CHAPTER 1:

INTRODUCTION

1.1 ERD well cementing

Directional drilling is the ability to steer the drill-stem and bit to a desired bottom hole location and has been in use for the last half century. Prior to that time the only option was to drill wells vertically. Directional wells are initially drilled straight down to a predetermined depth and then gradually curved at one or more different points to penetrate one or more given target reservoirs.

Directional drilling is usually accomplished with the use of a fluid-driven downhole motor, which turns the drill bit. Extended-Reach Drilling (ERD) is essentially an advanced form of directional drilling. ERD employs both directional and horizontal drilling techniques and has the ability to achieve horizontal well departures and total vertical depth-to-horizontal distance ratios well beyond conventional directional drilling. More sophisticated steerable drilling equipment is utilized, along with continuous realtime monitoring of conditions in the wellbore. Greater care must also be taken to ensure the wellbore remains clean, via careful selection of drilling mud characteristics and flowrates and rotation of the drill string during drilling. Long ERD wells have been characterized as wells with greater than eight (8) kilometers of horizontal displacement.

ERD has many benefits, such as preventing water and gas coning, achieving inaccessible reservoirs, increasing production, etc. Acceptable production from ERD well needs successful drilling and completion operation. Hence, cementing of an ERD 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 is one of the most significant factors for a successful cement job. There are many challenges faced before performing cement program, during implementing it and after the cement is set such as water and mud channeling.

1.2 Problem statement

There is a possibility of the formation of mud channels in lower part of annulus and formation of free water channel on the upper part of the drain hole which can lead to a cementing as well as overall well drilling, completion and production problems.

1.2.1 Problem Identification

Problems encountered during ERD well cementing are similar to those on any cement job, but are aggravated by factors such as:

- **wellbore orientation**
- **geometry**
- **gravitational forces**

Wellbore geometry is affected by drill string contact on the low side of the hole which can lead:

- **to an oblong shaped wellbore and thus, incorrect hole volume calculations for the cement**

Gravitational forces affect:

- **centralization problems of the casing**
- **progress solids settling from the wellbore fluids**

Deposition of solids in the wellbore is one of the most severe problems in ERD wells. Settling of barite or drill cuttings causes the mud on the low side of the annulus to have a higher density than the mud on the top side. Even though smaller particles may remain in suspension, larger particles may not, and in horizontal systems they:

- **accumulate in the narrowest part of the annulus which is the bottom part**
- **further diminishes the capability of the mud or/and cement slurry to remove a solids from the well walls**

Solid settling is not limited to the drilling mud, but also occurs in the cement slurries if proper precautions are not observed.

Proper slurry design is of extreme importance, not only to prevent particle settling, but also to help cover appropriate rheologies for efficient placement and mud removal, as well as providing the help in providing top-side integrity in the annulus.

1.2.2 Significance of project

The success of any cementing job either in ERD or conventional well necessitates that all annular spaces be filled with cement and the creation of a good bond at the cement/formation and cement/casing interfaces. As a consequence, the slurry has to displace all the drilling mud that originally occupied the annular space. Therefore, mud removal is a very critical step in the cementing process as well as preventing the water channeling along the upper part of the annulus after the cement settles in an preplanned region of the borehole.

Mud has no strength and is therefore easily flocculated by formation fluids. If all the mud is not removed, stringers of mud that can easily be converted into channels are formed along the pipe or borehole. Therefore, a lot of emphasis is placed in completely replacing to column of drilling mud with cement. Channels lead to migration of well fluids which can result:

- **in major economic losses**
- **hydrocarbons' migration from high pressure zones to other zones**
- **stimulation treatment cannot be confined to any one specific zone**
- **casing can be attacked by corrosive waters due to the production of unwanted fluids**
- **loss of treating chemicals to unwanted zones when acidizing or fracturing will occur if a zone is not isolated by a proper cement sheath**

The water channeling also leads to a corrosion attack for a casing, which is highly undesirable. Water channels occur not only as pure water, but the contaminated mixture with the cement, which highly affects the properties of the cement slurry and lead to a different behaviors and results such as wrong thickening time, reduced compressive strength. All these can affect the provision of a good zonal isolation and proper cementing of the ERD well section, which eventually could have a great impact in terms of overall economy and well integrity.

1.3 Objectives and scope of study

1.3.1 Objectives

1) To design the cement program that would prevent mud channeling on lower side of ERD well annulus using Landmark software
2) To design the cement program that will prevent free water channels on upper side of the ERD well hole drain based on the literature review

1.3.2 Scope of Study

The research will involve the understanding of ERD well cementing. The study in this project contains two main parts:

1. To design the accurate cement program for the ERD well using Landmark software

2. To obtain the most suitable cement slurry by focusing on preventing problems with mud and water channeling

1.3.3 Relevancy of the Study

This project will focus on the topic of cementing the ERD wells. As the present drilling operations increasingly move towards developing the field of petroleum engineering, the technology allows us to drill the ERD wells and implement new methods, standards and problem solutions. If recently few kilometers of horizontal displacement in well trajectory was considered as ERD, this year's outstanding achievement on 28 January, 2011 when the world's longest borehole was drilled at the Odoptu field, Sakhalin-I with a measured total depth of 12,345 meters (40,502 ft) and a horizontal displacement of 11,475 meters (37,648 ft) shows that new technologies emerge that claims to be pushing the existing boundaries of ERD.

1.3.4 Feasibility of the project within the scope and time frame

The project started with literature reviews involving reading text books papers in order to have better understanding on the topic of ERD wells and its cementing principles. The initial self-learning also covers various cases and problem inspecting on the same topic. On duration of project research, I attended the Landmark software training classes and obtained the certificate from the Halliburton on successful completion of the courses. Definitely I received an important knowledge and skills in utilizing and implementing the software in order to fulfill the objectives of my project. The further work includes designing the cement program using the software by inputting the real field data and simulating the cementing job by analyzing the outcomes and making appropriate conclusions. Further training was done using Excel Macros (VBA) which I learned from my superior colleagues and online trainings. By writing a suitable coding, I created a data to assist me in my objectives fulfillment. Later on proper analysis, comparisons, conclusions and further recommendations were done and project directed towards the final step of completion within a time frame given by Universiti Teknologi Petronas.

CHAPTER 2:

LITERATURE REVIEW

There are number of research papers have been done in the past years in field of enhancing the cementing of the conventional, directional as well as horizontal and ERD wells. Fifteen of them were reviewed and studied by me, which are as follows:

Title of paper/research/work	Authors	Date
1. Problems in Cementing Horizontal Wells	Sabins, Fred L., Halliburton Services	April, 1990
2. Method for improving cement placement in horizontal wells	Jennings Jr., Alfred R. (Plano, TX)	06/14/1994
3. New Cement Formulation Helps Solve Deep Cementing Problems	Brothers, L.E., deBlanc, F.X., Halliburton Services	June, 1989
4. Successful Deep Liner Cementing in South Texas	Rae, P., Roemer, R., Kirksey, J., Dowell Schlumberger	27th February-2nd March,1990
5. Mud and Cement for horizontal wells	C. Zurao and C. Georges, Elf Aquitaine	October 5-8, 1986
6. A Novel Cement Slurry Design Applicable to Horizontal Well Conditions	Reza Salehi, and Abouzar Mirzaei Paiaman,(NISOC)	August 8, 2009
7. Field evaluation of Key Liner Cementing Variables on Cement Bonding	S.T. Saleh (Colorado School of Mines) and J.P. Pavlich (Westport Technology Center)	23-25 March, 1994
8. Zonal Isolation and evaluation for Cemented Horizontal Liners	Huawen Gai, T.D. Summers, *SPE*, D.A. Cocking, and Chris Greaves, *SPE*	December, 1996
9. Techniques for Successful Liner Cementing in the Anadarko Basin	R.E. Muncrief, El Paso Exploration Co.; R.E. LaFollette, Halliburton Services; and C.G. Rainbolt, NL Baroid/NL Industries Inc.	April 1-3, 1984

10. A Laboratory Investigation of Cementing Horizontal Wells	Wilson, M.A., Halliburton Services; Sabins, F.L., Halliburton Services	September, 1988
11. Drilling and Cementing Extended Reach Boreholes	Arthur H. Hale, Houston; Kenneth M. Cowan, Sugar Land, both of Tex.	October 22, 1992
12. Deviated-Wellbore Cementing: Part 1 – Problems	S.R. Keller, Exxon Production Research Co.; R.J. Crook, Halliburton Services Research Center; R.C. Haut, Exxon Production Research Co.;	August 1987
13. Deviated Wellbore Cementing: Part 2 - Solutions	Crook, R.J., Halliburton Services; Keller, S.R., Exxon Production Research Co.; Wilson, M.A., Halliburton Services Center	August 1987
14. Factors Contributing to Cement Sheath Deposition in Casing under Highly Deviated Well Conditions	: Sabins, F.L., Halliburton Services; Smith, R.C., Amoco; Broussard, M.D., Amoco Norway Oil Co.; Talbot, K.J., Amoco; Olaussen, S.R.,	December, 1993
15. Displacements in Eccentric Annuli during Primary Cementing in Deviated Wells	Jakobsen, J., Sterri, N., Saasen, A., Aas, B., Rogaland Research; Kjosnes, I., Vigen, A., Statoil A/S	April 7-9, 1991

Table 1. List of studied and analyzed papers

The followings are my short summaries and personal analysis of the studied papers and works related to cementing operations problems mainly:

1)

Title : **Problems in Cementing Horizontal Wells**

Authors : **Sabins, Fred L., Halliburton Services**

Date: **April, 1990**

The main slogan for the research was *"Any casing eccentricity becomes critical in horizontal wells because of its effect on flow velocity distributions in the wellbore"*. From this we can surely predict that the focus of the paper will be the effect of decentralization of the casings on proper cementing job.

In horizontal wells, an increased possibility of a narrow casing-to-wellbore clearance on one side exists because of pipe eccentricity combined with gravitational forces. Inadequate clearance on the narrow side of these wellbores can lead to uncemented portions of casing circumference because of the excessive forces needed to move any material (solids or gelled

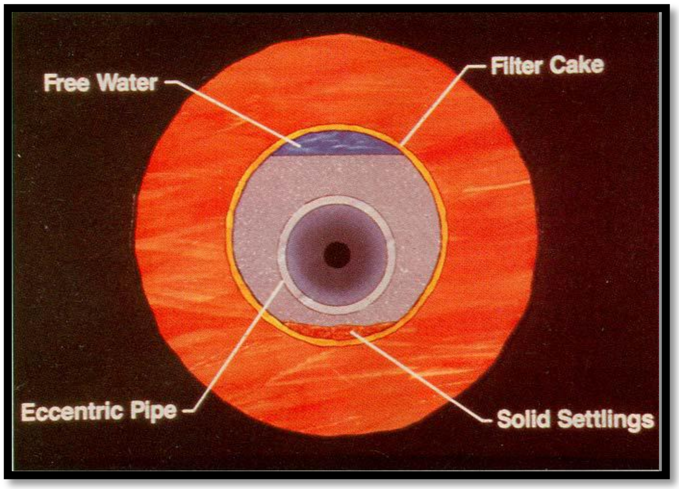


Figure 1.Schematic problems during cementing

drilling fluids) in this area. Any casing eccentricity becomes critical in horizontal wells because of its effect on flow velocity distributions in the wellbore.

Decentralized casing compounds the problem of displacement because cement slurry and spacers tend to follow the path of least resistance and bypass the path of least resistance and bypass the narrower side (bottom) of the annulus. Therefore, using the casing equipment necessary to provide maximum centralization is essential.

2)

Title: **Method for improving cement placement in horizontal wells**
Authors: **Jennings Jr., Alfred R. (Plano, TX)**
Publication Date: **06/14/1994**

Often a failure of the cementing operation occurs in horizontal wellbores because the density of the cement does not allow sufficient displacement of drilling mud and other residue from the tubing/wellbore annulus, thereby resulting in channeling of cement and improper tubing or pipe/formation bonding. Therefore, the purpose of this work was to find a method for improving the effectiveness of the cementing operation in deviated or horizontal wellbores which allows the removal of void spaces in the horizontal section due to incomplete displacement of wellbore materials and the effects of gravity on high density cement.

The given research was directed to a well completion process for improved cement placement in a horizontal wellbore located in a formation having productive and non-productive intervals. In the practice of this invention, a cleaning fluid is circulated down the wellbore in an amount and for a time sufficient to condition and clean the wellbore for cementing a production tubing or casing in place. Afterwards, production tubing having centralizers there around is placed into the wellbore so as to locate the tubing centrally within the wellbore. Next, a cement "spacer" fluid is directed down an annular space formed between the tubing and the wellbore so as to substantially clean-out this space in order to provide better bonding. Later, first cement is directed down the annular space or annulus and up the tubing which cement has a density greater than the cement spacer fluid and is in an amount sufficient to fill the annulus. Subsequently, second cement is directed down the annulus and up the tubing. This cement has a density less than the density of the first cement which causes it to override the first cement thereby filling any voids along the horizontal section which were unfilled by the first cement so as effectively isolate the casing from the formation.

3)

Title: **New Cement Formulation Helps Solve Deep Cementing Problems**
Authors: **Brothers, L.E., deBlanc, F.X., Halliburton Services**
Date: **June, 1989**

In this research paper the authors were concerning about the cementing of deep wells in the Fandango field in south Texas, that has typically required many hours of laboratory time and complicated field mixing procedures to produce successful results. Heavyweight (18.5- to 19.5-ppg) salt-saturated cement slurries previously used in this field have been difficult to mix and pump continuously because of high viscosity imparted by the high concentrations of cement additives required in salt-saturated cement. High additive levels have been necessary to produce desirable cement slurry properties because of

(1) Extreme temperatures encountered in south Texas deep-well cementing

(2) Interference with chemical interaction between cement and additives caused by high salt concentrations, as the high salt concentrations tend to decrease the effectiveness of most common cement additives-e.g. , retarders, fluid-loss additives, and dispersants.

At high temperatures, concentrations of these additives can become unacceptably large, while the additives themselves are not as effective under these conditions. The main goal of the research efforts has been to develop a cementing system that is easier to mix and pump than these traditional materials, which have been pushed to their effective limits by extreme operating conditions. Laboratory work has centered on engineering a *polymer* with the temperature stability necessary for use as a cement additive under bottomhole conditions of 400F [204C] and higher and in the presence of high salt concentrations. As a result of these efforts, a polymer that imparts several desirable cement slurry properties to improve cementing results under high-temperature, saturated-salt conditions was developed. A single synthetic-polymer additive provides cement retardation, fluid-loss control, and dispersant properties with normal design considerations as opposed to the lengthy design requirements of other cement systems. A particular benefit derived from use of the new cement system involves cementing of long liners.

4)

Title: **Successful Deep Liner Cementing in South Texas**

Authors: **Rae, P., Roemer, R., Kirksey, J., Dowell Schlumberger**

Date: **27 February-2 March 1990**

Purpose: **Presentation for IADC/SPE Drilling Conference held Houston, Texas**

In parts of South Texas, the cementing of long drilling and production liners has long been one of the most challenging aspects of well completion. High formation pressures require mud and cement weights that approach the equivalent fracture gradient of the exposed open hole interval. Very low pump rates and excessively long job times have been common due to the constraints imposed by tight annular clearances and the use of heavy, viscous cement slurries. Another problem associated with these wells is the temperature gradient in this area. Geothermal gradients of 2 deg.F /100 ft. create large temperature differentials from liner top to bottom, even with liners of only moderate length. Consequently, developing TOL compressive strength and adequate seal at the liner lap has been difficult with the cement retarder concentrations necessary for bottom hole conditions.

The main focuses of the presentation was to resolve those problems by introducing new techniques and tips for improvement of cementing jobs. The first and most obvious of them was to redesign the cement slurry. The reason was that the high surface viscosities of the slurries have the tendency to settle downhole and is unacceptable for the successful cementing job. Also the slow compressive strength development at TOL (top of liner) problem is present in salt saturated cement systems. The problem persuaded the authors to use a fresh water based cement system using a non-viscosifying, liquid-loss control additive. The settling of weighting agent was resolved by using zero free water dispersant in liquid form. Gas migration was also one of the issues on that area which was resolved by simply using the high concentration of a liquid latex anti-gas migration additive in place of the fluid-loss control additive.

Weighted spacer fluids are always pumped in the wells. The role of the spacer is to provide compatibility between mud and cement and this is particularly important in the case of oil-base mud. In addition due to the authors, the spacer must change the wettability of the pipe and borehole surfaces to a water-wet condition to facilitate cement bonding.

Accurate prediction of bottom hole temperature during the cementing operation is always difficult. Considering the great importance of this single parameter on the success of the job, the most practical way was found by the authors. The small thermally sensitive probe is circulated in drilling mud to the TD and back. It measures the maximum well temperature at the time of circulation to within 5 degrees F. The last aid for improvement of the cementing job quality was the using of computer placement simulators. Numerous simulations are run after examining the well to identify the most favorable placement technique, pump rates, surface pressures and etc.

5)

Title: **Mud and Cement for horizontal wells**

Authors: **C. Zurao and C. Georges, Elf Aquitaine, and M. Martin, *Inst. Francais du Petrole.***

Date: **October 5-8, 1986**

Purpose: **Presentation at the 61st Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in New Orleans, LA**

High angle and horizontal wellbores raise many questions concerning the characteristics of mud and cement. This paper is a summary on author's knowledge and works about two subjects. I will mainly focus the issues concerning cementing jobs.

Cementing horizontal casing strings were a fairly new practice at the time the paper was present. However a good casing/formation cement bond is certainly the best means of obtaining correct well productivity. A successful horizontal cement job should prevent the formation of mud, water and gas channels and of a free water channel on the upper part of the drain hole.

The principle issues in the paper concerning cementing were:

- **The reliability of cementing outfits**
- **The appearance and accumulation of free water along the upper part of the well bore**
- **The best placement methods**

The test concerning the first one was made using 300 m long test bench in a 7" casing. The standard liner cementing wiper plugs were circulated more than 900 m in water and pressure test was performed at 725 psi. No leakage was observed. However, use of a float shoe or float collar seemed unconvincing. Thus the safer valve which is spring loaded valves (flapper) was decided to be used better.

