point,the schematic diagram from surface until depth 20000ft can be viewed as follow.

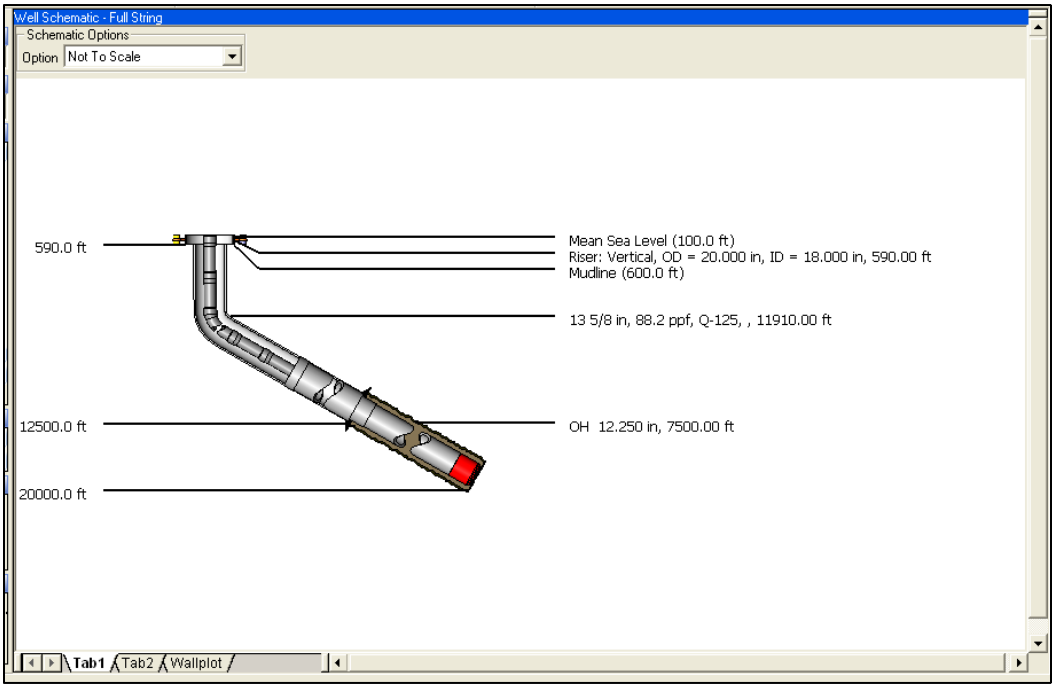


Figure 10 : Well schematic-full string

This is considered as a simple operation,using only riser and liner, since the main point of this project is on the cementing part only. The riser shown has a length of 590ft,casing has 11910 ft and the rest was occupied by open hole.

All the fluids – cement slurries, drilling fluids, and spacer's data was inputted into the section named **FLUID EDITOR** as following:

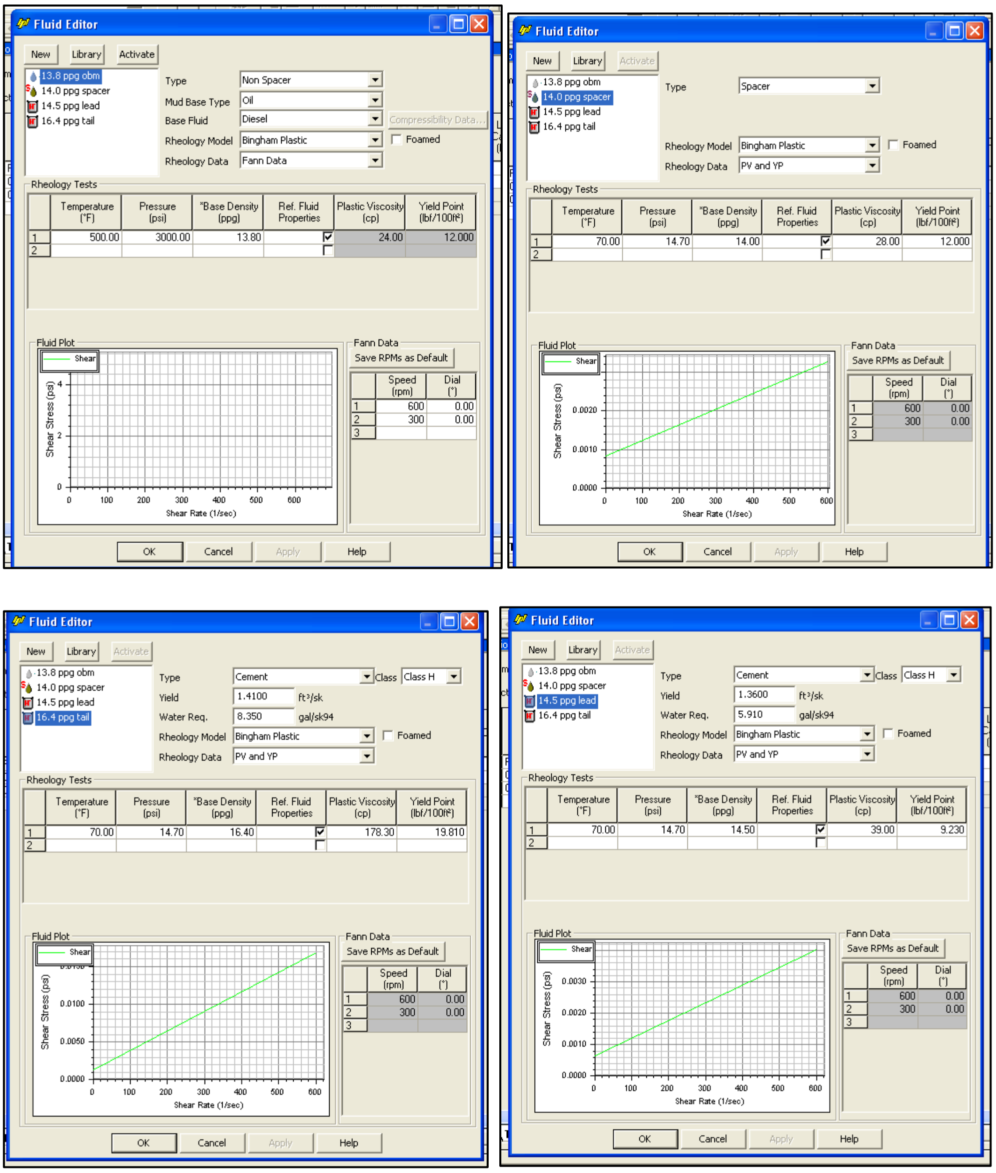


Figure 11 : Fluid editor for normal practice cement

There are only four types of fluid that need to be defined which are mud,spacer,cementing tail,and lead.

Next part is focusing on the Temperature. The Bottom Hole StaticTemperature (BHST) is set to be at 547.75 degree Fahrenheit with geothermal gradient of 4.00 degree Fahrenheit/100ft

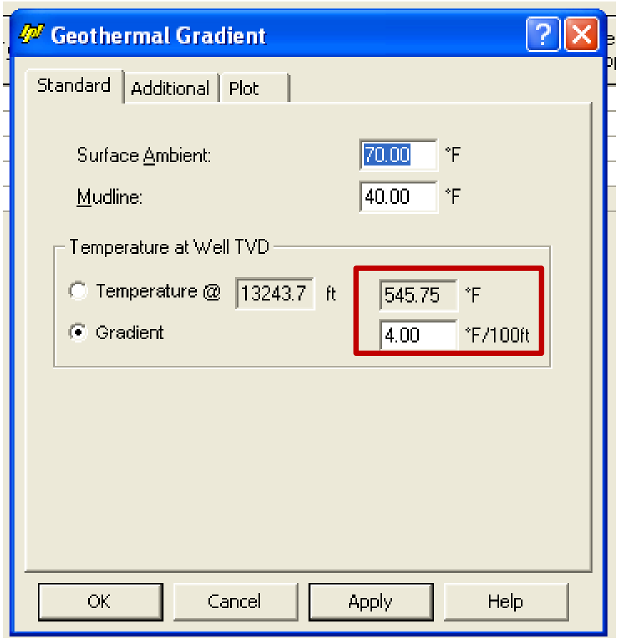


Figure 12 : Geothermal gradient

The Bottom Hole CirculatingTemperature (BHCT) is calculated by this software at ADDITIONAL DATA section.

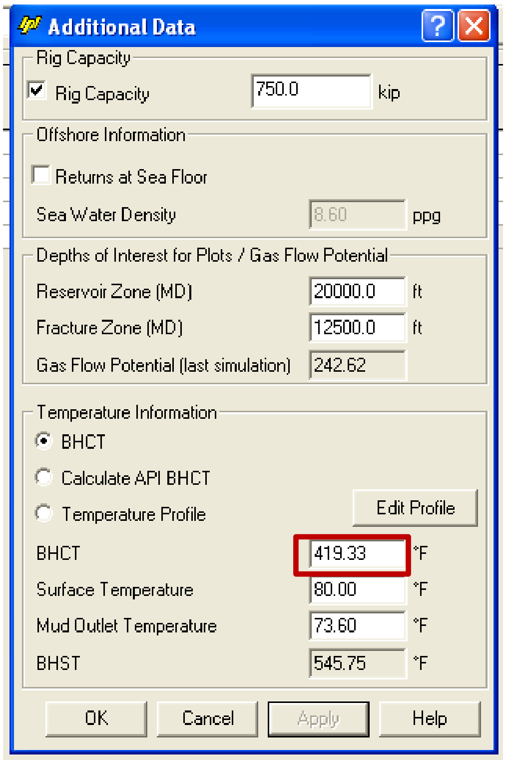
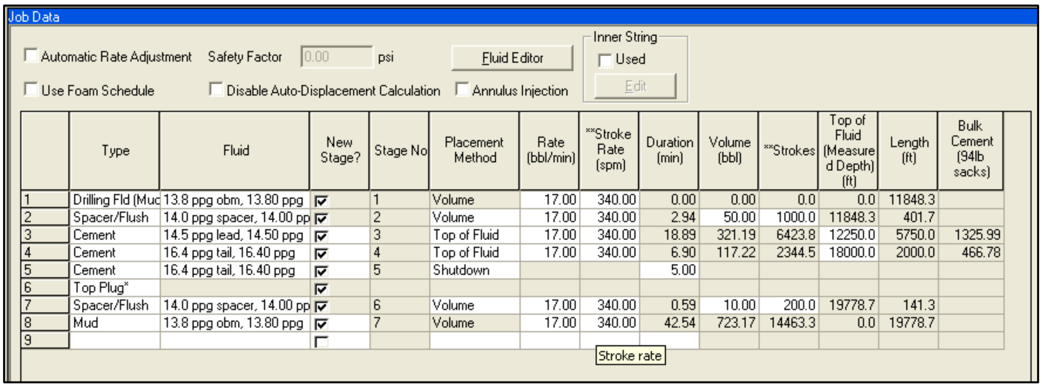


Figure 13 : Additional data

Next step is one of the most important and is called **Job Data**. Here we indicate the sequence of the fluids to be pumped during cementing, together with their respective flowrates, volumes, fluid lengths and tops. The following figure represents the casing Job Data for 9 5/8” casing cementing:



	Type	Fluid	New Stage?	Stage No	Placement Method	Rate (bbl/min)	**Stroke Rate (spm)	Duration (min)	Volume (bbl)	**Strokes	Top of Fluid (Measured Depth) (ft)	Length (ft)	Bulk Cement (94lb sacks)
1	Drilling Fld (Muc	13.8 ppg obm, 13.80 ppg	☑	1	Volume	17.00	340.00	0.00	0.00	0.0	0.0	11848.3	
2	Spacer/Flush	14.0 ppg spacer, 14.00 pp	☑	2	Volume	17.00	340.00	2.94	50.00	1000.0	11848.3	401.7	
3	Cement	14.5 ppg lead, 14.50 ppg	☑	3	Top of Fluid	17.00	340.00	18.89	321.19	6423.8	12250.0	5750.0	1325.99
4	Cement	16.4 ppg tail, 16.40 ppg	☑	4	Top of Fluid	17.00	340.00	6.90	117.22	2344.5	18000.0	2000.0	466.78
5	Cement	16.4 ppg tail, 16.40 ppg	☑	5	Shutdown			5.00					
6	Top Plug*		☑										
7	Spacer/Flush	14.0 ppg spacer, 14.00 pp	☑	6	Volume	17.00	340.00	0.59	10.00	200.0	19778.7	141.3	
8	Mud	13.8 ppg obm, 13.80 ppg	☑	7	Volume	17.00	340.00	42.54	723.17	14463.3	0.0	19778.7	
9			☐										

Figure 14 : Job data for normal practice cement 1st trial

From the table we can see the sequence of pumped fluids, with their respective properties. The flowrate is constant for all the fluids which is 17 bbl/min (714 gpm).

13.8 ppg drilling mud reaches surface from MD of 11848.3. After that, 401.7 ft of 14 ppg spacer is pumped followed by 5750 ft (length) of 14.5 ppg cement lead. The TOC of cement lead showed by this section is 12250 ft indicating 250 ft above previous casing shoe (13 5/8” at depth 12500 ft) from the depth of 18000 ft. The 16.4 ppg cement tail is pumped after cement lead. The TOC is found to be at 18000 ft which means 5500 ft below previous casing shoe.

Other information provided by this section is the amount of lead and tail cement required. As shown by the last column, 1326 sacks of lead cement and 467 sacks of tail cement are predicted.

After we set all the data in Job Data, we are ready to see the plot of pressure profile, where we can see the ECD interference with the fracture gradient. The following pressure profile was obtained from the OptiCem software using the combination of all previous input data:

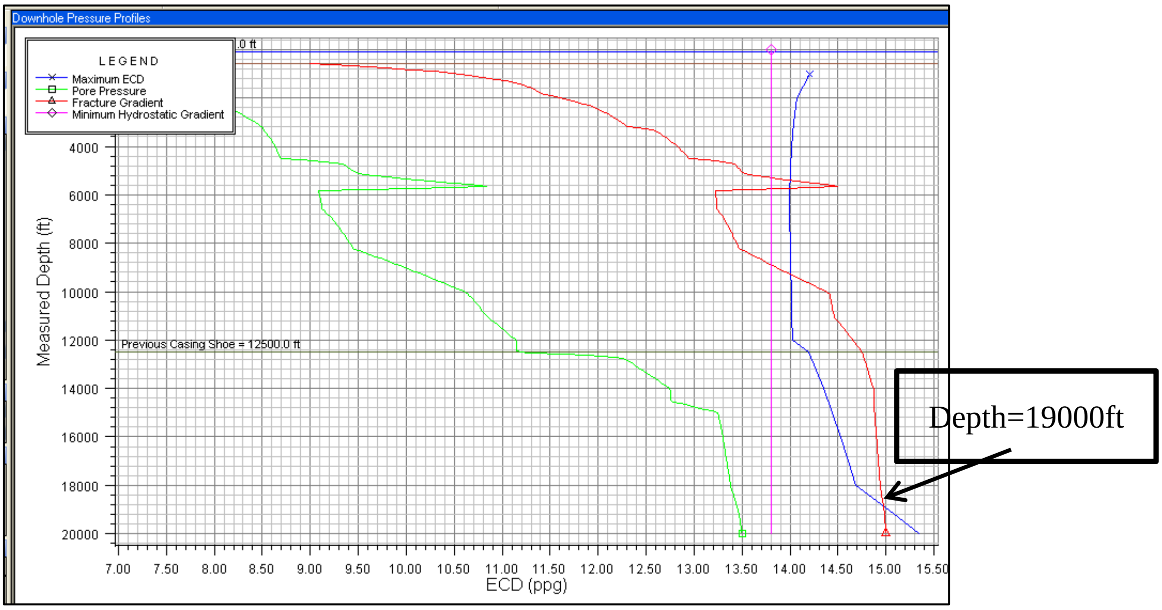


Figure 15 : Downhole pressure profile 1st trial

From the plot we can see clearly that the blue line which presents ECD is exceeding the fracture gradient on the bottom of the hole at depth 19000ft. Thus during pumping the cement this indication could lead to a fracture of formation and further drilling problems like loss of circulation.