The development of slurries without free water was extremely important as its presence in horizontal situations result in the formation of a water drain along the upper part of the annulus. During the tests, this phenomenon showed not only the accumulation of water on the upper part of the bore, but also migration of this water along the bore towards the high points of the annulus (inclination was 88 to 92 degrees). Thus a slurry with 0.2% free water in a 7”/10” annulus would result in water drain of from 2 mm to more than 1 cm. Few proposals were made for improvement of this case:

- **To enhance the rapid hydration and fast crystallization by the addition of certain dispersants, this causes support structure between the grains of cement. If possible, $CaCl_2$ is also added to create the same type of support structure and thus preventing sedimentation.**
- **Addition of solid inert microelements which due to their very small size (10 to 100 times smaller than a grain of cement) and large number (5 to 25% of cement total weight) would occupy the gaps between the grains of cement and would greatly increase pressure loss in the event of interstitial water migration.**

A test bench with variable annular distance allowed the authors not only to study the problems of centralization but also the displacement of interfaces between mud, spacer and slurry. In the case of turbulent displacement of all three fluids, excellent hole cleaning was observed. On the other hand, slow displacement showed the very great influence of the density unbalance parameter between the fluids. As soon as this unbalance becomes large, during the displacement in the casing and annulus results in heavier fluid passing below the lighter fluid. This phenomenon can cause the pollution of the cement by the mud. That is why longer spacer design is preferred. Knowing the all information above the turbulent flow enables us with good cementing quality avoiding trapping at restrictions or between shoe and well bottom. At the same time, the formulation of slurries without free water is more difficult. Unfortunately because of the challenges in horizontal drilling, the most often used regime will be slow type flow in order to avoid the risks of fracturing and losses during cementing.

6)

Title: **A NOVEL CEMENT SLURRY DESIGN APPLICABLE TO HORIZONTAL WELL CONDITIONS**

Authors: **Reza Salehi, and Abouzar Mirzaei Paiaman,** ***National Iranian South Oil Company (NISOC)***

Date: **August 8, 2009**

Horizontal wellbores raise many questions concerning the characteristics of cement. A successful horizontal cement job should prevent the formation of mud, water and gas channels. Free water channel forms on the upper side of the drain hole. Therefore, the following cement placement parameters should be studied to overcome the cementation problems: casing hole eccentricity, drilling fluid rheological behavior, hole geometry, spacer design (rheology), density, cement slurry design. The study on this paper focuses on cement slurry design in horizontal wells.

Cement slurry properties must be controlled particularly in highly deviated and horizontal wells. Free water is the most important factor that should be as low as possible after cement sets. The other properties that are important are: yield point, plastic viscosity, fluid loss, gel strength, and the dynamic settling characteristics of cement slurry.

To design a cement slurry formulation, several factors should be considered, including well depth, temperature, mud-column pressure, viscosity and water content of cement slurries, pumping, or thickening, time, compressive strength, quality of available mixing water, compatibility with drilling fluid and spacers, density, lost circulation and filtration control.

There are number of problems associated with cementing the deviated or horizontal wells. The curvature may interfere with centralization or running of casing. Gravitational forces affect centralization problems and progress solids settling from the wellbore fluids. Deposition of the solids in the wellbore is one of the most severe problems in horizontal wells. Settling of barite or drill cuttings causes the mud on the low side of the annulus to have a higher density than the mud on the top side. Even though smaller particles may remain in suspension, the larger once will accumulate in the narrowest part of the annulus. This further decreases the ability of the mud to remove them from the annulus.

That issue can cause the poor cementing jobs running. Cement slurries that have free water and/or settling tendencies can result in water channels on the top side of a horizontal annulus, or an area of reduced compressive strength cement which may not provide the annular seal required for zonal isolation during stimulation treatments. It is necessary that well-suspended, zero free water slurries be used in horizontal cementing applications. Spacer systems must be compatible with the drilling fluid in order to prevent forming a highly viscous interface which may promote mud channeling, must have flow properties conducive to the removal and suspension of settled solids, and be stable for extended periods of time at wellbore temperatures.
Here are some suggestions by authors:

- **Free fluid may show up not as clear water, but as a thin portion of cement-colored fluid containing well dispersed cement fines. This type of slurry should be rejected or adjusted to eliminate this phenomenon because the less dense portion at the top may not provide the strength required for a proper seal, and may provide a path for well fluid movement.**
- **This could also leave the casing exposed to corrosion from down hole water contact.**
- **To prevent solid settling, cement yield point should exceed 15 lb/100 ft^2.**
- **Cementing long horizontal intervals often requires cement slurry with a low yield point to reduce friction pressure while pumping, in an effort to avoid exceeding the equivalent circulation density of the well**.

Cement additives have played an important role in the advancement of cementing technology. To properly use the available cements, additives were developed to control the major cement properties, i.e., thickening time, consistency, fluid-loss rate, free water, setting time, etc. Here are some additives mentioned by the authors required to change the property of the cement while needed:
Fluid loss additives are now available for any degree of salinity desired and for any wide temperature ranges. Fume silica or special heavyweight materials have proven beneficial in providing slurry stability for horizontal applications. It is now possible to design heavy

weight slurries with reasonable flow properties and still maintain the weighting material in suspension. Fume silica and improved surfactants have increased the design capabilities for low density and/or foamed cement slurries where these have application. Non-lignin, non-cellulose retarder chemicals have been developed to provide more predictable slurry response and improved control over thickening time.

Note by authors: *all the additives that are using together should be compatible with each other otherwise, cement slurry become so viscous and it will not be pumpable.*

7)

Title: **Field evaluation of Key Liner Cementing Variables on Cement Bonding**

Authors: **S.T. Saleh (Colorado School of Mines) and J.P. Pavlich (Westport Technology Center)**

Date: **23-25 March, 1994**

Purpose: **Presentation at the Western regional Meeting held in Long Beach, California, USA.**

This paper presents field evaluation results of several key variables which affect liner cementing performance in deviated and horizontal wells. The investigated variables are: displacement flowrate, cement slurry rheology, turbulators placement, and back pressure. These variables were identified based on several years of database development and analysis in the Prudhoe Bay field in Alaska. The development of successful liner cementing practices has increased liner cementing success to 90% based on well log evaluation and production history.

According to authors the following changes in liner cementing practices were introduced, field tested and reviewed in this paper:

- Increased displacement rate ➔ annular velocity increased from 350 to 530 ft/min (8-12 BPM in 8.5" – 7" liner annulus, and 5-8 BPM in the 6.75" – 5.5" liner annulus)
- Apply back pressure (250-350 psi) for around 3 hours as soon as cement is placed and 10 stands of drill pipe are pulled out of hole to avoid gas migrating and forcing good cement bond

- Limit hole cleaning and mud conditioning period to 2 hours if possible
- Open hole and liner lap centralization by turbulators*
- Cement displacement was carried out without liner rotation and at times without reciprocation because of the effective flow regime of turbulators' swirl is achieved by choosing the right cement rheology design and high flowrate of cement displacement.

*Note: ***Information about turbulators***

Turbulators will:

- Maintain centralization creating a positive stand off
- Increase the cleaning action of mud-wash pumped ahead of cement
- Force jelled mud out of the hole
- Reduce the torque needed to turn rotating liners and pipe
- Reduce the chance of cementing stringers up the hole by displacing a full column of mud and thus preventing costly squeeze and fishing jobs
- Put cement slurry in a spiral turbulence around the pipe to insure a uniform bond for fifteen to twenty feet above each turbulator

Figure 2. Turbulator

8)

Title: **Zonal Isolation and evaluation for Cemented Horizontal Liners**
Authors: **Huawen Gai, T.D. Summers, *SPE*, D.A. Cocking, and Chris Greaves, *SPE*, *BP Exploration.***
Date: **December, 1996**
Purpose: **SPE International Meeting on Petroleum Engineering held in Beijing.**

This paper discusses the novel application of technology on the cementing and bond evaluation from the world-record breaking at that time ERD wells in Wytch farm, where horizontal liners of the order of 800 to 1300 m, at TVD of approximately 1600 m have been successfully cemented and perforated. Important aspects of zonal isolation, such as the use of spiral-blade centralizers, rotating the liner, and trials of the external casing packer (ECP), are discussed in detail.

The most challenging issues for cementing ERD wells at Wytch Farm included followings:

- **Cleaning the hole properly and running the liner to total depth**
- **Design the cement slurry and spacer rheologies to minimize the ECD, yet be able to provide a good quality flow displacement**
- **The cement slurry must have zero free water and particle settlement so that a high side channel cannot develop after cement placement**
- **Centralize the liner as much as possible to ensure the mud removal on the narrow side of the annulus**

One of the main problems of the Wytch Farm field is that it has low reservoir pressure, which makes us pay a serious attention on ECD while circulating and cementing the liner. Because of this issue the 7” liner could not be cemented in the 8.5” hole of the reservoir section without fracturing the formation at reasonable flow rates. It was decided that 5.5” liners cemented in 8.5” hole would be the best option.

Pipe rotation and reciprocation are commonly accepted methods for liner cementing in conventional horizontal and ERD wells. It is believed that rotation would help break up the gelled mud on the narrow side of the annulus where the mud is difficult to remove because here the velocity profile of the annulus reaches the minimum point, and reciprocation would provide extra fluids velocity and pressure surges to help break up the gelled mud in washouts in addition to the movement of the centralizers. But in Wytch Farm ERD only liner rotation was recommended while cementing, because:

- **The formation fracture gradient is low, and the pressure surges by pipe reciprocating can cause the breaking down of formation can lead to a cement losses**
- **The drag created in high-angle well will not make possible the pipe reciprocation easily**

- **Due to the current technology of the liner hanger it is safer to set and release the pipe from it before cementing jobs starts, thus reciprocation is impossible**

Pipe centralization is one of the most crucial parameters in the cementing program. However, the effects of various functions of centralizers and the optimal selection of them are apparently not well understood. Due to the authors of the paper there were some debates as whether the spiral would help create more turbulence and thus better mud removal or would lead to the contamination between the mud, the spacer and the cement. Anyway for the Wytch farm wells two solid spiral-blade centralizers per casing joint were run and the use of them showed the benefice of the choice. The 1 or 2 meters of the intervals behind the centralizers have a better bond than the adjacent regions, because of the local turbulence creation. The CBL (cement bond logging) showed that those intervals were so good cemented and were almost free from microannulus.

9)

Title: **Techniques for Successful Liner Cementing in the Anadarko Basin**

Authors: **R.E. Muncrief, *El Paso Exploration Co.;* R.E. LaFollette, *Halliburton Services;* and C.G. Rainbolt, NL *Baroid/NL Industries Inc.***

Date: **April 1-3, 1984**

Purpose: **SPE Deep Drilling and Production Symposium held in Amarillo, Texas, USA.**

Due to the nature of wells drilled in the Anadarko Basin, as with any area where abnormally high formation pressures are encountered, it has been noted that poor primary cementing jobs can often plague a well throughout its productive life. This paper deals with procedures which can be followed that should assist in planning and performing the job. The running and cementing of deep liners is an area of great concern when designing and drilling wells within the boundaries of the Anadarko Basin.

When designing the particular cement to use in cementing the liner, several factors are to be considered. The cement should be designed to meet the specific down hole conditions such as bottom-hole circulating temperature, bottom-hole pressures, drilling fluid properties, hole and casing size, and pump time needed to safely place the cement. These down hole conditions constitute the need for certain additives to control slurry weight, strength, rheology, pump time, and other desired properties needed to obtain an acceptable cement job.

Table 2. Common Cement Additives for Anadarko Basin Liner Cements

Constituent	**Function**	**Concentration rate**
Silica flour	Coarse or fine, used to stabilize strength and decrease permeability at higher temperatures, often greater than 230 deg F	20-40%
Potassium chloride or sodium chloride	Protects water sensitive shales and clays	5-18%
Retarders	Increase pump time of cement for desired placement time	0.1-2.5%
Friction reducers and dispersants	Reduces apparent viscosity of slurry which allows turbulent flow at lower rates	0.5-1.5%
Weighting materials	Increase slurry weights(hematite, barite, sand)	4-125#/sk
Anti-foamers	Minimizes air entrainment which decreases foaming problems	0.1-0.25%
Fluid loss	Minimizes loss of waters to porous zones	0.4-2.5%

The volume of cement to be used is normally calculated from a caliper measurement which is run in conjunction with the open-hole electric logs. It has been found that the observed volume with a 20% excess factor, along with the capacity of the liner lap with a 300-400 ft. cap on top of the liner has produced the best results.

A weighted spacer is normally run between the mud and the cement. The primary purpose of a spacer is to help prevent mud contamination within the cement. Contaminated cement will yield a lower compressive strength and may also become viscous enough to create an excessive amount of friction pressure, thus increasing the possibility of breaking down the formations. Since this paper deals only with water-based mud systems, only water-based spacers will be discussed. Water-based spacer systems are generally comprised of weighting materials, silica flour, gel, and dispersant. Fresh water cannot be run as a spacer due to the extreme sensitivity of the shale sections as well as the clays within the sand formations. A brine system spacer following the mud could cause severe mud flocculation and hamper the mud displacement efficiency. It has been seen that spacer volumes should be in the range of 30-50 bbls or a volume great enough to provide a contact time of 6-8 minutes. Spacer densities are normally higher than the density of the mud, but less than that the cement.

Pipe movement has a huge advantage in cementing jobs. While the authors agree with liner rotation which allows the removal of solids in narrow side of the well, the pipe reciprocation is not preferred, so as it can lead to an easily stuck of drillstring.

Figure in the right shows how the drillstring rotation during hole cleaning prior to cementing operations and during cementing can aid in mud removal.

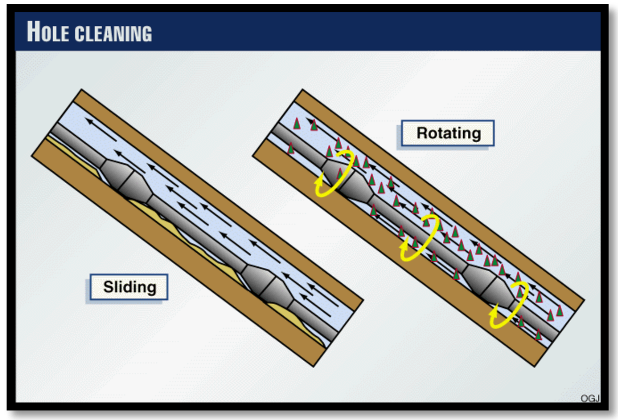


Figure 3. Hole cleaning by sliding and rotating

10)

Title: **A Laboratory Investigation of Cementing Horizontal Wells**

Authors: **Wilson, M.A., Halliburton Services; Sabins, F.L., Halliburton Services**

Date: **September, 1988**

Obtaining a successful cement job will remain one of the most important factors to the productive life of any well and will be especially critical for horizontal-well completions. Achieving high mud-displacement efficiency under highly deviated or horizontal-well conditions requires that special attention be given to the many aspects of drilling and completion practices.

The study in this paper focuses on factors affecting mud-displacement efficiency focused on cementing an ultralow-permeability formation that is being evaluated as a subject for horizontal completion. Factors evaluated for this study included influence of hole and pipe sizes, pipe centralization, displacement rates, and spacer systems. The major area of investigation has been the development of drilling-fluid systems that would possess solids-transport characteristics such that compacted channels of these materials on the low side of the annulus could be minimized or eliminated. This research has shown that control of the rheological properties of the mud is critical in achieving the channel-free annulus required for a successful primary cement job. The research described here was initiated because of a growing interest in horizontal completions through the chalk formations of the North Sea area. These low-permeability chalk zones require stimulation to yield maximum production. The drilling fluid that was used in this research was low-toxicity oil based mud, because in those regions, cuttings' cleaning is of high environmental importance. Most operators use the same type of drilling fluid system, because of the bore stability and drilling lubricity created by their use. One of the researches before showed that the water fluid system causes hole instability and pore collapse in that region.

The laboratory test held by the authors has the configuration as next **FIG:**

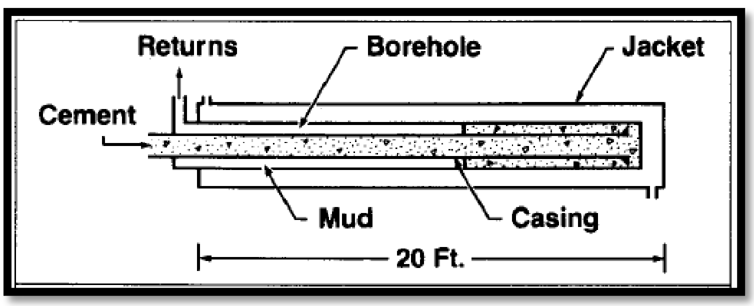
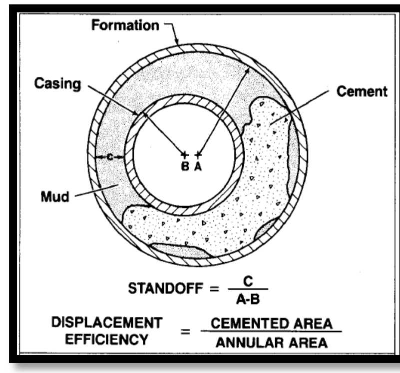


Figure 4. Configuration of laboratory investigation

The testing procedure entailed simulation of the entire life of the horizontal well from the initial drilling until the casing was cemented into place. The testing sequence involved the following steps:

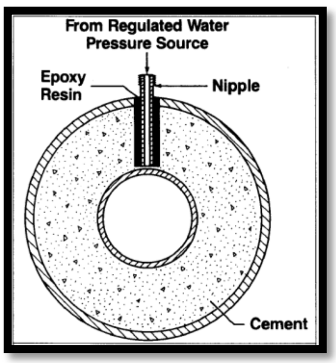
1. *Circulate the drilling fluid at the BHCT of 140 deg F for 1 hour at 3 bbl/min*
2. *Cease mud circulation for 24 hours while the model temperature increases to the 160 deg F BHST*
3. *Reinitiate drilling-fluid circulation for 1 hour at 3 bbl/min under BHST*
4. *Pump the desired volume and type of spacer at the rate to be studied*
5. *Circulate the designed 30 bbl of cement slurry at rate chosen*
6. *Pump the top wiper plug until it is seated on the pin in the bottom of the casing, and allow the cement to cure for at least 24 hours under BHST*

7. Cut the model into nine sections. Measure displacement efficiency and actual casing standoff for each section. Also, measure the hydraulic bond of casing to cement at the best possible location along the circumference of each region.



Next **FIG.** shows how the cut section looks like from the front view

The next procedure can be shown in next **FIG:**



After evaluating the displacement efficiency and standoff, the sections were then drilled so that the measurement of the casing-cement hydraulic bond could be conducted. Water was pumped to the interface at the best point of contact within each section, using a pressurizing system through an epoxy/nipple arrangement. The pressure required to bring that bond to failure was recorded as the hydraulic bond.

While talking about the mud system in this paper, two evidences can be indicated:

1) The most important criterion to be met is maintaining free-water content of the slurry as near zero as possible. This would decrease the creation of water channels on the top side of the annulus which happens due to heavier particles settlement.