Now we can simulate the data to fulfill the ECD requirements, such as:

- **Decreasing flowrate**
- **Decreasing the lead cement height**
- **Decrease the lead cement weight to suitable levels**
- **Decrease the spacer weight to suitable levels**

We can highly play around with one or two data and reach the desired results, but in this case, only flowrate will be the manipulating data. The decrease of the flowrate will leads to an ECD getting smaller and that is the outcome we would like to see.

The following is the modified Job Data:

Job Data

Automatic Rate Adjustment Safety Factor 0.00 psi Fluid Editor Inner String Used Edit

Use Foam Schedule Disable Auto-Displacement Calculation Annulus Injection

	Type	Fluid	New Stage?	Stage No	Placement Method	Rate (bbl/min)	**Stroke Rate (spm)	Duration (min)	Volume (bbl)	**Strokes	Top of Fluid (Measured Depth) (ft)	Length (ft)	Bulk Cement (94lb sacks)
1	Drilling Fld (Muc	13.8 ppg obm, 13.80 ppg	☑	1	Volume	10.00	200.00	0.00	0.00	0.0	0.0	11848.3	
2	Spacer/Flush	14.0 ppg spacer, 14.00 pp	☑	2	Volume	10.00	200.00	5.00	50.00	1000.0	11848.3	401.7	
3	Cement	14.5 ppg lead, 14.50 ppg	☑	3	Top of Fluid	10.00	200.00	32.12	321.19	6423.8	12250.0	5750.0	1325.99
4	Cement	16.4 ppg tail, 16.40 ppg	☑	4	Top of Fluid	10.00	200.00	11.72	117.22	2344.5	18000.0	2000.0	466.78
5	Cement	16.4 ppg tail, 16.40 ppg	☑	5	Shutdown			5.00					
6	Top Plug*		☑										
7	Spacer/Flush	14.0 ppg spacer, 14.00 pp	☑	6	Volume	10.00	200.00	1.00	10.00	200.0	19778.7	141.3	
8	Mud	13.8 ppg obm, 13.80 ppg	☑	7	Volume	10	160.00	90.40	723.17	14463.3	0.0	19778.7	
9			☐										

Figure 16 : Job data for normal practice cement 2nd trial

The rate has been change from 17 bbl/min to 10 bbl/min and the result is as below:

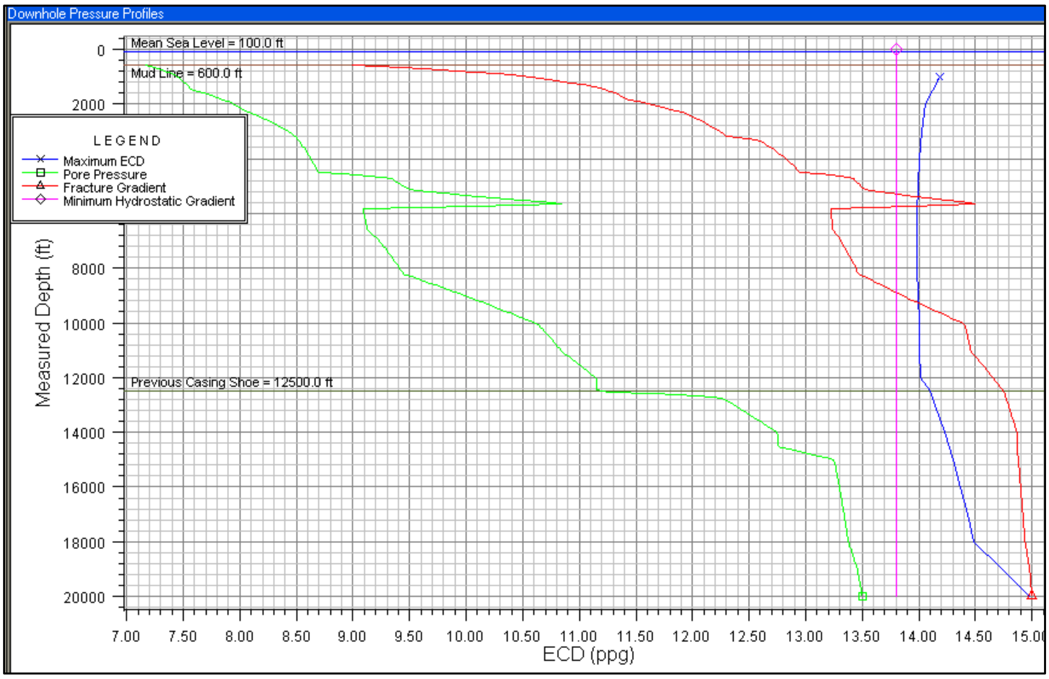
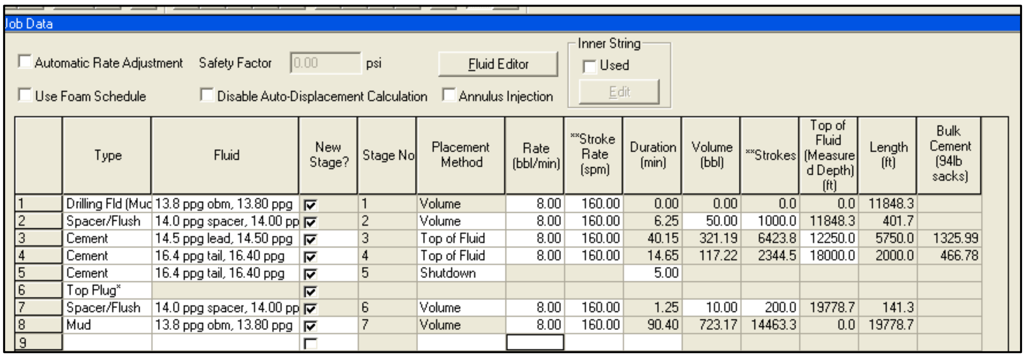


Figure 17 : Downhole pressure profile 2nd trial

This time we can see that ECD is not exceeding the fracture gradient and we can perform the cementing job with the latest data and procedures with no taking a risk to fracture the formation that can lead to well problems.