2) The standard API procedure for measurement of free-water percentage is showing not accurate results. Under API procedure slurries show 1% free water, while testing under heated, deviated conditions shows 9% of free water content. So the new ways of testing and obtaining the free water percentage should be found out.

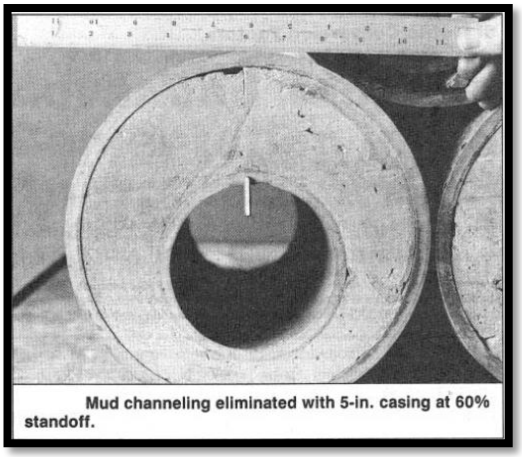


Figure 6. Mud channeling 5" casing

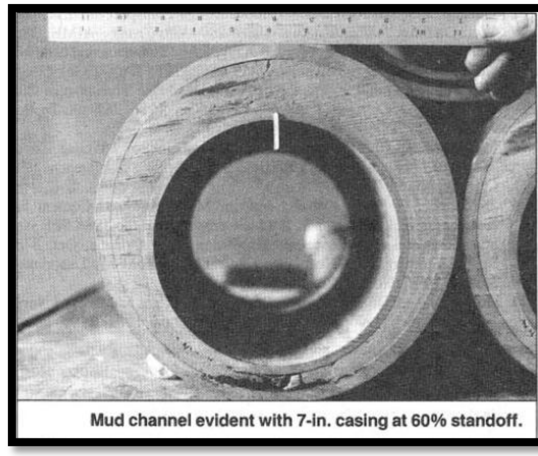


Figure 7. Mud channeling 7" casing

Looking at the picture above, we can discuss now about the impact of annulus size on good cement placement. In the first picture the 5" liner was used in 8.5" hole size, while in second picture we see the usage of 7" liner inside the same annulus. The narrow clearance in the low side of the annulus of 7" liner did not allow the circulation to remove the mud properly, which caused the channels. On the other hand the bigger clearance caused by using the 5" liner cementation enables us to avoid mud channels by applying less flow rate compared due case with narrower clearance.

Due to the tests held by authors of the 8 tests in which standoffs were below 60%. Seven tests showed low-side mud contamination. It appears that a minimum standoff of 60% throughout the horizontal section would be reasonable.

11)

Title: **Drilling and Cementing Extended Reach Boreholes**

Authors: **Arthur H. Hale, Houston; Kenneth M. Cowan, Sugar Land, both of Tex**

Date: **October 22, 1992**

According to authors the ERD wells are more expensive and challenging to drill because of the increased difficulty of carrying out the primary cementing operation. It is simply not possible in angled borehole to maintain the casing in the exact center of the borehole. This creates two problems. First, it is more difficult to remove the fluid on the side of the borehole where the annulus is narrower and second, it is more difficult to remove the filter cake on the side of the borehole wall where annulus is narrower. The latter problem is significant because the filter cake is generally incompatible with the cement. This can result in channeling of fluids used to wash out the drilling fluid and/or channeling of the cement leaving significant areas of unremoved and incompatible drilling fluid in the annulus. This case results in voids in the final cementing job.

During research in this paper it was discovered that by utilizing blast furnace slag* in the drilling fluid, a compatible filter cake is laid down on the borehole wall and thus, the filtercake on the side of the borehole where the annulus is narrow, turns into an asset rather than a liability. In addition undisplaced drilling fluid is converted into a strong, hard sealing material.

Note*

> ***Blast Furnace Slag*** *is formed when iron ore or iron pellets, coke and a flux (either limestone or dolomite) are melted together in a blast furnace. When the metallurgical smelting process is complete, the lime in the flux has been chemically combined with the aluminates and silicates of the ore and coke ash to form a non-metallic product called blast furnace slag.*

Conversion of drilling fluids (mud) into cements suitable for well cementing operations has been an area of interest within the petroleum industry for over fifty years. Improved zonal isolation in the annular space between a casing and borehole has been and continues to be the primary reason for pursuing this technology.

BS can be incorporated into a mud during the drilling process. After reaching the casing point, the casing string can be cemented by increasing the amount of BFS in the mud and adding other additives to control setting time. The additives in the BFS-mud mixture used for the cementing operation will cause any by-passed mud and the filter cake to set and form a reliable annular seal.

Solidification of a mud can be accomplished by the addition of between about **40** lb/bbl and **500** lb/bbl) of BFS to a water-base mud. This amount of slag generally produces a final BFS-mud mixture density between about 10 ppg and 20 ppg depending upon the density of the mud. Common mud additives control setting time and rheological properties.

Because of its low impact on mud properties, BFS may be added to a drilling fluid at low concentrations even during drilling operations. The filter cake resulting from a mud containing BFS can be set to form a primary seal at the formation face. In addition, any mud which is not displaced during the casing cementing operation can be set to provide an additional seal and structural support for the casing.

And as a conclusion from authors they underlined that BFS has widespread application as a material to improve zonal isolation in well cementing operations. This solidification technology provides a combination of fluid and solid properties with improved zonal isolation, broad applicability, and simplicity of design and application to bring mud solidification technology into widespread use.

12)

Titles: **Deviated-Wellbore Cementing: Part 1 – Problems**

Author: **S.R. Keller, Exxon Production Research Co.; R.J. Crook, Halliburton Services Research Center; R.C. Haut, Exxon Production Research Co.; D.S. Kulakofaky, Halliburton Services Research Center**

Date: **August, 1987**

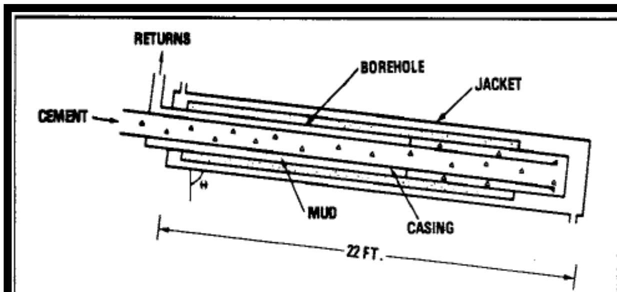
While a number of techniques for effective primary cementing are known, their application in a deviated well is often more difficult than in a vertical well. For example, it is generally more difficult to achieve good pipe centralization in a deviated well because the loads acting on the casing tend to force it toward the wellbore wall. These loads also tend to create high drag, torque, and bending stress that often limit pipe movement.

The purpose of the 1st paper is to demonstrate two problems that can significantly affect primary cementing in a deviated well:

1) Solids settling from the drilling fluid to the low side of the hole and

2) Free-water breakout from the cement slurry to the high side of the hole

While success or failure of a primary cement job depends on many factors, it is possible that in some of these wells, settled solids caused the mud on the low side of the hole to be difficult to displace. If the material on the low side of the hole is not displaced by the cement, a continuous mud channel will remain within the cement sheath. This reduces the integrity of the sheath. This reduces the integrity of the sheath and could lead to interzonal flow. According to various researches the hole cleaning becomes even harder in high-angled wells. The test done on 52^o well showed bad hole cleaning, compared to 28^o well cleaning where the hole was cleaned properly using the same mud system and procedures. The other evidence during the field works was observed, when the 7” liner could not be run into the 9 $^5/_8$” casing because of stuck deep in the well. Many attempts of circulation was done for hole cleaning. The liner was finally pulled out of hole and when engineers observed the liner hanger, it was heavily caked with barite and drilled solids which accumulated on the low side of the annulus.



Schematic of apparatus.

The figure shows the deviated apparatus used in simulating the cementing of a well. 16.8 ppg cement slurry was used in all tests. Mud used throughout the test was water based and the density was in two ranges: 11-13 ppg and 15-16 ppg.

Table 3. Fluid composition of mud and cement

FLUID COMPOSITIONS

Additives per 1 bbl for 16-lbm/gal mud	
Water, gal	29.80
Bentonite, lbm	15.00
Carboxymethyl cellulose, lbm	0.25
Barite, lbm	409.00
Lignosulfonate, lbm	4.00
Sodium hydroxide	
Additives per 1 bbl for 12-lbm/gal	
Water, gal	35.80
Bentonite, lbm	19.50
Barite, lbm	186.00
Lignite, lbm	1.00
Sodium hydroxide	
Additives per 1 sack for 16.8-lbm/gal cement	
Class H cement, lbm	94.00
Water, gal	3.91
Retarder, %	0.50
Dispersant, %	0.50

The test was done in the same way as the real procedures, except the usage of wiper plugs. They were excluded. The cement was given time to harden by creating 200 deg F on system. Samples of cement and mud were taken immediately after the displacement. 24 hours were given for cement hardening; later on the system was disassembled and cut into 10 parts. The next figure shows the 10 parts of the cut places of the system from side view. 1st segment is the closest to cementing head:

As we can see from the picture in all portions there is a presence of the mud channeling. When the channels were examined, it was found out that 98% of the content is barite which is settled from the drilling mud and

Segments from a mud displacement test conducted at 85° deviation angle. Arrows point to mud channel on low side of annulus.

Figure 7. Segments from a cut casing

was not properly displaced by the cement and spacer.

In addition to the mud channel at the bottom of the annulus, a water channel was often observed on the high side of the annulus and on the high side of the inner casing. The water channel was probably caused by free-water breakout from the cement slurry. The free water content of the cement slurry used in the test was more than 1.2% when measured with API test. However when measured with new API operating free-water test in which the slurry is heated to a more temperature, the free water was more than 9%.

---

13)

Title: **Deviated Wellbore Cementing: Part 2 – Solutions**

Author: **Crook, R.J., Halliburton Services; Keller, S.R., Exxon Production Research Co.; Wilson, M.A., Halliburton Services Center**

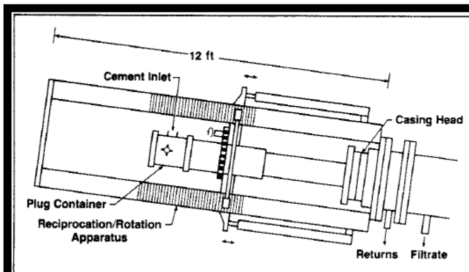
Date: **August, 1987**

In the second research paper the authors tried to identify the solutions to the problems they had found in the first part of the paper. The purposes of the study were to investigate further:

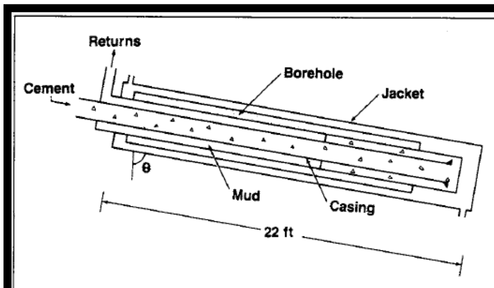
1) The relationship of drilling-mud yield point and the deposition of drilling mud solids

2) Methods known to improve drilling-mud displacement efficiency in vertical wellbores and to examine their effectiveness for deviated-well conditions

The apparatus used in conducting this research was the wellhead assembly used to circulate the various fluids under deviated conditions. A schematic of the stimulated well is shown in next figures as well:

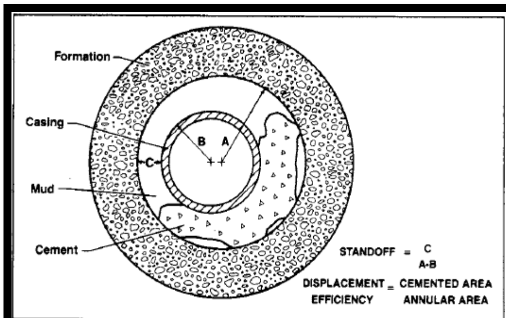


Schematic of reciprocation/rotation and wellhead assembly.



Schematic of simulated well and heating jacket.

The same procedures as usually done for cementing job was performed. The displacement started by circulating the drilling fluid for one hour and recording the amount of filtrate loss through the permeable formation. The formation was left static for 24 hours as it is done during logging jobs. After that period, the mud was circulated again once. The drilling mud then was displaced with a predetermined volume of spacer and cement slurry pumped at 4 bbl/min at the circulating temperature of 180 deg F. The volume of cement ranged from 10 to 30 bbl. After the cement was pumped in place, temperature was raised to 200 deg F and the cement was cured for 24 hours. The test sample was cut into sections to measure the average casing standoff and average mud-displacement efficiency:



Definition of casing standoff and displacement efficiency.

The average testing standoff was almost same for all sections as the casing top and bottom were centered.

A series of mud-yield point tests were conducted to determine the effect that the rheology of the drilling mud had on the displacement in an impermeable annulus when mud was displaced with only cement. Ten of these tests were conducted at an 85^o deviation. In the first seven tests, a continuous solids channel occurred along the bottom side of the annulus. However, when the mud yield point was high enough, the channel no longer appeared. This occurred on tests 8, 9 and 10 where yield point was more than 28 $lbf/100ft^2$. When the test was done on 60^o the results were on the same concept that by increasing the yield point, the channeling decreases but at lower values. These results have two main conclusions:

1) There appears to be threshold value of the mud yield point below which a continuous channel will occur

2) The yield point value required to prevent this channel from forming decreases with a decrease in deviation angle

The other tests were conducted to find out if the pipe centralizers help to improve the mud displacement efficiency. The result was positive and it showed that centralizers tend to increase the efficiency of mud removal even better if they are set in both ends of the pipes. The numbers of tests were also conducted to determine if the pipe rotation and reciprocation can improve the displacement of the mud. The results were positive again and showed significant improvement in high angle wellbore.

14)

Title: **Factors Contributing to Cement Sheath Deposition in Casing under Highly Deviated Well Conditions**

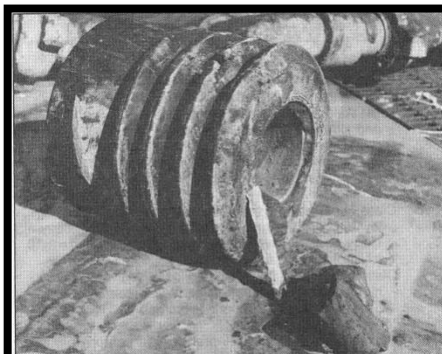
Authors: **Sabins, F.L., Halliburton Services; Smith, R.C., Amoco; Broussard, M.D., Amoco Norway Oil Co.; Talbot, K.J., Amoco; Olaussen, S.R., Halliburton Energy Services**

Date: **December, 1993**

Deposition of a cement sheath inside 9-5/8-in. intermediate casings cemented in highly deviated North Sea wells often required reaming before drilling operations could be resumed. Attempts to remove or prevent solids deposition by means of additional wiper plugs, flushes, or flow-rate variation were ineffective and led to a laboratory investigation of the factors contributing to the cement sheath formation in highly deviated wells. Authors have done laboratory tests in a large scale cement-displacement test facility.

As many tests and studies before were done with the assumption that the solid settlement occurs in the annulus, in this paper authors studied the phenomenon of solid settlement in the casing string, before the cement moves into the annulus. And the second point of focus was the assumption that the settlement occurs not from the drilling fluid, but from cement slurry itself.

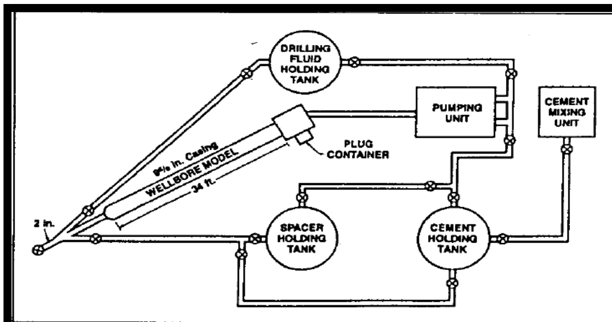
Number of wells in mid 80's was suspected to have a bad reaming tool, as they did not properly clean the well and were damaged.



-Damaged wipers on low side of top plug after displacing 34-ft channel of solids.

When operators used as many as 5 plugs to enhance the wiping inside the casing for many hours, the operation was unsuccessful. Thus they tried to change the properties of the cement, as they did not properly control the solid settlement at those times by increasing the yield point using additives. It seemed to show good results, when suddenly new cases started to show up. When the cement sheath cuttings were decided to be analyzed its properties showed the consistent of drilling fluid, cement and the spacer. Test decided to be conducted to get factors affecting the settlement.

Figure. 8 represent the apparatus used in the test:



Schematic of test facility layout.

The steps of the test were as followings:

1) Drilling fluid was displaced from model with 50 bbl of spacer at 10 bbl/min

2) Spacer was displaced with 760 bbl of cement at 10 bbl/min

3) The model was drained, the 2" connection at the discharge end was removed, and any solids settling was observed

4) The plug was pumped, solids were caught, and any solids left behind were noted

After number of tests by changing the mud type, cement yield point the following conclusions were done:

1) Cement slurry contributed most of the solids to the hard, immovable channel deposited inside the casing. Drilling fluid exhibited no dynamic settling and the spacer, when mixed properly showed very little settling.

2) When a solid channel in the casing of the model formed more than 1/16" channel, the plug did not remove it

3) The increased yield point in cement slurries tends to control the settling. And also the viscosity of prehydrated bentonite slurries increased with temperature, which seemed to be a positive factor in controlling settling

15)

Title: **Displacements in Eccentric Annuli during Primary Cementing in Deviated Wells**

Authors: **Jakobsen, J., Sterri, N., Saasen, A., Aas, B., Rogaland Research;**

Date: **April 7-9, 1991**

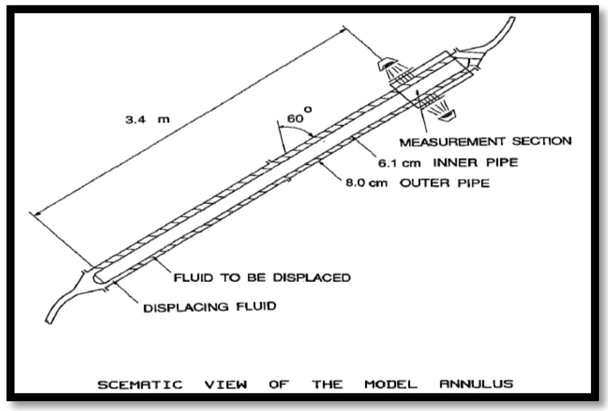
Purpose: **Prepared for presentation at the Production Operations Symposium held in Oklahoma City, Oklahoma**

This paper presents an experimental study of the displacement process in a 60^0 deviated laboratory well with a 55% eccentric annulus.