HOWEVER, since the ECD line at depth 20000ft is right on top of the fracture line, a little bit more decrease in pumping rate will give a better result and smaller ECD.

The rate is then change from 10bbl/min to 8bbl/min and the result is as below:


Job Data

Automatic Rate Adjustment Safety Factor 0.00 psi Fluid Editor Inner String Used Edit

Use Foam Schedule Disable Auto-Displacement Calculation Annulus Injection

	Type	Fluid	New Stage?	Stage No	Placement Method	Rate (bbl/min)	**Stroke Rate (spm)	Duration (min)	Volume (bbl)	**Strokes	Top of Fluid (Measured Depth) (ft)	Length (ft)	Bulk Cement (94lb sacks)
1	Drilling Fld (Muc	13.8 ppg obm, 13.80 ppg	☑	1	Volume	8.00	160.00	0.00	0.00	0.0	0.0	11848.3	
2	Spacer/Flush	14.0 ppg spacer, 14.00 pp	☑	2	Volume	8.00	160.00	6.25	50.00	1000.0	11848.3	401.7	
3	Cement	14.5 ppg lead, 14.50 ppg	☑	3	Top of Fluid	8.00	160.00	40.15	321.19	6423.8	12250.0	5750.0	1325.99
4	Cement	16.4 ppg tail, 16.40 ppg	☑	4	Top of Fluid	8.00	160.00	14.65	117.22	2344.5	18000.0	2000.0	466.78
5	Cement	16.4 ppg tail, 16.40 ppg	☑	5	Shutdown			5.00					
6	Top Plug*		☑										
7	Spacer/Flush	14.0 ppg spacer, 14.00 pp	☑	6	Volume	8.00	160.00	1.25	10.00	200.0	19778.7	141.3	
8	Mud	13.8 ppg obm, 13.80 ppg	☑	7	Volume	8.00	160.00	90.40	723.17	14463.3	0.0	19778.7	
9			☐										

Figure 18 : Job data for normal practice cement 3rd trial

And the ECD result is as below:

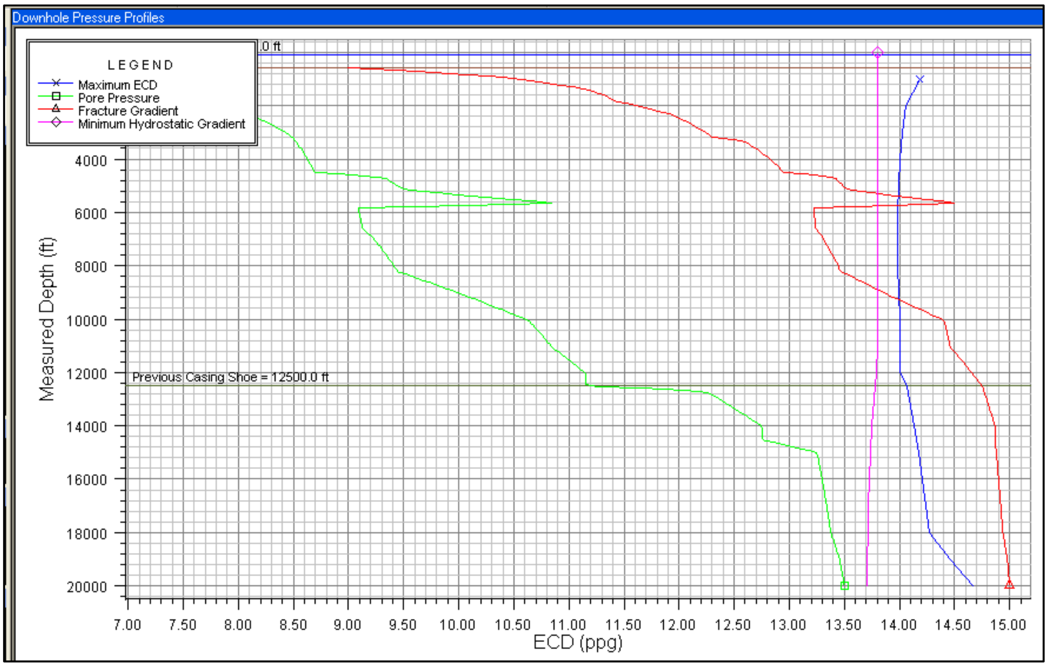


Figure 19 : Downhole pressure profile 3rd trial

From the picture above,the ECD is decreasing and its moving away from fracture line. This result shows a better ECD line if compare to the other two results

Therefore,the best pump rate can be used for the cementing operation for this kind of well is 8bbl/min. it also shows that the cement data used is the best and optimum.