Primary cementing of an oil or gas-well requires a satisfactory displacement of drilling mud by spacer fluid and cement slurry. Several parameters, such as casing diameter relative to hole diameter, annulus eccentricity, rheology of mud and cement, flow rates affect the displacement efficiency.

During the test the model fluid viscosities and densities were selected such that the ratios between the viscous, gravitational and inertia forces were equivalent to similar ratios encountered in real situations.

The system used in the laboratory test has a diagram as in the *Figure. 9:* ⟶



Number of tests with laminar and turbulent flow, with different drilling fluid and cement rheology, as well as various cement-to-mud density ratios were used. The conclusion made after the test was that:

- **When the displaced fluid has less viscosity than displacing one, the displacement procedure shows better results than vice-versa (applicable only to laminar flow displacement)**

- **As the velocity increases, the flow in the wider part of the annulus becomes turbulent. When turbulence occurs, the axial frictional pressure drop increases. Therefore the flow rate at the narrow part of the annulus will also increase and a better displacement will be achieved**

- **When the displacing fluid was 5% heavier than the fluid to be displaced, the simulated mud flowed from the narrow part of the annulus up into the wider part of the annulus. This buoyancy-induced process strongly improved the displacement efficiency**

CHAPTER 3

THEORY AND METHODOLOGY

3.1 Research Methodology

The overall research methodology of this project is explained in the Project Flowchart below:

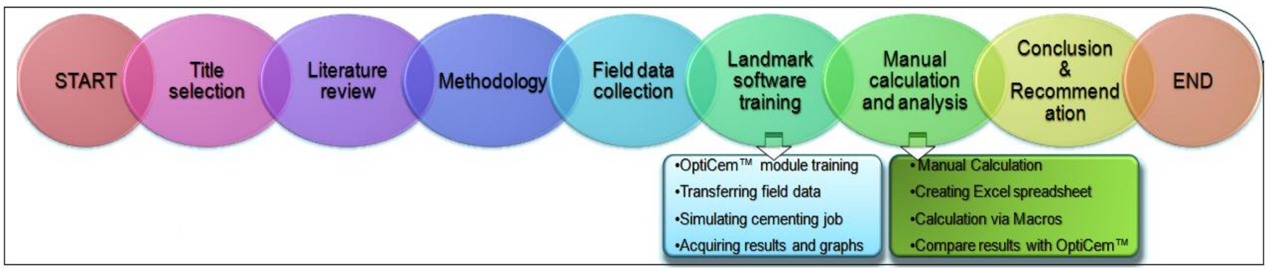


Figure 10. Project flowchart

3.2 Gantt Chart

A **Gantt chart** is a type of bar chart that illustrates a project schedule. Gantt charts illustrate the start and finish dates of the terminal elements and summary elements of a project. The following is the Gantt chart that was done by Microsoft Excel program for the course of Final Year Project 2:

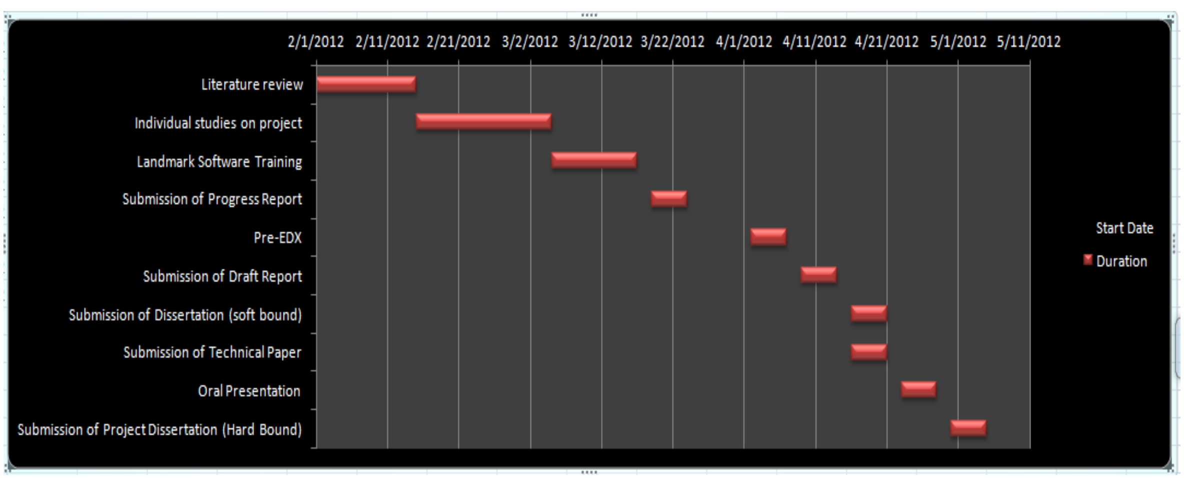


Figure 11. Gantt Chart

As can be clearly seen currently I am in the middle part which is Submission of Progress Report of the overall schedule for the second part (FYP2) of my project under the title: "**Designing a cement program for Extended Reach Drilling well using Landmark software"**

3.3 Project Work

The project semester started on second week by further recapping the literature review and making new find-outs and gathering more information of the topic. It was implemented by studying various cases, paper works and researches done before on ERD and horizontal well cementing, the problems occurred and solutions to it.

For my project I have two main objectives, which are:

1) To design the cement program that would prevent mud channeling on lower side of ERD well annulus using Landmark software

2) To design the cement program that will prevent free water channels on upper side of the ERD well hole drain based on the literature review

For the last two weeks the students of FYP who needed the skills of knowledge the Landmark software attended training session performed by Halliburton trainers.

3.4 Mud channeling problem

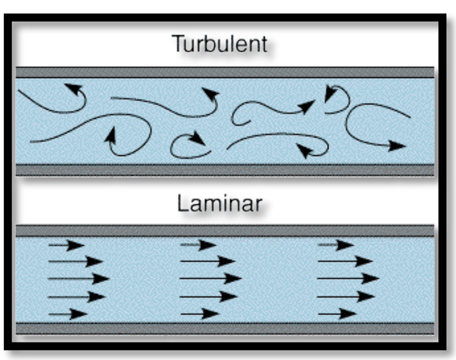


Figure 12. Flow regime of a fluid

The first part will be based on the literature review results and findings that I had analyzed. Most of the research papers claim that in order to overcome the mud channeling in the lower side of the inclined annulus as in ERD or horizontal wells, 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.

In order to have the right geometry and the casing setting depths we need to have a field data. The data that I will use in my project will be totally based from the real field data obtained from my Supervisor Reza Ettehadi Osgouei which is from the **Abu Field in Malaysia with the WELL: ABU-KECIL-2 (SLOT-2).**

First step is determining which class of the cement is suitable for us:

API Cement Classes

Class A:	For use from surface to 6000 ft (1830 m) depth*, when special properties are not required.
Class B:	For use from surface to 6000 ft (1830) depth, when conditions require moderate to high sulfate resistance.
Class C:	For use from surface to 6000 ft (1830 m) depth, when conditions require high early strength.
Class D:	For use from 6000 ft to 10,000 ft depth (1830 m to 3050 m), under conditions of high temperatures and pressures.
Class E:	For use from 10,000 ft to 14,000 ft depth (3050 m to 4270 m), under conditions of high temperature and pressures.
Class F:	For use from 10,000 ft to 16,000 ft depth (3050 m to 4880 m), under conditions of extremely high temperatures and pressures.
Class G:	Intended for use as a basic cement from surface to 8000 ft (2440 m) depth. Can be used with accelerators and retarders to cover a wide range of well depths and temperatures.
Class H:	A basic cement for use from surface to 8000 ft (2440 m) depth as manufactured. Can be used with accelerators and retarders to cover a wider range of well depths and temperatures.
Class J:	Intended for use as manufactured from 12,000 ft to 16,000 ft (3600 m to 4880 m) depth under conditions of extremely high temperatures and pressures. It can be used with accelerators and retarders to cover a range of well depths and temperatures.

Figure 13. API Cement Classes

Second step we do is to know the zone and the interval of the casing where we want to place the cement. Then we calculate the volume of the cement that that is required to cover that space. Formula to find out the **volume of cement** required in annulus:

$$\mathbf{V_c = H_c * C_{an}}$$

V_c = Volume of cement needed, bbl

H_c = Height of the cement that will occupy the annulus, ft

C_{an} = Annulus capacity, bbl/ft

Annulus capacity can be calculated by knowing the diameter of the hole:

$$C_{annc} = (D_{ann}^2 - OD_c^2) / 1029.4$$

C_{annc} = capacity of the annulus between the wellbore wall and casing

D_{ann}= open hole diameter; OD_c= outer diameter of the casing

The rat hole is extra hole drilled at the bottom of the hole that extends from the planned casing shoe until TD. That section also needs to be cemented and the volume will be needed for that is:

$$C_r = (D_{ann}) / 1029.4$$

D_{ann}= open hole diameter, in; C_r = rathole capacity, bbl/ft

Various companies have different policies on length of top of the cement from the casing shoe point inside the casing. Thus the volume capacity of the casing for that portion is:

$$C_c = (ID_c) / 1029.4$$

C_c = casing internal capacity, bbl/ft; ID_c = internal diameter of casing, in

At this point overall volume we need to pump can be calculated:

$$V_t = C_{annc} * H_{an} + C_r * L_r + C_c * L_!$$

Where:

V_t = total volume of cement to be pumped, bbl; H_{an} = Length of annulus portion to be cemented, ft

C_{annc} = capacity of the annulus between the wellbore wall and casing, bbl/ft

C_r = rathole capacity, bbl/ft; L_r = rathole length, ft; C_c = casing internal capacity, bbl/ft

$L_!$ = top of cement (from casing shoe), ft

It should be noted that **excess volume of cement which is 10%-15%** usually added by companies to the total volume of cement prior to cementing for safety and conservative reasons.

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.

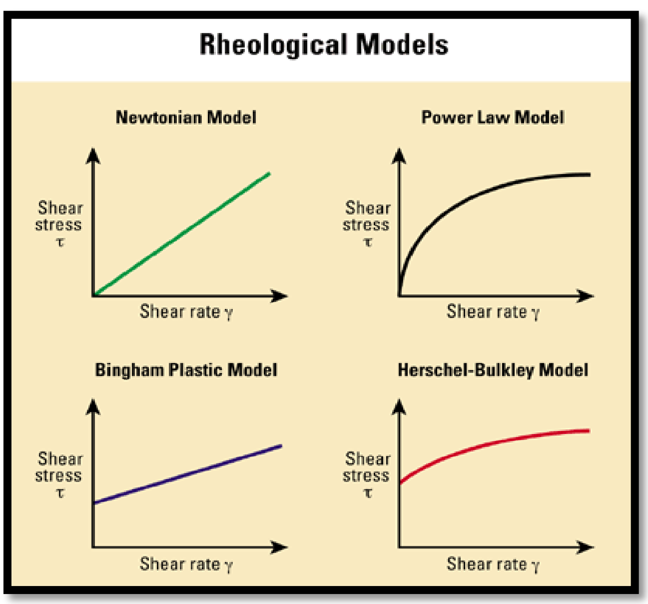


Figure 14. Rheological models of fluid

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 a 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.

3.4.1 Evaluation Criterion for Laminar or Turbulent Flow

Bingham Model for Flow in Annulus:

Bingham Plastic Fluid :

$$\tau = \tau_y + \mu_p \gamma \qquad \mu_p = 300\left(\frac{\theta_N}{N} - \frac{\tau_y}{N}\right)$$

For N=300 and 600 rpm:

$$\mu_p = \theta_{600} - \theta_{300} \qquad \tau_y = 2\theta_{300} - \theta_{600}$$

where μ_p is the plastic viscosity in cp, τ_y is the yield point in lbf/100 ft²

The equivalent Reynolds number in the casing or pipe is given by the following equation:

$$\boxed{N_{\mathrm{Re}} = \frac{928\,\rho\,\bar{v}\,D}{\bar{\mu}}}$$

Where, mean viscosity (cp) is:

$$\boxed{\bar{\mu} = \mu_p + \frac{6.66\,\tau_y\,D}{\bar{v}}}$$

And mean velocity (ft/sec) is:

$$\boxed{\mathbf{V=Q\ /\ (D^2*2.448)}}$$

Where, Q = flowrate, gpm; D = casing size, in

For the annulus region the equivalent Reynolds number is given as:

$$\boxed{N_{\mathrm{Re}} = \frac{757\,\rho\,\bar{v}\left(D_o - D_i\right)}{\bar{\mu}}}$$

Where mean viscosity (cp) is given as:

Mean viscosity term , for Bingham Plastics in annulus geometry

$$\bar{\mu} = \mu_p + \frac{5\left(D_o - D_i\right)\tau_y}{\bar{v}}$$

And the mean velocity (ft/sec) is given as:

$$V=Q/((D_1^{\,2}-D_2^{\,2})*2.448)$$

Where,

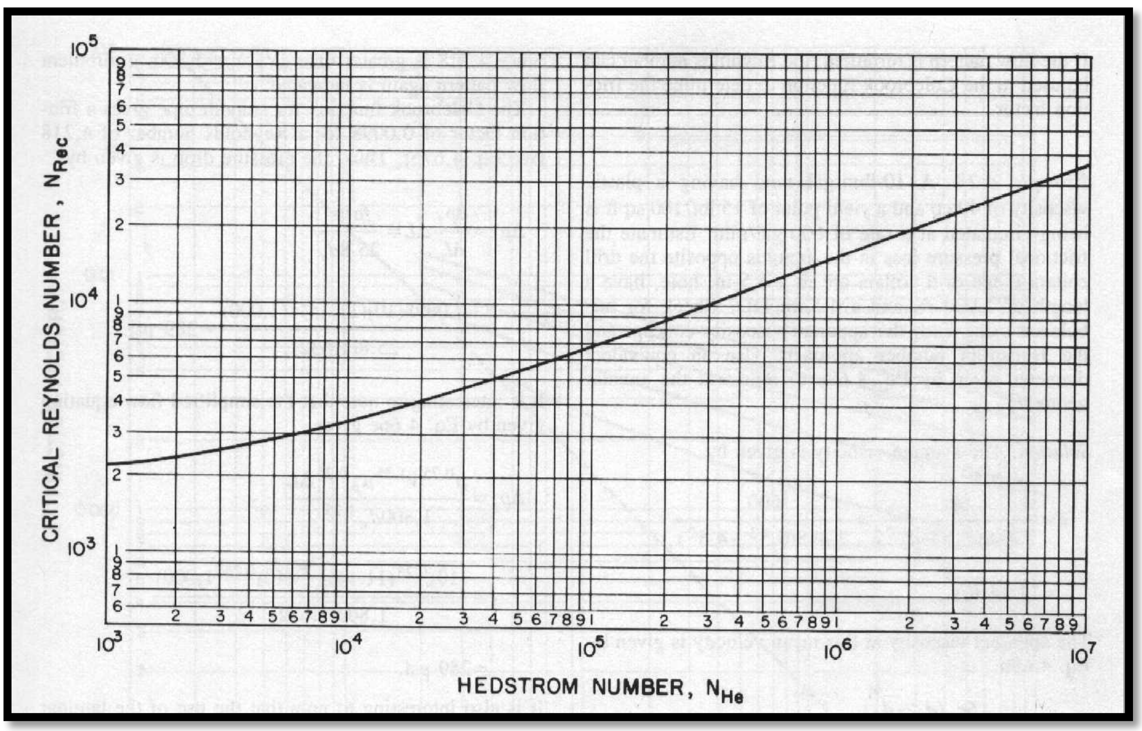
Q = flowrate, gpm; D_1= previous casing size or hole size, in; D_2= casing size, in

Hanks presented laminar-turbulence criteria for Bingham Plastic fluids. A dimensionless term, called Hedstrom number is introduced:

$$N_{He} = \frac{37100\,\rho D^2\,\tau_y}{\mu_p^{\;2}}$$

The critical Reynolds number, N_{cRe} for the given rheology is then found by the following graph after calculating the Hedstrom number:

Figure 15.Graph of Hedsrom number plot



If the obtained from graph Reynolds number using mean viscosity is larger than critical Reynolds number, flow is **turbulent:**

$$N_{Re} \geq N_{Re_c} \Rightarrow \text{flow is turbulent.}$$

So from here we have to ensure that the flow regime in the annulus between open hole/previous casing and casing will designed in a way in order to have the turbulent flow. We can manipulate the flowrate as well as cementing properties. The maximum allowed flowrate will be dependent upon the pump ratings of the rig as well as the fracture gradient of the formation.

3.4.2 Cementing Hydraulics:

We have to consider our pump hydraulics in order to not exceed the maximum pump pressure as well as maximum allowed pump flowrate. By calculating the pressure losses we can find out the Equivalent Circulating Density while pumping cement, in order not to exceed the fracture pressure of the formation drilled and cemented at the time.

3.4.2.1 Pump pressure required:

Drilling mud leaves the pump discharge, passes through the surface lines; standpipe and mud hose, and finally enters the drill string through the top of the kelly joint. From here it begins the long downward travel through the drill pipe, drill collars and expelled through the nozzles of the bit and return up to the surface through the annulus. Since the mud enters the drill string and leaves the annulus at the same level the only pressure required is to overcome the frictional losses in the system.

The discharge pressure at the pump is defined as:

$$\Delta P_t = \Delta P_s + \Delta P_p + \Delta P_c + \Delta P_b + \Delta P_{ac} + \Delta P_{ap}$$

Where ΔP_t = pump discharge pressure

ΔP_s = pressure loss in surface piping, stand pipe and mud hose

ΔP_p = pressure loss inside drill pipe

ΔP_c = pressure loss inside drill collar

ΔP_b = pressure loss across bit

ΔP_{ac} = pressure loss in annulus in the drill collars

ΔP_{ap} = pressure loss in annulus in the drill pipe

In our case, for the cementing procedures we have differences from the above assumption:

- **In our system we have cement instead of the drilling mud**
- **Pressure losses in surface cementing lines from cementing unit to cementing head is neglected**
- **The drillpipe is not used, as we are pumping right from the cementing head into the casing (disregard in case of liner running and cementing)**
- **No drill collars**
- **No bit, as the casing entrance is fully opened to rathole section at casing shoe**
- **Annulus is only between open hole/current casing and previous casing/current casing**
- **No centralizers are used**
- **The casing is considered centralized inside the previous casing/open hole (stand-off 100%)**

Thus the discharge pressure at the pump becomes:

$\Delta P_t = \Delta P_c + \Delta P_{ac} + \Delta P_{aoh}$

Where,

ΔP_c= pressure loss inside the casing

ΔP_{ac}=pressure loss in the annulus between the current cemented casing and previous casing

ΔP_{aoh} = pressure loss in the annulus between the run casing and the open hole section

The following formula is used to determine the pressure losses in the casing as well as annulus region for laminar flow regime (psi/ft):

Bingham Plastic	$\frac{\Delta P}{\Delta L} = \frac{\mu_p \overline{v}}{1500 d^2} + \frac{\tau_y}{225 d}$	$\frac{\Delta P}{\Delta L} = \frac{\mu_p \overline{v}}{1000(d_2 - d_1)^2} + \frac{\tau_y}{200(d_2 - d_1)}$

Where,

v = the mean velocity, ft/sec; d = inner diameter of casing, in; d_1 = outer diameter of the casing, in

d_2 = open hole size, in

The next formula is used to determine the pressure losses during the turbulent flow regime:

Pipe	Annulus
$\frac{\Delta P}{\Delta L} = \frac{f_f \rho \overline{v}^2}{25.8 D}$	$\frac{\Delta P}{\Delta L} = \frac{f_f \rho \overline{v}^2}{21.1(d_2 - d_1)}$

Where,

v= the mean velocity, ft/sec; D = inner diameter of casing, in; d_1 = outer diameter of the casing, in

d_2 = open hole size, in; f_f = friction factor

3.4.2.2 Friction Factor

Friction factor calculation (turbulent flow regime):

Colebrook equation (modified version of Nikuradze equation) is most widely used empirical correlation of friction factor for Newtonian fluids. Colebrook equation is given as:

$$\frac{1}{\sqrt{f_f}} = 4\log\left(N_{Re}\sqrt{f_f}\right) - 0.395$$

Blasius equations also can be used, but it is less accurate:

$$f_f = \frac{0.0791}{N_{Re}^{0.25}}$$

Friction factor calculation (laminar flow regime):

$$f_f = \frac{16}{N_{Re}}$$

After finding out all the pressure losses gradients, we multiply them respectively by the lengths they are affecting into and we get total pressure losses which will be equal to pump pressure.

3.4.3 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 + $P_{t.ann}$ / 0.052*TVD

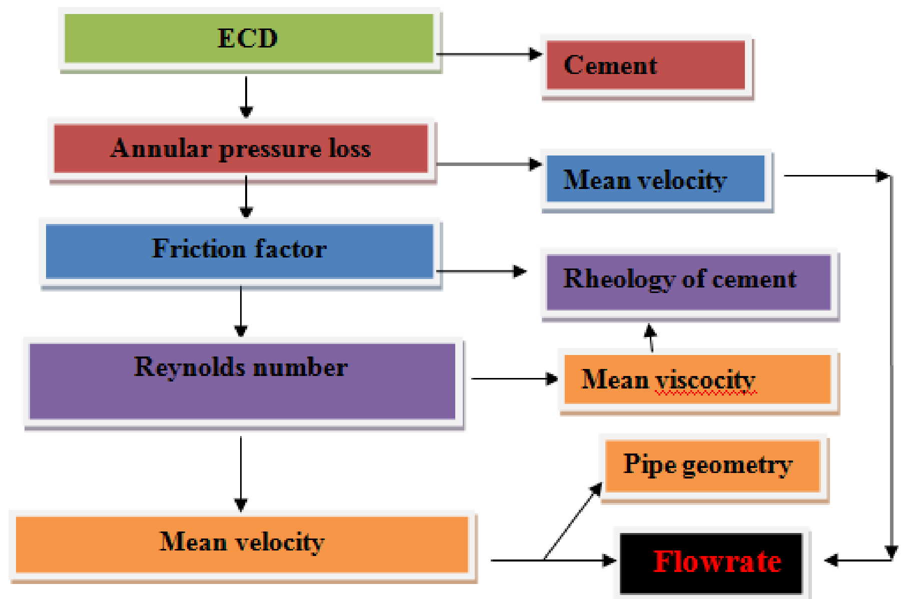
Where,

CW = weight of the cement, ppg; $P_{t.ann}$ = total annular pressure losses, psi

TVD = true vertical depth of the cemented depth, ft

3.4.4 The main factor determination

We reach the point where we have to talk about the factor dependence on each other as the following chart shows:



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.

3.5 Water channeling problem

The second part of my project with the objective of preventing the water channeling on the upper side of the annulus will be based totally on the studying, analyzing, comparing and summarizing the literature review: papers, works, researches, laboratory works, SPE presentations etc.

The result will be applied on the same system as the first part of my project as to simultaneously meet the both objectives of my project and prevent the presence of mud and water channeling.

3.6 Field data, manual calculation and Landmark software

For the cement volume calculations, the manual and the Landmark software results will be compared and appropriate conclusions will be made. The manual pressure losses, friction factor, ECD calculations will be compared with personally coded spreadsheet in Excel Macros (VBA) as shown in next *Figure 16*. (example):

Hydraulics

13 3/8" section	Hedstrom Number	Reynolds number	PRESS	Critical Reynolds	Flow Regime
inside casing	440729,28	2475,40	GRAPH	12000	Laminar
casing X OH	32480,42	444,71		4750	Laminar
casing X casing	142001,16	97,61		7500	Laminar
9 5/8" section	**Hedstrom Number**	**Reynolds number**		**Critical Reynolds**	**Flow Regime**
inside casing	193385,78	2960,90	GRAPH	8800	Laminar
casing X OH	11804,26	791,33		3500	Laminar
casing X casing	13334,87	732,56		3600	Laminar
7" section	**Hedstrom Number**	**Reynolds number**		**Critical Reynolds**	**Flow Regime**
inside drill pipe	48513,23	2094,38	GRAPH	5300	Laminar
inside liner	101466,76	1035,65		6950	Laminar
liner X OH	3985,31	407,13		2700	Laminar
liner X casing	5005,13	358,63		2900	Laminar
drillpipe X casing	24000,03	156,46		4400	Laminar

CALCULATE

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.

CHAPTER 4:

RESULTS AND DISCUSSION

4.1 Landmark Software start-up

First I will start with introduction to Landmark software, as I had taken a course of Landmark software of Halliburton in our university for two weeks that was organized by my FYP supervisor 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 my project is "Designing a cement program for Extended Reach Drilling 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 the well path data from the actual field data sheet 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)

A data I add manually to the software in a section called **WELLPATH EDITOR:**

Table 4. Well path data

Wellpath Editor

Identification

Name: Wellpath | Options...

Description: WELL : ABU-KECIL-2 (SLOT-2)

Well Depth (MD): 15651.8 ft | Generate with Actual Stations

VSection Definition

Origin N: 0.0 ft

Origin E: 0.0 ft

Azimuth: 61.02 °

	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	61.02	0.0	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
2	98.4	0.00	61.02	98.4	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
3	196.8	0.00	61.02	196.8	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
4	295.2	0.00	61.02	295.2	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
5	393.6	0.00	61.02	393.6	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
6	492.0	0.00	61.02	492.0	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
7	574.0	0.00	61.02	574.0	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
8	590.4	0.00	61.02	590.4	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
9	688.8	0.00	61.02	688.8	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
10	787.2	0.00	61.02	787.2	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
11	885.6	0.00	61.02	885.6	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
12	984.0	0.00	61.02	984.0	0.00	0.00	0.00	0.0	0.0	0.0	0.00	0.00
13	1082.4	3.00	61.02	1082.4	3.05	0.28	0.00	2.6	1.2	2.3	3.05	0.00
14	1180.8	6.00	61.02	1180.4	3.05	0.51	0.00	10.3	5.0	9.0	3.05	0.00
15	1279.2	9.00	61.02	1278.0	3.05	0.70	0.00	23.1	11.2	20.2	3.05	0.00
16	1377.6	12.00	61.02	1374.7	3.05	0.87	0.00	41.1	19.9	35.9	3.05	0.00
17	1476.0	15.00	61.02	1470.4	3.05	1.02	0.00	64.0	31.0	56.0	3.05	0.00
18	1574.4	18.00	61.02	1564.7	3.05	1.14	0.00	92.0	44.6	80.5	3.05	0.00
19	1672.8	21.00	61.02	1657.5	3.05	1.26	0.00	124.8	60.5	109.2	3.05	0.00
20	1771.2	24.00	61.02	1748.4	3.05	1.36	0.00	162.5	78.7	142.1	3.05	0.00
21	1869.6	27.00	61.02	1837.2	3.05	1.44	0.00	204.8	99.2	179.2	3.05	0.00
22	1968.0	30.00	61.02	1923.7	3.05	1.52	0.00	251.8	122.0	220.3	3.05	0.00
23	2066.4	33.00	61.02	2007.5	3.05	1.60	0.00	303.2	146.9	265.2	3.05	0.00
24	2164.8	36.00	61.02	2088.6	3.05	1.66	0.00	358.9	173.9	314.0	3.05	0.00
25	2263.2	39.00	61.02	2166.7	3.05	1.72	0.00	418.8	202.9	366.4	3.05	0.00
26	2361.6	42.00	61.02	2241.5	3.05	1.78	0.00	482.7	233.9	422.3	3.05	0.00
27	2460.0	45.00	61.02	2312.9	3.05	1.83	0.00	550.4	266.7	481.5	3.05	0.00
28	2558.4	48.00	61.02	2380.6	3.05	1.88	0.00	621.8	301.3	543.9	3.05	0.00
29	2656.8	51.00	61.02	2444.5	3.05	1.92	0.00	696.6	337.5	609.4	3.05	0.00
30	2755.2	54.00	61.02	2504.4	3.05	1.96	0.00	774.7	375.3	677.7	3.05	0.00
31	2853.6	57.00	61.02	2560.1	3.05	2.00	0.00	855.8	414.6	748.6	3.05	0.00
32	2952.0	60.00	61.02	2611.5	3.05	2.03	0.00	939.7	455.3	822.0	3.05	0.00
33	3050.4	63.00	61.02	2658.5	3.05	2.07	0.00	1026.1	497.2	897.6	3.05	0.00
34	3148.8	66.00	61.02	2700.8	3.05	2.10	0.00	1114.9	540.2	975.3	3.05	0.00
35	3247.2	69.00	61.02	2738.5	3.05	2.12	0.00	1205.8	584.2	1054.8	3.05	0.00
36	3345.6	72.00	61.02	2771.3	3.05	2.15	0.00	1298.6	629.2	1136.0	3.05	0.00
37	3444.0	75.00	61.02	2799.3	3.05	2.18	0.00	1392.9	674.9	1218.5	3.05	0.00
38	3532.3	77.69	61.02	2820.1	3.05	2.20	0.00	1478.7	716.4	1293.5	3.05	0.00
39	3542.4	77.69	61.02	2822.3	0.00	2.19	0.00	1488.6	721.2	1302.2	0.00	0.00
40	3640.8	77.69	61.02	2843.2	0.00	2.13	0.00	1584.7	767.8	1386.3	0.00	0.00
41	3739.2	77.69	61.02	2864.2	0.00	2.08	0.00	1680.8	814.4	1470.4	0.00	0.00
42	3837.6	77.69	61.02	2885.2	0.00	2.02	0.00	1777.0	861.0	1554.5	0.00	0.00
43	3936.0	77.69	61.02	2906.2	0.00	1.97	0.00	1873.1	907.5	1638.6	0.00	0.00
44	4034.4	77.69	61.02	2927.2	0.00	1.93	0.00	1969.3	954.1	1722.7	0.00	0.00
45	4132.8	77.69	61.02	2948.1	0.00	1.88	0.00	2065.4	1000.7	1806.8	0.00	0.00
46	4231.2	77.69	61.02	2969.1	0.00	1.84	0.00	2161.5	1047.3	1890.9	0.00	0.00
47	4329.6	77.69	61.02	2990.1	0.00	1.79	0.00	2257.7	1093.8	1975.0	0.00	0.00
48	4428.0	77.69	61.02	3011.1	0.00	1.75	0.00	2353.8	1140.4	2059.1	0.00	0.00
49	4526.4	77.69	61.02	3032.1	0.00	1.72	0.00	2449.9	1187.0	2143.2	0.00	0.00
50	4624.8	77.69	61.02	3053.0	0.00	1.68	0.00	2546.1	1233.6	2227.3	0.00	0.00
51	4723.2	77.69	61.02	3074.0	0.00	1.64	0.00	2642.2	1280.2	2311.4	0.00	0.00
52	4821.6	77.69	61.02	3095.0	0.00	1.61	0.00	2738.4	1326.7	2395.5	0.00	0.00

<u>Next main data to be inputted are pore pressure profile of the drilled section (*Table 5*):</u>

Pore Pressure

	Vertical Depth (ft)	Pore Pressure (psi)	EMW (ppg)
1	338.9	132.04	7.50
2	2473.0	1132.00	8.81
3	3000.0	1404.00	9.01
4	3500.0	1674.00	9.21
5	4028.0	1937.00	9.26
6	4226.0	2088.00	9.51
7	4321.0	2294.00	10.22
8	4360.0	2347.00	10.36
9	4400.0	2393.00	10.47
10	4764.0	2651.00	10.71
11	5017.0	2752.00	10.56
12	5099.0	2789.00	10.53
13	5118.0	2795.00	10.51
14			

<u>And fracture pressure profile (*Table 6*):</u>

Fracture Gradient

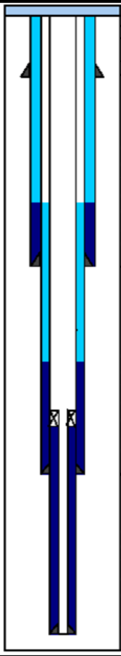
	Vertical Depth (ft)	Fracture Pressure (psi)	EMW (ppg)
1	338.9	202.46	11.50
2	2473.0	1567.30	12.20
3	3000.0	1926.23	12.36
4	3500.0	2252.73	12.39
5	4028.0	2732.76	13.06
6	4226.0	2878.07	13.11
7	4321.0	3032.56	13.51
8	4360.0	3082.58	13.61
9	4400.0	3122.28	13.66
10	4764.0	3392.96	13.71
11	5017.0	3521.02	13.51
12	5099.0	3605.06	13.61
13	5118.0	3669.01	13.80
14			

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

Next step is to come up with the casing setting depths and the fluid properties that will be used in each of the cementing sections, such as:

- **Drilling Mud**
- **Spacer**
- **Lead Cement Slurry**
- **Tail Cement Slurry**
- **Single Slurry**

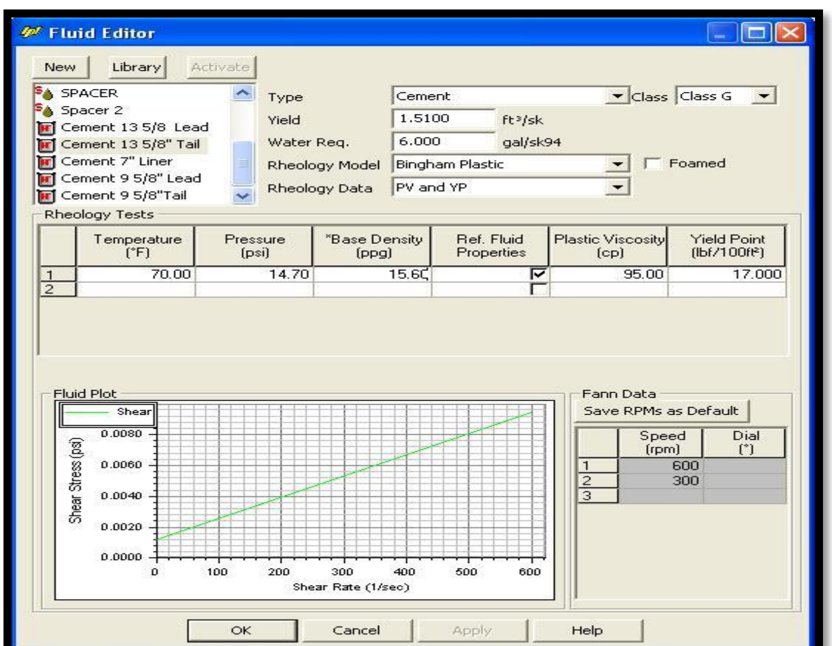
4.1.2 Casing and Fluids Data:



	Casing Type	MD	TVD	Temp (degF)		Slurry Design					TOC
RKB	42.3 m	BDF	BDF	BHST	BHCT						
Water Depth	61.0 m										
24" Drive Pipe 219ppf, X-56, R3, XLC-S											
Csg ID	23 in	175	175								
	Height of Collar	25				Density (ppg)	Lead	12.6	Tail	15.8	Lead
						Yield (ft³/sk)	Lead	2.14	Tail	1.19	0 m
OH	17 1/2 in					Composition :	Lead	Class G + 1.00gps BJ XL + 0.10gps R-21LS + 0.05gps FP-9LS			at surface (seadeck)
Csg OD	13 3/8 in						Tail	Class G + 0.40gps BJ XL + 0.35gps CD-33L + 0.05gps R-21LS + 0.05gps FP-9LS			
Type	68ppf, N-80, BTC					Fluid Loss (cc)	Lead	< 250	Tail	< 150	Tail
Csg ID	12.415 in					T. Time (Hrs)	Lead	6:00 - 6:15	Tail	4:00 - 4:30	150 m
Csg x Csg	1.1159 bbl/m					PV/Yp(cp / lbf/100 ft²)	Lead	60 10	Tail	100 25	above 13-3/8"
Ann. Cap.	0.4059 bbl/m										
Csg Cap.	0.4912 bbl/m	1500	881	148	113	24 hr Comp Strength	Lead	550	Tail	2000	csg shoe
	Height of Collar	25				Density (ppg)	Lead	12.6	Tail	14.5	Lead
						Yield (ft³/sk)	Lead	2.15	Tail	1.51	150 m
						Composition :	Lead	Class G + 1.20gps BJ-2000 + 0.10gps R-21LS + 0.05gps R-21LS + 0.05 FP-6LS			inside 13-3/8" csg
OH	12 1/4 in						Tail	Class G + 0.60gps BJ XL + 0.80gps BA-58L + 0.25gps CD-33L + 0.05gps R-21LS + 0.05gps FP-9LS			
Csg OD	9 5/8 in										
Type	47ppf, N-80, Vam Top										Tail
Csg ID	8.681 in					Fluid Loss (cc)	Lead	< 250	Tail	<100	150 m
Csg x Csg	0.1960 bbl/m					T.Time (Hrs)	Lead	5:00-5:15	Tail	4:00-4:30	above top most
Ann. Cap.	0.1830 bbl/m					PV/Yp(cp / lbf/100 ft²)	Lead	62 12	Tail	95 17	HC zones at
Csg Cap.	0.2402 bbl/m	3700	1405	189	141	24 hr Comp Strength	Lead	550	Tail	> 2000	3219 m
	Height of Collar	36				Density (ppg)	Single	14.5			
						Yield (ft³/sk)	Single	1.51			
OH	8 1/2 in					Composition :	Single	Class G + 0.60gps BJ XL+ 0.80gps BA-58L + 0.25gps CD-33L + 0.10gps R-21LS + 0.05gps FP-9LS			Single
Csg OD	7.0 in										150 m
Type	29ppf, L-80, New Vam										above 9-5/8"
Csg ID	6.184 in					Fluid Loss (cc)	Single	< 100			csg shoe,
Csg x Csg	0.0840 bbl/m					T.Time (Hrs)	Single	4:00-4:30			at top of liner
Ann. Cap.	0.0741 bbl/m					PV/Yp(cp / lbf/100 ft²)	Single	95 17			
Csg Cap.	0.1219 bbl/m	4692	1640	207	176	24 hr Comp Strength	Single	> 2000			