The next figure represents the fluid positions frame after the animation of how the fluid moves inside casing and out to annulus and their final respective positions after the cement reaches its designated positions:

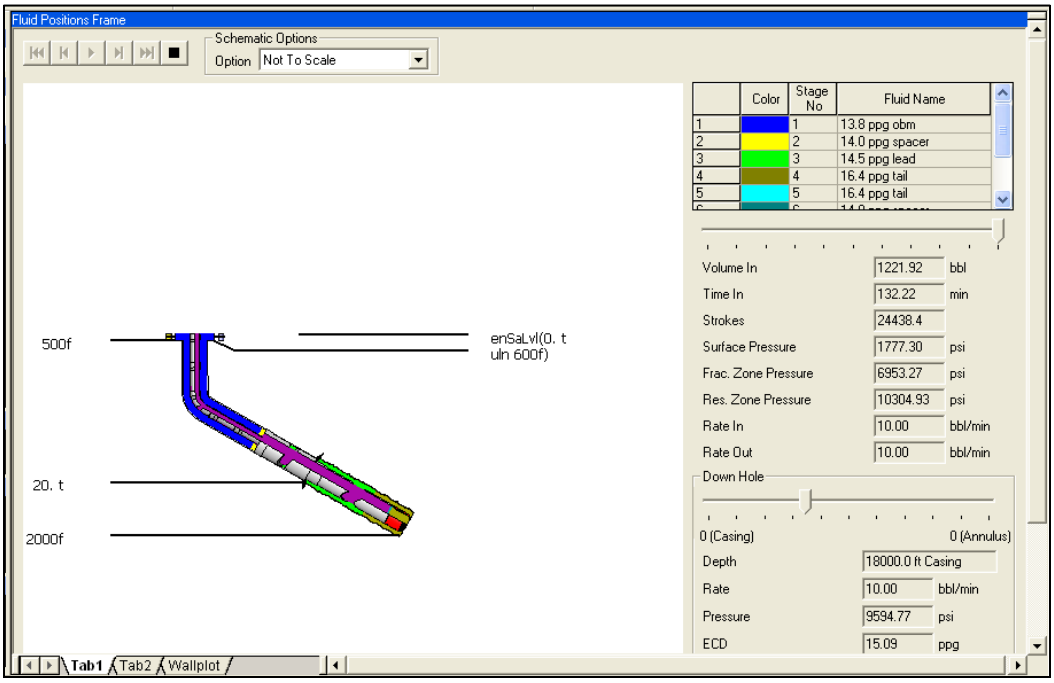


Figure 20 : Fluid animation for 3rd trial of normal practice cement

This animation shows the whole condition of the hole after the cement be set at the target area. The blue line indicating the drilling fluid used,followed by spacer,lead and tail.

The effect of Silica fume in cementing design.

In this part, 15 % of silica fume is used in the cement. Several data that has been found from experiment is been used in the analysis.

The main data that must need to be changed in the software is at JOB DATA section. The fluid used this time has different rheology properties

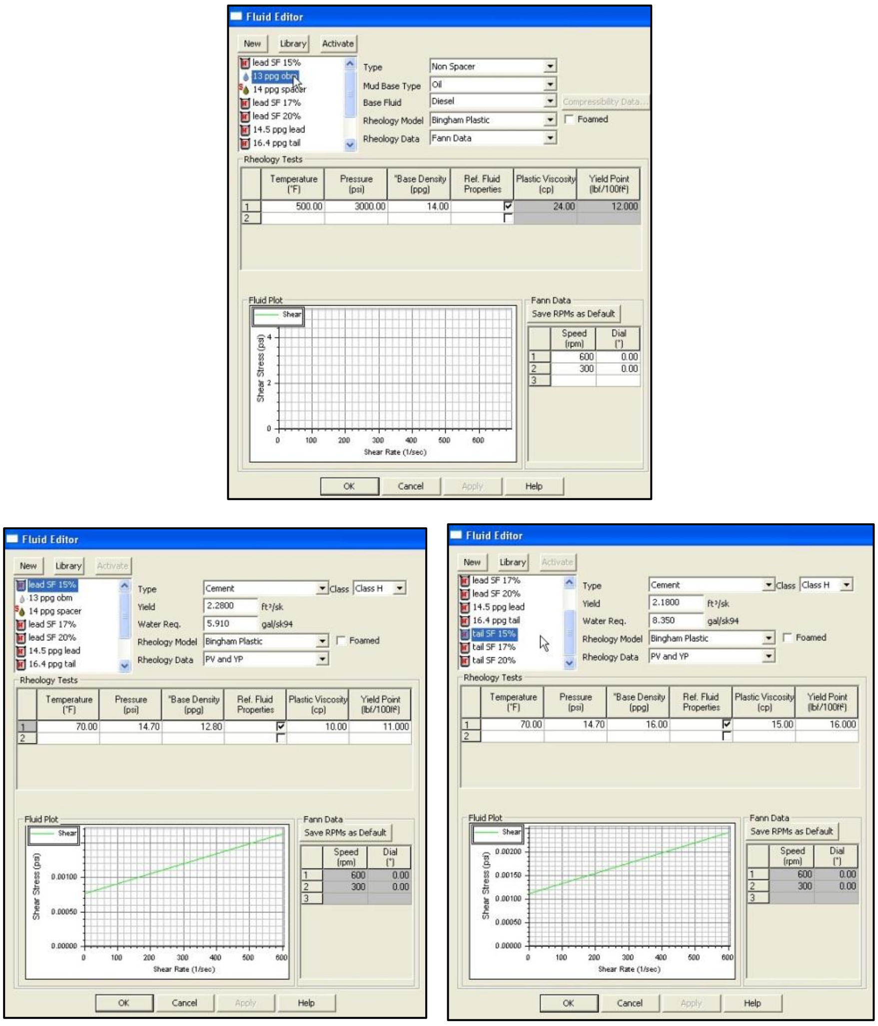
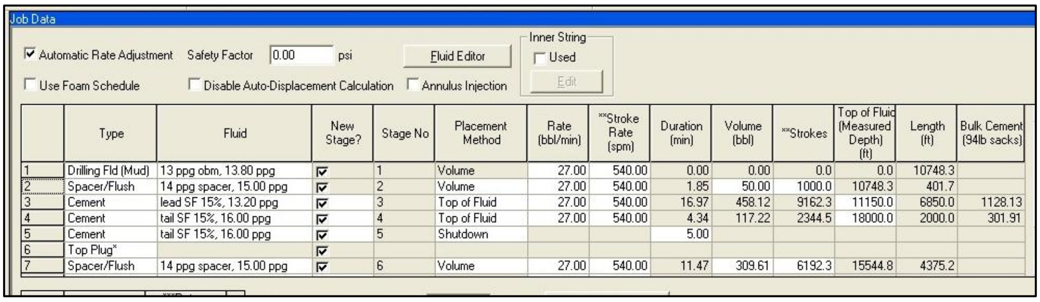