Table 7. Casing and fluid data

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



4.1.3 Well trajectory and path

The next figure represents 2D trajectory of the wellbore with the tagged casing shoe depths and casing sizes:

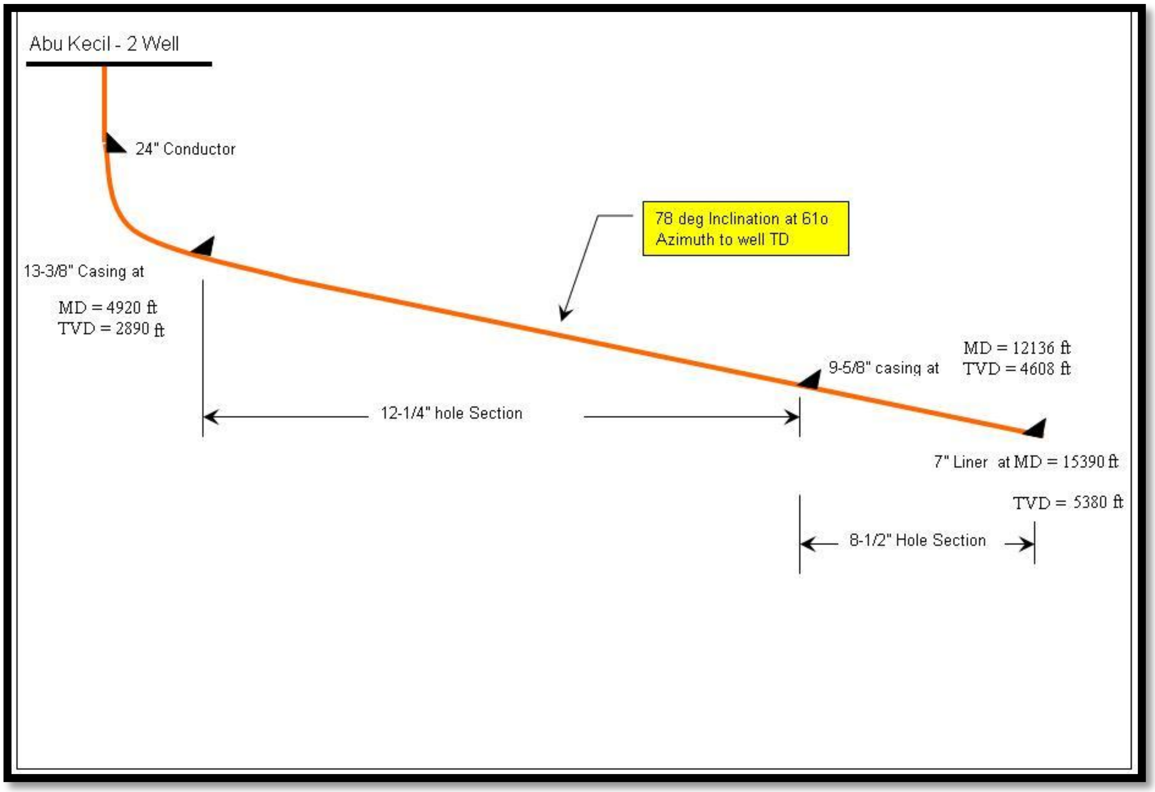
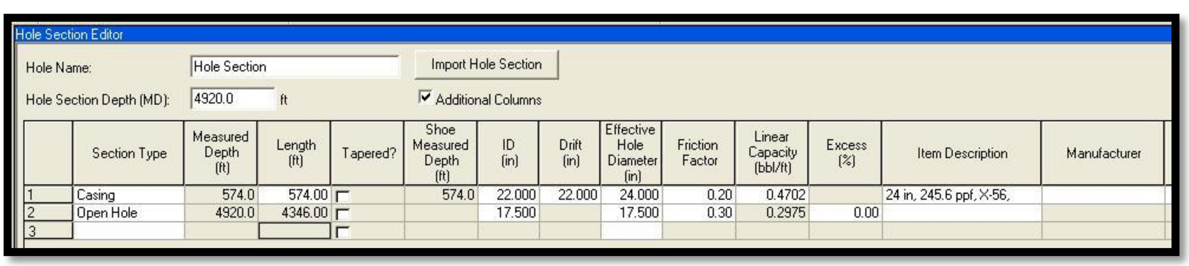


Figure 17. Well path and trajectory

4.1.4 Cementing 13 3/8" Casing

Starting from this point we can start cementing our well with 13 3/8" casing running, as the 24" conductor casing is driven into the earth to the vertical depth of 574 ft.

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



Hole Section Editor

Hole Name: Hole Section

Import Hole Section

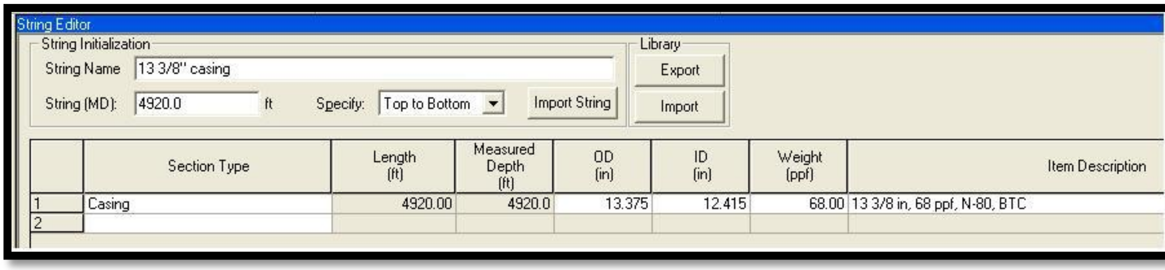
Hole Section Depth (MD): 4920.0 ft

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	Manufacturer
1	Casing	574.0	574.00		574.0	22.000	22.000	24.000	0.20	0.4702		24 in, 245.6 ppf, X-56,	
2	Open Hole	4920.0	4346.00			17.500		17.500	0.30	0.2975	0.00		
3													

The given data there indicates that the previous 24" casing was set at 574 ft and the 17, 5" open hole was drilled until the MD of 4920 ft.

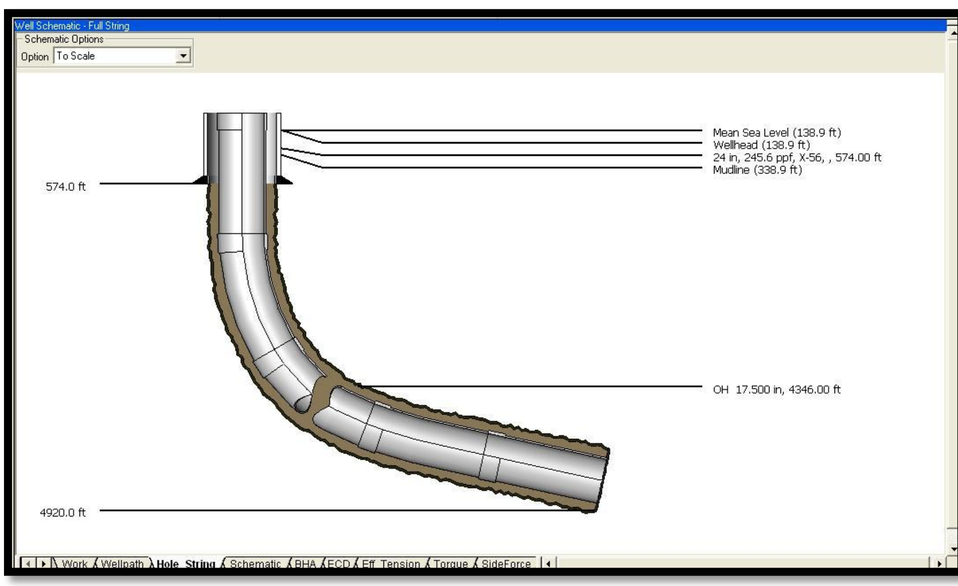
The next step is to edit the string that will be inserted into the new drilled section:



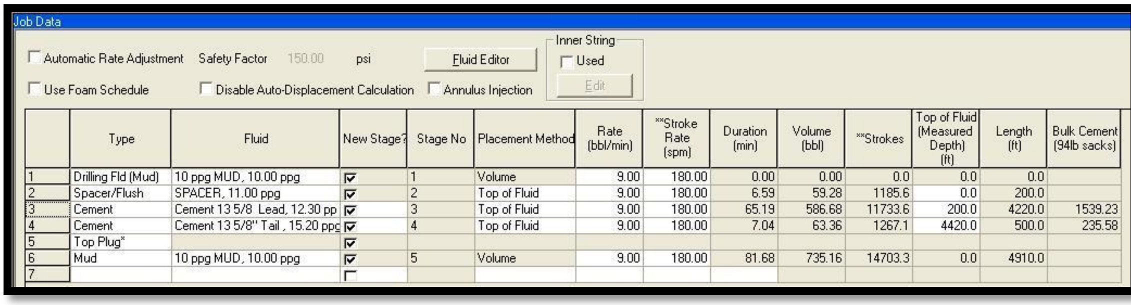
	Section Type	Length (ft)	Measured Depth (ft)	OD (in)	ID (in)	Weight (ppf)	Item Description
1	Casing	4920.00	4920.0	13.375	12.415	68.00	13 3/8 in, 68 ppf, N-80, BTC
2							

The given table indicates that the only string that will be inserted into the 17, 5" hole is 13 3/8" casing with 68 ppf poundage with the casing shoe at 4920 ft.

At this point we are already able to see the schematic diagram (*Figure 18*) of the section from surface until the 13 3/8" casing shoe.



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 13 3/8" casing cementing:



Job Data

☐ Automatic Rate Adjustment Safety Factor 150.00 psi Fluid Editor Inner String ☐ Used Edit

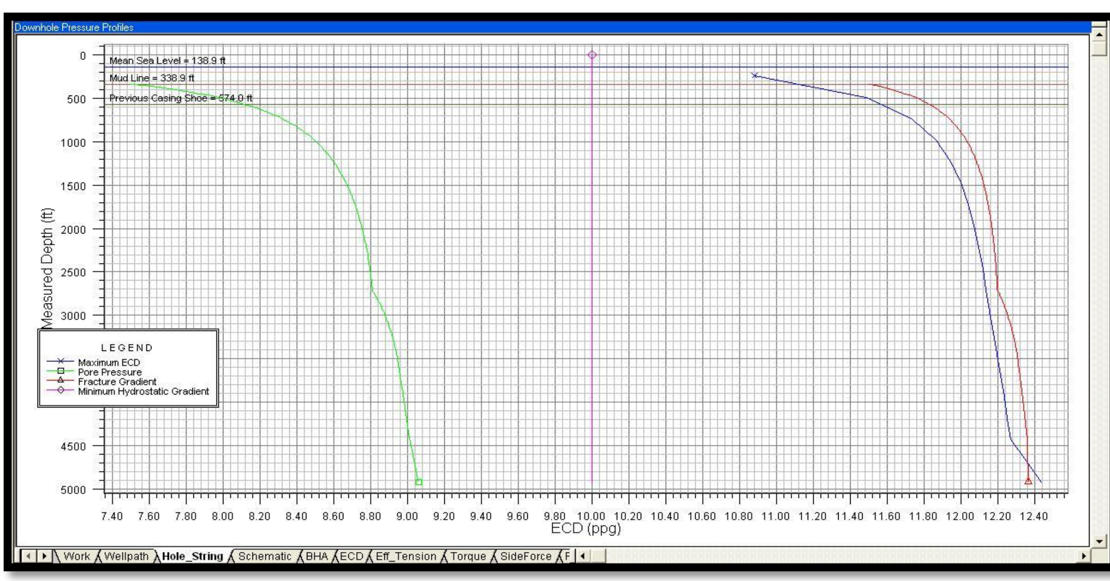
☐ Use Foam Schedule ☐ Disable Auto-Displacement Calculation ☐ Annulus Injection

	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)	10 ppg MUD, 10.00 ppg	☑	1	Volume	9.00	180.00	0.00	0.00	0.0	0.0	0.0	
2	Spacer/Flush	SPACER, 11.00 ppg	☑	2	Top of Fluid	9.00	180.00	6.59	59.28	1185.6	0.0	200.0	
3	Cement	Cement 13 5/8 Lead, 12.30 pp	☑	3	Top of Fluid	9.00	180.00	65.19	586.68	11733.6	200.0	4220.0	1539.23
4	Cement	Cement 13 5/8" Tail , 15.20 ppg	☑	4	Top of Fluid	9.00	180.00	7.04	63.36	1267.1	4420.0	500.0	235.58
5	Top Plug*		☑										
6	Mud	10 ppg MUD, 10.00 ppg	☑	5	Volume	9.00	180.00	81.68	735.16	14703.3	0.0	4910.0	
7			☐										

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). The annulus is cemented until the surface and there is no drilling mud in an annulus section. 200 ft of spacer, followed by 4220 ft of lead cement which reaches 374 ft inside of previous casing shoe from the depth of 4420 where tail slurry has its TOC 500 ft above the 13 3/8" casing shoe as usual company policy indicates.

For the ease of calculation and software usage, interior of the casing is fully filled with mud until TD, and there is no cement after cementing job is performed. Cement slurry section starts from the TD (casing shoe) in all 3 sections (9 5/8" casing, 7" liner).

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 (*Figure 19*) was obtained from the OptiCem software using the combination of all previous input data:



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. Thus during pumping the cement this indication could lead to a fracture of formation and further drilling problems like lost 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 it is better to change all of them a little bit, without causing the other problems. And each of the factors that we will decrease 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

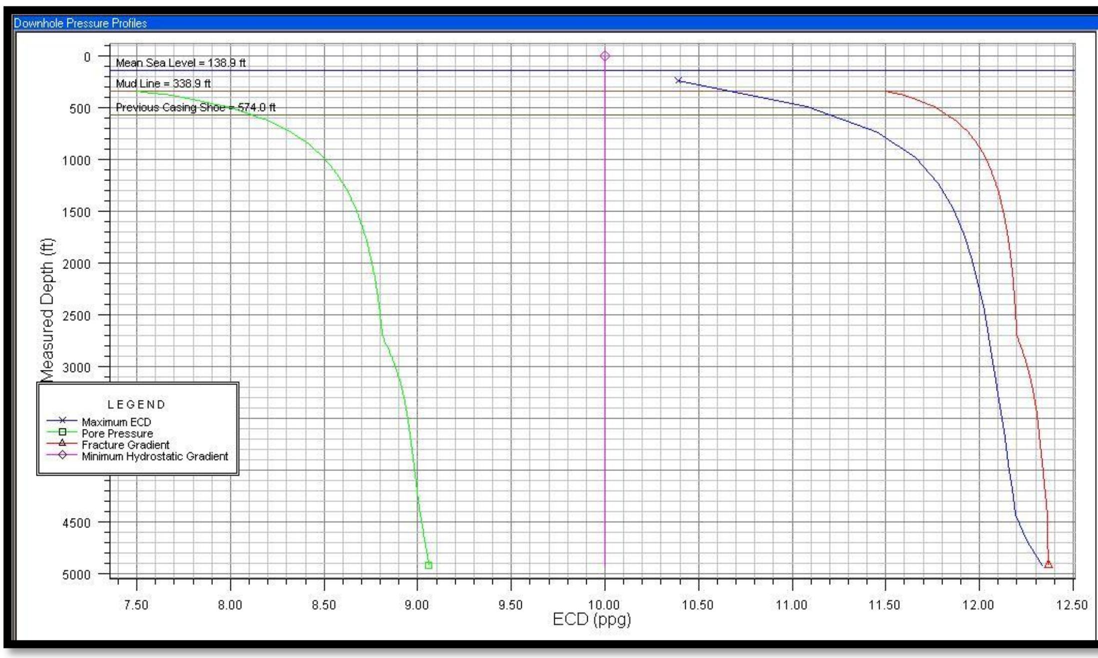
	Type	Fluid	New Stage?	Stage No	Placement Method	Rate (bbl/min)	**Stroke Rate (spm)	Duration (min)	Volume (bbl)	**Strokes	Top of Fluid (Measured Depth) (ft)	Length (ft)	Bulk Cement (94lb sacks)
1	Drilling Fld (Mud)	10 ppg MUD, 10.00 ppg	☑	1	Volume	8.00	160.00	0.00	0.00	0.0	0.0	100.0	
2	Spacer/Flush	Spacer 2, 10.50 ppg	☑	2	Top of Fluid	8.00	160.00	7.41	59.28	1185.6	100.0	200.0	
3	Cement	Cement 13 5/8 Lead, 12.00 pp	☑	3	Top of Fluid	8.00	160.00	71.18	569.41	11388.2	300.0	4220.0	1493.93
4	Cement	Cement 13 5/8" Tail , 15.00 ppg	☑	4	Top of Fluid	8.00	160.00	6.37	50.99	1019.7	4520.0	400.0	189.58
5	Top Plug*		☑										
6	Mud	10 ppg MUD, 10.00 ppg	☑	5	Volume	8.00	160.00	91.90	735.16	14703.3	0.0	4910.0	
7			☐										

The modifications to the data made:

- **The spacer weight was decreased from 11 ppg to 10.5 ppg**
- **The Tail Cement height was decreased from 500 ft to 400 ft**

- **The previous modification lead to a 100 ft of drilling mud to appear in the upper part of the annulus until the surface**
- **Lead Cement weight was decreased from 12.30 ppg to 12.00 ppg**
- **Tail Cement weight was decreased from 15.20 ppg to 15.00 ppg**
- **The flowrate was decreased from 17 bbl/min (714 gpm) to 15 bbl/min (630 gpm)**