Figure 21 : Fluid data for cement with 15% SF

As all the data is defined in this fluid editor, we can proceed with the job data section.


Job Data

Automatic Rate Adjustment Safety Factor 0.00 psi Fluid Editor Inner String Used Edit

Use Foam Schedule Disable Auto-Displacement Calculation Annulus Injection

	Type	Fluid	New Stage?	Stage No	Placement Method	Rate (bbl/min)	**Stroke Rate (spm)	Duration (min)	Volume (bbl)	**Strokes	Top of Fluid (Measured Depth) (ft)	Length (ft)	Bulk Cement (94lb sacks)
1	Drilling Fld (Mud)	13 ppg obm, 13.80 ppg	☑	1	Volume	27.00	540.00	0.00	0.00	0.0	0.0	10748.3	
2	Spacer/Flush	14 ppg spacer, 15.00 ppg	☑	2	Volume	27.00	540.00	1.85	50.00	1000.0	10748.3	401.7	
3	Cement	lead SF 15%, 13.20 ppg	☑	3	Top of Fluid	27.00	540.00	16.97	458.12	9162.3	11150.0	6850.0	1128.13
4	Cement	tail SF 15%, 16.00 ppg	☑	4	Top of Fluid	27.00	540.00	4.34	117.22	2344.5	18000.0	2000.0	301.91
5	Cement	tail SF 15%, 16.00 ppg	☑	5	Shutdown			5.00					
6	Top Plug*		☑										
7	Spacer/Flush	14 ppg spacer, 15.00 ppg	☑	6	Volume	27.00	540.00	11.47	309.61	6192.3	15544.8	4375.2	

Figure 22 : Job data for cement with 15% SF 1st trial

The flowrate for all the fluids is initially set to be at 27 bbl/min.13.8 ppg drilling mud reaches surface from MD of 10748.3 ft. After that, 401.7 ft of 15 ppg spacer is pumped followed by 6850 ft (length) of 13.2 ppg cement lead. The TOC of cement lead showed by this section is 11150 ft indicating 1350 ft above previous casing shoe (13 5/8" at depth 12500 ft) from the depth of 18000 ft. The 16 ppg cement tail is pumped after cement lead. The TOC is found to be at 18000 ft which means 5500 ft below previous casing shoe.

Other information provided by this section is the amount of lead and tail cement required. As shown by the last column, 1129 sacks of lead cement and 302 sacks of tail cement are predicted.

After we set all the data in Job Data, we are ready to see the plot of pressure profile, where we can see the ECD interference with the fracture gradient. The following pressure profile was obtained from the OptiCem software using the combination of all previous input data:

Figure 23 : Down hole pressure profile for !5% SF 1st trial

The blue line representing maximum ECD is found to exceed the fracture gradient on tht bottom of the hole at depth 17500 ft. this will lead to formation damage and next will lead to loss of circulation.

Therefore, some modifications need to be implemented in order to make the ECD line to be within the range. This time, several parameters has been changed in order to see the effect of them.

The modifications to the data made:

- **The spacer weight was decreased from 15 ppg to 14 ppg**
- **The Lead Cement height was decreased from 6850 ft to 5750 ft**
- **Lead Cement weight was decreased from 13.2 ppg to 12.8 ppg**
- **The flowrate was decreased from 27 bbl/min to 10 bbl/min**

Job Data

☑ Automatic Rate Adjustment Safety Factor 0.00 psi Fluid Editor Inner String ☐ Used

☐ Use Foam Schedule ☐ Disable Auto-Displacement Calculation ☐ Annulus Injection Edit