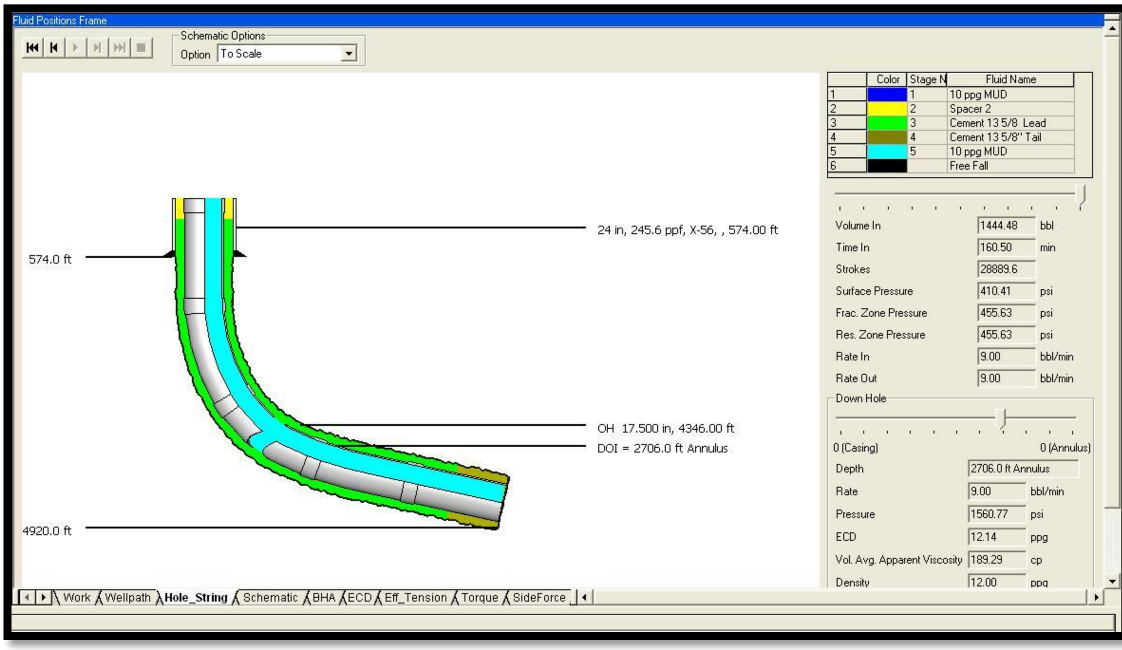
The pressure profile plot then was launched again, and this is the plot (*Figure 20*) I obtained:



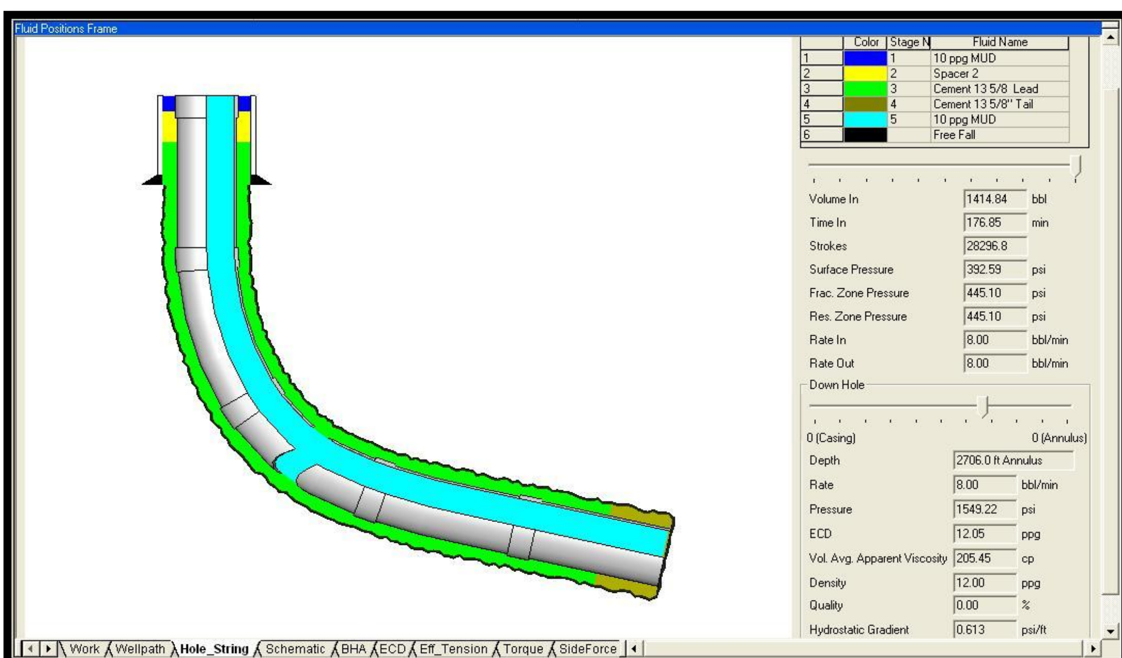
This time we can see that ECD is not exceeding the fracture gradient and we can perform the cementing job with the latest data and procedures with no taking a risk to fracture the formation that can lead to well problems.

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

1) First case (with over-ECD) (*Figure 21*)



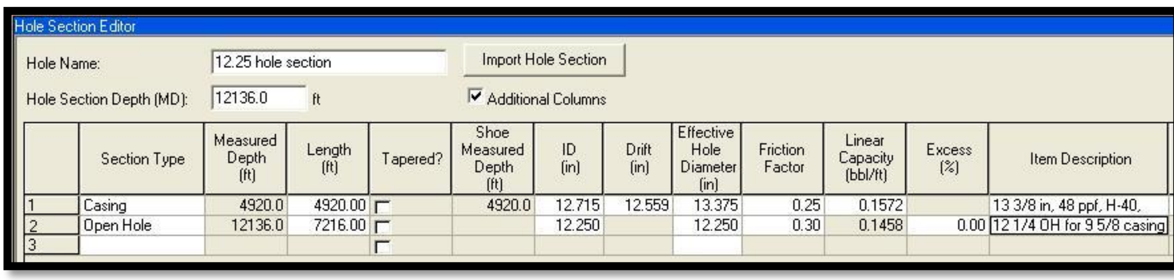
2) Second case (simulated ECD)



As you can see from the modified schematic diagram, compared to the first one, it includes some drilling mud on the top of the section from surface to bottom (100 ft) and the tail slurry is 100 ft shorter than the first design, which eventually decreases the average fluid density and ECD.

4.1.5 Cementing 9 5/8" Casing

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



Hole Section Editor

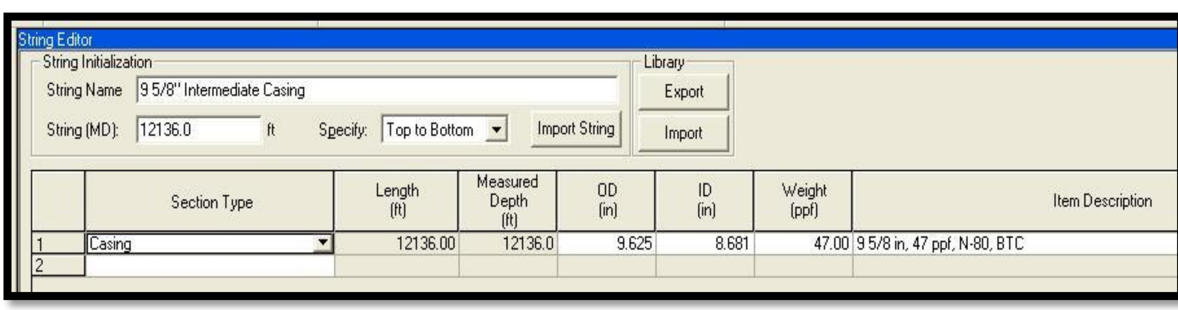
Hole Name: 12.25 hole section | Import Hole Section

Hole Section Depth (MD): 12136.0 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
1	Casing	4920.0	4920.00		4920.0	12.715	12.559	13.375	0.25	0.1572		13 3/8 in, 48 ppf, H-40,
2	Open Hole	12136.0	7216.00			12.250		12.250	0.30	0.1458	0.00	12 1/4 OH for 9 5/8 casing
3												

In the table we can see that prior to cementing the section consists of previous 13 3/8" casing with the casing seat depth of 4920 ft, and the 12.25 open hole drilled section until 12136 ft.

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



String Editor

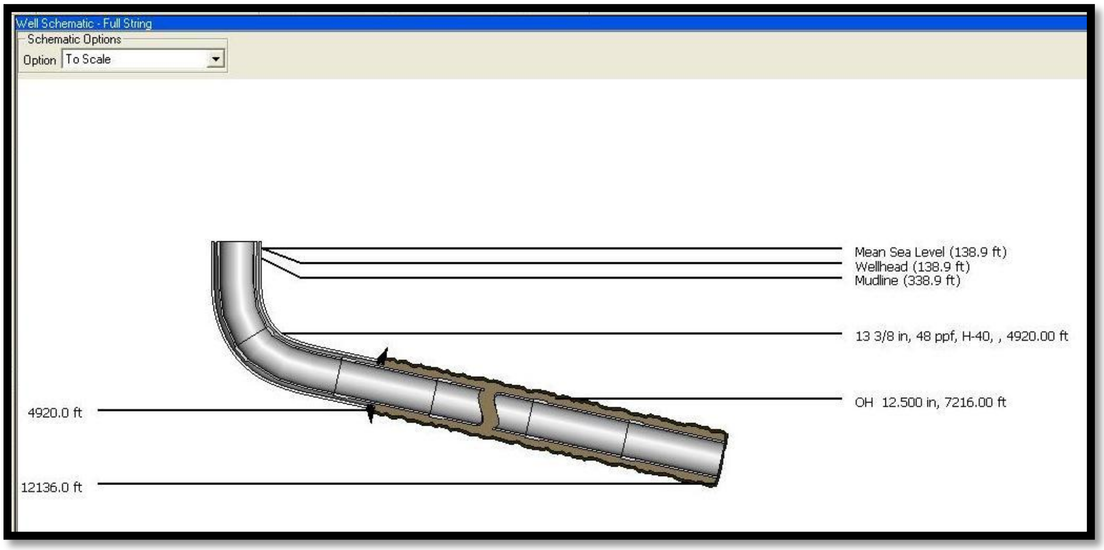
String Initialization: String Name: 9 5/8" Intermediate Casing | String (MD): 12136.0 ft | Specify: Top to Bottom | Import String

Library: Export | Import

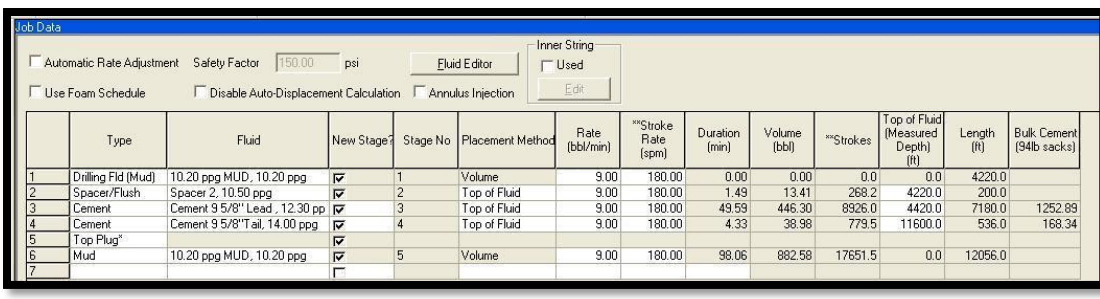
	Section Type	Length (ft)	Measured Depth (ft)	OD (in)	ID (in)	Weight (ppf)	Item Description
1	Casing	12136.00	12136.0	9.625	8.681	47.00	9 5/8 in, 47 ppf, N-80, BTC
2							

Here we can observe that the only string inserted into the 12.25" hole section would be 9 5/8" casing with the following grade/type properties: 47 ppf, N-80, BTC and casing shoe depth of 12136 ft.

At this point we are already able to see the schematic diagram (*Figure 23*) of the section from surface until the 9 5/8" casing shoe:



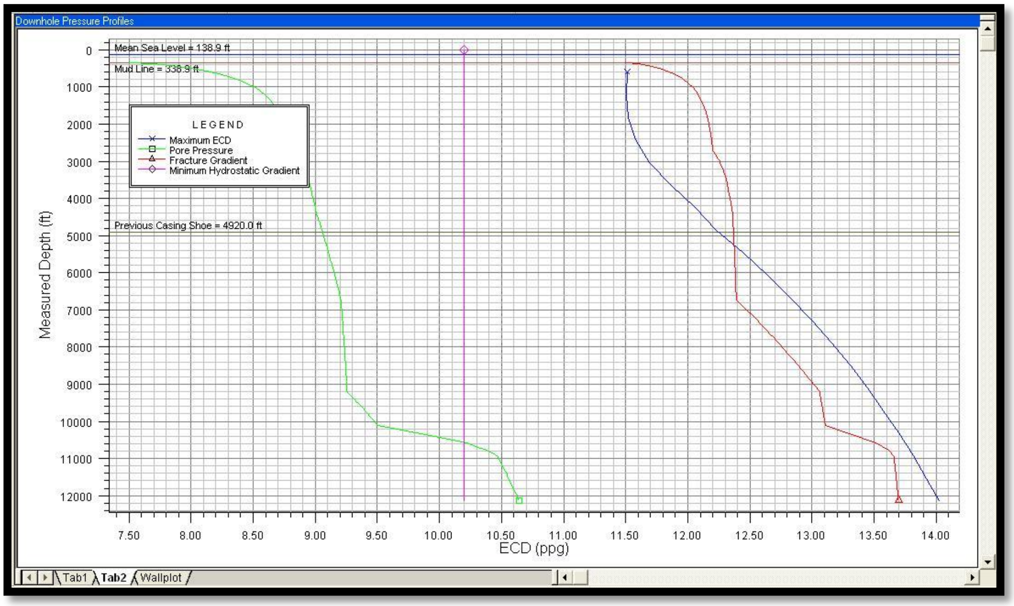
Now we can edit Job Data and indicate the fluid flow and sequence properties:



	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)	10.20 ppg MUD, 10.20 ppg	☑	1	Volume	9.00	180.00	0.00	0.00	0.0	0.0	4220.0	
2	Spacer/Flush	Spacer 2, 10.50 ppg	☑	2	Top of Fluid	9.00	180.00	1.49	13.41	268.2	4220.0	200.0	
3	Cement	Cement 9 5/8" Lead , 12.30 pp	☑	3	Top of Fluid	9.00	180.00	49.59	446.30	8926.0	4420.0	7180.0	1252.89
4	Cement	Cement 9 5/8"Tail, 14.00 ppg	☑	4	Top of Fluid	9.00	180.00	4.33	38.98	779.5	11600.0	536.0	168.34
5	Top Plug*		☑										
6	Mud	10.20 ppg MUD, 10.20 ppg	☑	5	Volume	9.00	180.00	98.06	882.58	17651.5	0.0	12056.0	
7			☐										

From the given table, we get the information about the stages of pumping fluids. Drilling mud reaches the surface from MD of 4220, after that 200 ft of spacer is followed by 7180 ft of lead cement with the TOC of 500 ft above previous 13 3/8" casing shoe. The latest bottom portion of the annulus is filled with 536 ft of heavy tail cement. The pumping rate is constant for all the fluids and equal to 12 bbl/min (504 gpm).

After we set all the data in **Job Data**, we are ready to see the plot of pressure profile (*Figure 24*):



From the graph we can clearly see the ECD during pumping the cement is exceeding the fracture gradient of the formation in an open hole. Thus we have to do some modifications and simulation to decrease the ECD to appropriate levels, such as:

- **Decreasing flowrate**

In this case I did not play and manipulate with other data like in the previous cemented section. Decreasing the flowrate to 10 bbl/min (420 gpm) from 12 bbl/min (504 gpm) was enough to achieve suitable ECD gradient:

Job Data

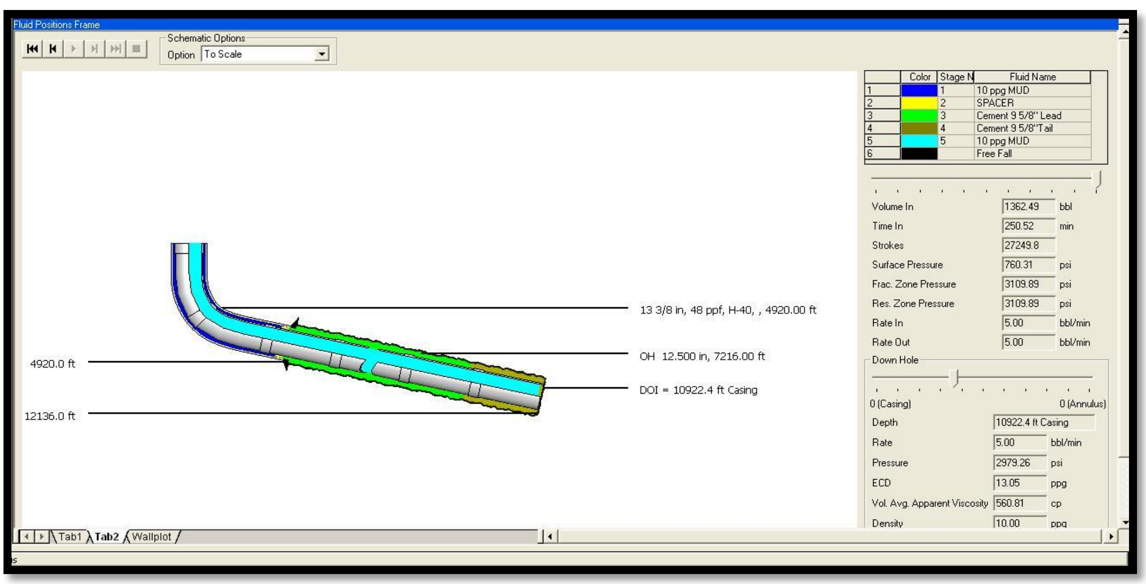
☐ Automatic Rate Adjustment Safety Factor 150.00 psi Fluid Editor
Inner String ☐ Used Edit
☐ Use Foam Schedule ☐ Disable Auto-Displacement Calculation ☐ Annulus Injection

	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)	10.20 ppg MUD, 10.20 ppg	☑	1	Volume	7.00	140.00	0.00	0.00	0.0	0.0	4220.0	
2	Spacer/Flush	Spacer 2, 10.50 ppg	☑	2	Top of Fluid	7.00	140.00	1.92	13.41	268.2	4220.0	200.0	
3	Cement	Cement 9 5/8" Lead , 12.30 pp	☑	3	Top of Fluid	7.00	140.00	63.76	446.30	8926.0	4420.0	7180.0	1252.89
4	Cement	Cement 9 5/8"Tail, 14.00 ppg	☑	4	Top of Fluid	7.00	140.00	5.57	38.98	779.5	11600.0	536.0	168.34
5	Top Plug*		☑										
6	Mud	10.20 ppg MUD, 10.20 ppg	☑	5	Volume	7.00	140.00	126.08	882.58	17651.5	0.0	12056.0	
7			☐										

This is the plot of the pressure profile (*Figure 25*) after the modification to the flowrate was made with the decreased ECD which is less that the fracture gradient of the formation and would not lead to any cementing and further drilling problems:

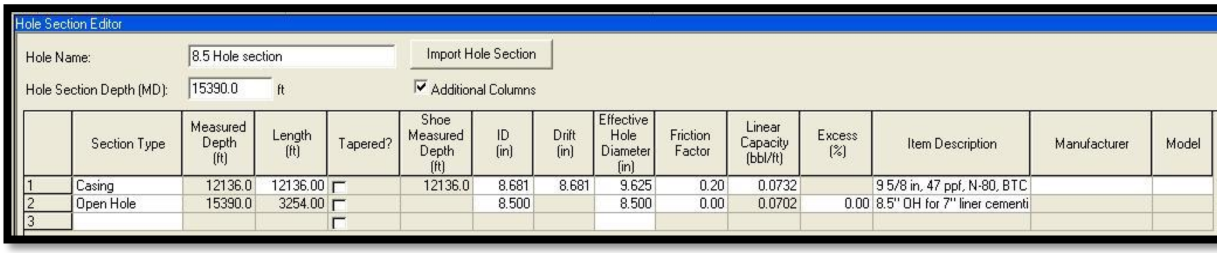
ECD suitability can be clearly seen here and that the decreasing the flowrate directly influence to ECD is somehow proved and analyzed.