	Type	Fluid	New Stage?	Stage No	Placement Method	Rate (bbl/min)	**Stroke Rate (spm)	Duration (min)	Volume (bbl)	**Strokes	Top of Fluid (Measured Depth) (ft)	Length (ft)	Bulk Cement (94lb sacks)
1	Drilling Fld (Mud)	13 ppg obm, 13.80 ppg	☑	1	Volume	10.00	200.00	0.00	0.00	0.0	0.0	11848.3	
2	Spacer/Flush	14 ppg spacer, 14.00 ppg	☑	2	Volume	10.00	200.00	5.00	50.00	1000.0	11848.3	401.7	
3	Cement	lead SF 15%, 12.80 ppg	☑	3	Top of Fluid	10.00	200.00	32.12	321.19	6423.8	12250.0	5750.0	790.94
4	Cement	tail SF 15%, 16.00 ppg	☑	4	Top of Fluid	10.00	200.00	11.72	117.22	2344.5	18000.0	2000.0	301.91
5	Cement	tail SF 15%, 16.00 ppg	☑	5	Shutdown			5.00					
6	Top Plug*		☑										
7	Spacer/Flush	14 ppg spacer, 14.00 ppg	☑	6	Volume	10.00	200.00	30.96	309.61	6192.3	15544.8	4375.2	

Figure 24 : job data for cement with 15% SF 2nd trial

As shown,the number of cements required also changed. It requires 791 sacks of lead cement and 302 sacks of tail cement which are lesser amount than the one without silica fume.

The downhole pressure profile is viewed again as below:

Figure 25 : Down hole pressure profile for 15% SF 2nd trial

The result shown is positive and all the design parameters are the best and optimum.

Here are the summary of the cement design data which is the best and optimum for both cement type,with silica fume and without silica fume.

Analysed Data for SF 0%

Cement	**Plastic Viscosity,CP**	**Yield Point, Lbf/100 ft^2**	**Yield, ft^3/sk**	**Water Req. , gal/sk94**	**Based Density, PPG**	**Flowrate, gpm**
Tail	178.3	19.810	1.41	8.35	16.4	8
Lead	39	9.23	1.38	5.910	14.5	8

Table 2 : Analysed data for cement without silica fume

Analysed Data for SF 15%

Cement	**Plastic Viscosity,CP**	**Yield Point, Lbf/100 ft^2**	**Yield, ft^3/sk**	**Water Req. , gal/sk94**	**Based Density, PPG**	**Flowrate, gpm**
Tail	15	16	2.18	8.35	16	10
Lead	10	7	2.28	5.910	12.8	10

Table 3 : Analysed data for cement with 15% silica fume

This is the the best data for the cementing design for both cement with SF and without SF. Clearly, the cement with silica fume plastic viscosity is way lesser than the one without silica fume. It is good to have lesser viscosity to make thing easy in pumping the cement. The flowrate of cement with silica fume shows 10 gpm which is faster than without silica fume. It can help us to reduce the time and cost.

From this simulation also has shown the best data to perform cement with silica fume safely. In fact,all the benefit from using Silica fume can now be achieved.

5.0 CONCLUSION

Cementing of a HPHT well is an essential part of completion and it influences the future production from the well. Designing proper cement program which is compatible with formation conditions are the key to a successful cement job. Throughout the research papers that have been discussed, it shows HPHT well condition is really complex and a lot of factors need to be considered especially the ECD. However, all of the complexities must be put aside. Number of HPHT well is now really increasing in many areas of the world. Acceptable production from HPHT well needs successful drilling and completion operation. Since cementing is one of the drilling and completion activites, It is really important to have a perfect design which is optimum and efficient.

Through the first step in preparing this paper which is reviewing literature review as much as possible, it is found really helpful to get better understanding on the condition in HPHT well. HPHT well is really complex to be cemented. It needs a suitable drilling program in order to be safe in term of cost and life. Through this paper, it has successfully proven that landmark software is a very reliable software to be used in order to resolved all this complexities found in HPHT well condition.

This paper is focusing on some parameters that can be tuned to have a safe cementing job. HPHT wells has a very narrow and small pore-frac window which makes us difficult to pump any fluid in the hole. The term ECD or Equivalent circulating density is the density that must be looked carefully, and controlled to be in between this pore-frac window when fluid pumping operation is done. Once cement is pumped in the hole, the ECD must not exceed the fracture gradient line and must not be below than pore pressure gradient line. If it found out to be exceed the fracture line ,it means the formation underground will fractured and this will definitely lead to a loss of circulation. On the other side,if it is found to be below pore pressure, kick might happen. This will then lead to a blowout which can cause damage to all facilities and the biggest loss is the loss of human's life.

The initial results from the OptiCem module of the Landmark software shows us that the higher flowrates lead to a big value of ECD which can eventually break the formation by exceeding the fracture gradients. The following modifications could be made in order to decrease the ECD of the pumped cement during circulation:

- **Decreasing flowrate (ensure there will be no free fall)**
- **Decreasing the lead cement height (suitable levels)**
- **Decrease the lead cement weight to suitable levels**
- **Decrease tail cement height and weight (if suitable)**
- **Decrease the spacer weight to suitable levels**

In this project, flowrate is the easiest parameters to be played around. As can be seen from the result for cement without any Silifa Fume added, the flowrate was changed from 17 bbl/min to 10 bbl/min and lastly it is found that 8 bbl/min is the best flowrate which give a safe circulation condition. However in second case,which silica fume is added, this paper proved the effect of tuning more parameters such as cement tail and lead density and height as well.

This paper has come out with two sets of data which are for cement without silica fume and cement with 15% silica fume. These data are the optimized data that can be used safely in cementing operation.

Since there is a set of optimized data for silica fume, this paper also suggested that silica fume should be practiced in cementing operation nowadays. It has a lot of advantages as been mention in the discussion part and all of these advantages can be achieved by the assistance of Landmark software.

This paper has met its objectives which is to optimize the slurry design by controlling their respective ECD.

6.0 REFERENCES

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