The next figure represents the fluid positions frame (Figure26) 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:



4.1.6 Cementing 7" Liner

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



Hole Section Editor

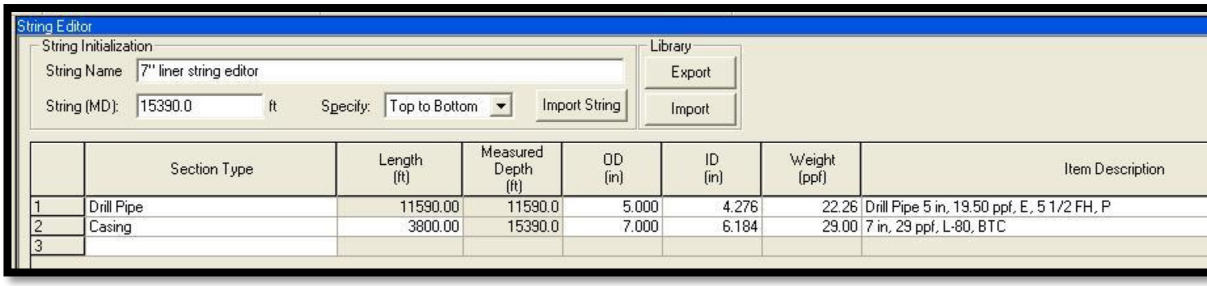
Hole Name: 8.5 Hole section | Import Hole Section

Hole Section Depth (MD): 15390.0 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	Manufacturer	Model
1	Casing	12136.0	12136.00		12136.0	8.681	8.681	9.625	0.20	0.0732		9 5/8 in, 47 ppf, N-80, BTC		
2	Open Hole	15390.0	3254.00			8.500		8.500	0.00	0.0702	0.00	8.5" OH for 7" liner cementi		
3														

From table we can see two sections which are involved in 7" liner cementing operation:

- The previous 9 5/8" casing from surface to casing shoe depth of 12136 ft
- Open hole drilled after the previous casing was set with ID of 8.5" until MD of 15390 ft



String Editor

String Initialization

String Name: 7" liner string editor

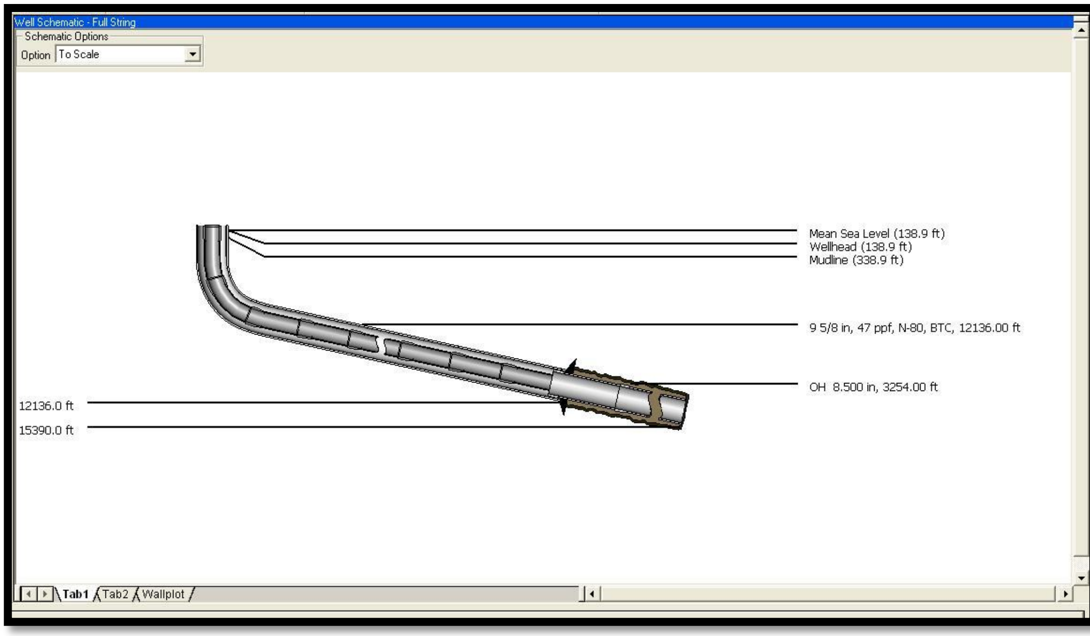
String (MD): 15390.0 ft | Specify: Top to Bottom | Import String

Library: Export | Import

	Section Type	Length (ft)	Measured Depth (ft)	OD (in)	ID (in)	Weight (ppf)	Item Description
1	Drill Pipe	11590.00	11590.0	5.000	4.276	22.26	Drill Pipe 5 in, 19.50 ppf, E, 5 1/2 FH, P
2	Casing	3800.00	15390.0	7.000	6.184	29.00	7 in, 29 ppf, L-80, BTC
3							

Our String Editor data this time has some add-ons in terms of the 5" drill pipe until the liner setting depth of 11590 ft (TOL). The liner together with liner hanger is attached to the drillpipe and lowered to the designated depth and set there by specific procedures usually accompanied by drillpipe turning and that is how the liner sets at the pre-panned depth on the specific tool. The liner shoe is at the total depth TD which is 15390 ft.

From already input data for 7" liner, we can now design well schematic (*Figure 27*) for that specific portion of the wellbore using OptiCem module:



Job Data filling is the next step:

Job Data

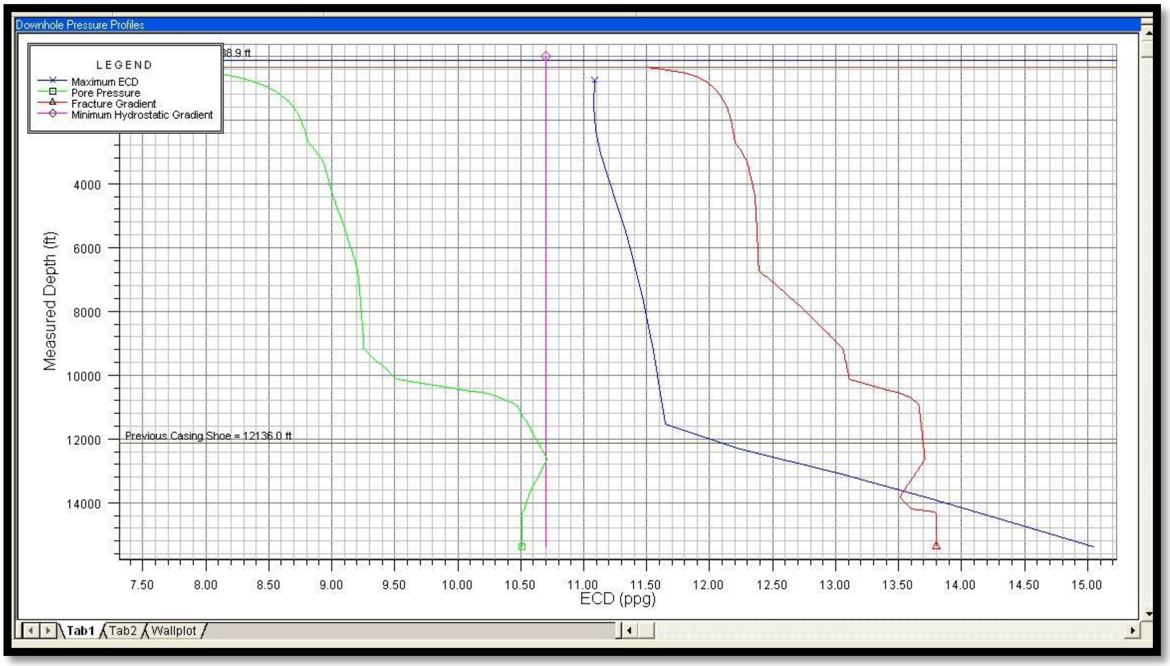
Automatic Rate Adjustment Safety Factor 0.00 psi Fluid Editor Inner String Used

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)	10.7 Drilling mud, 10.70 ppg	☑	1	Volume	5.00	100.00	0.00	0.00	0.0		11440.0	
2	Spacer/Flush	SPACER, 11.00 ppg	☑	2	Top of Fluid	5.00	100.00	1.72	8.62	172.4	11440.0	200.0	
3	Cement	Cement 7" Liner, 14.50 ppg	☑	3	Top of Fluid	5.00	100.00	17.24	86.19	1723.9	11640.0	3750.0	320.49
4	Top Plug*		☑										
5	Mud	10.7 Drilling mud, 10.70 ppg	☑	4	Volume	5.00	100.00	64.26	321.31	6426.2	0.0	15390.0	
6			☐										

Here we see the pumping sequences that are personally designed based on usual cementing job operations. The flowrate chosen is 5 bbl/min (210 gpm) as the area is decreased as we go deeper with smaller casing sizes and larger flowrate could cause too high velocity profile and ECD exceeding the fracture gradient. Drilling fluid (10.70 ppg) occupies 11440 ft of the annulus zone from the surface and then followed by 200 ft of 11 ppg spacer. 11640 ft is the TOC in the annulus zone which reaches around 500 ft inside the previous 9 5/8" casing from TD of 15390 ft.

After we set all the data in **Job Data**, we are ready to see the plot of pressure profile (*Figure 28*):



Downhole pressure profile plot indicates that the cementing design is not appropriate as the ECD is higher than our fracture gradient in the open hole part, which is crucial in assuring quality of cementing job that could cause overall well problems.

The same modifications/changes should be made as in previous casing cementing job by decreasing the flowrate from 5 bbl/min (210 gpm) to 3.5 bbl/min (147 gpm), the new Job Data is in the following table:

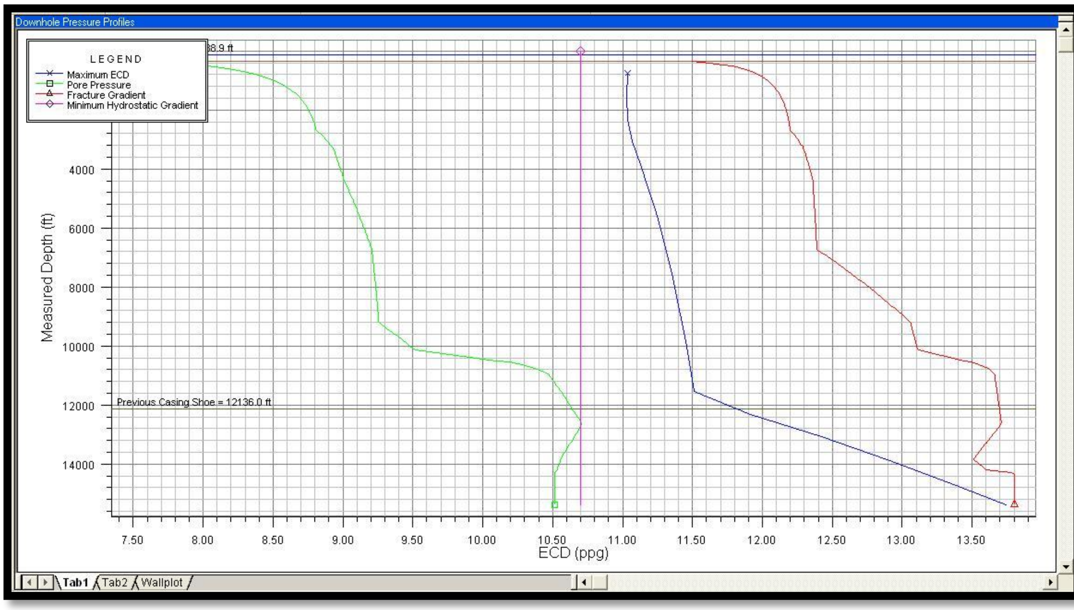
Job Data

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

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

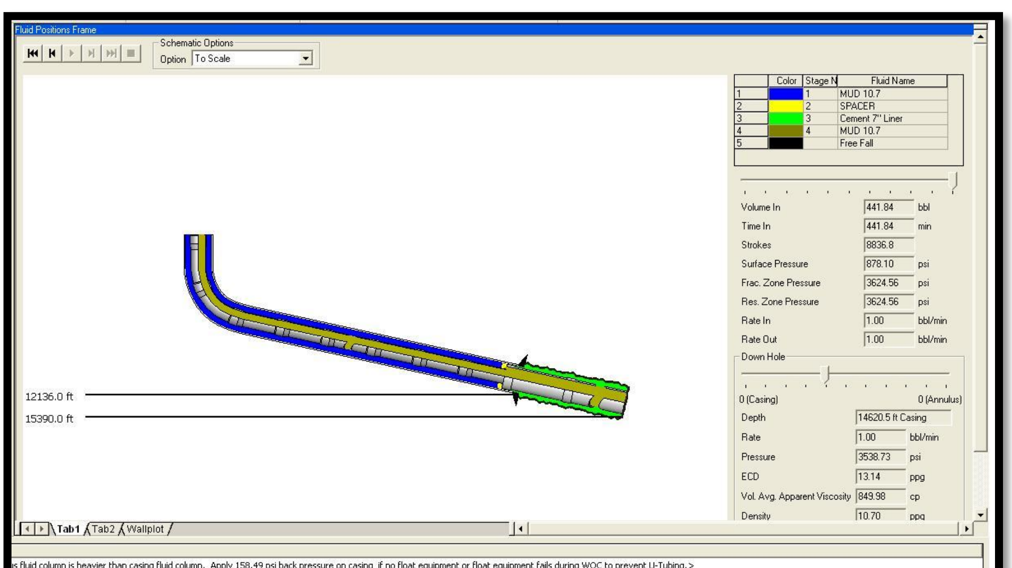
	Type	Fluid	New Stage?	Stage No	Placement Method	Rate (bbl/min)	**Stroke Rate (spm)	Duration (min)	Volume (bbl)	**Strokes	Top of Fluid (Measured Depth) (ft)	Length (ft)	Bulk Cement (94lb sacks)
1	Drilling Fld (Mud)	10.7 Drilling mud, 10.70 ppg	☑	1	Volume	2.50	50.00	0.00	0.00	0.0		11440.0	
2	Spacer/Flush	SPACER, 11.00 ppg	☑	2	Top of Fluid	2.50	50.00	3.45	8.62	172.4	11440.0	200.0	
3	Cement	Cement 7" Liner, 14.50 ppg	☑	3	Top of Fluid	2.50	50.00	34.48	86.19	1723.9	11640.0	3750.0	320.49
4	Top Plug*		☑										
5	Mud	10.7 Drilling mud, 10.70 ppg	☑	4	Volume	2.50	50.00	128.52	321.31	6426.2	0.0	15390.0	
6			☐										

A modified downhole pressure profile (*Figure 29*) can be now obtained:



As with the previous 9 5/8" casing cementing, lowering the flowrate caused the ECD value to decrease and be less than formation fracture gradient during cement and other fluids' pumping.

The next figure represent the fluid positions frame (*Figure 30*) after the animation of how the fluids move inside the 7" liner and out to the annulus and their final respective positions after the cement reaches its designated location:



4.2 Excel Macros

When I found myself repeatedly performing the same actions or tasks in my excel spreadsheet and the manual calculations, it was time for me to create a macro using Visual Basic module of Microsoft Excel. A macro is a recording of each command and action you perform to complete a task. Then, whenever you need to carry out that task in your spreadsheets, you just run the macro instead in Microsoft Excel. Macros can be activate by a couple of keystrokes or by a worksheet button so they are easy to execute, and, provided they were recorded correctly, they will always carry out the same steps in the same order with no chance for operator error.

4.2.1 Start up

For the manual calculation part which has many parameters depending on each other that I indicated in methodology part of this report, I wrote an Excel Macro code which includes all the original steps and considerations while calculating the ECD and pressure losses during the cement pumping.

Firstly the macro was written in a way so it includes all the necessary default and constant data like the tubular sizes and properties, casing seat depths and the fluid tops that such as spacer, drilling mud, lead and tail cement inside the wellbore after and during the cementing job.

The coding of a macro enables the user to input the fluid properties which can directly be changed on a rig and simulate it using the program. The program will give the average density, yield point, plastic viscosity values and last but not least the EMW (equivalent mud weight).

The average density is calculated by volume fraction that the fluid will occupy in the annulus of the wellbore from TD until the surface, on the other hands the EMW is calculated by height fractions and takes in account only the length in TVD that the fluid will occupy in the annulus., thus giving us the indication and the ways of measuring the pressure at TD of cemented section in a static condition.

The macro was coded in a way that the user can input the flowrate values in gallons per minute (GPM) for each section and observe from the table and the plot how the ECD at TD changes with changing the flowrate. Various steps, parameters, considerations and comparisons were taken into account while writing the code so to give the most right value of pressure losses and ECD value. And finally the program enables the user to see the flow regime in different parts of the wellbore and how it changes with the flowrate and changing the fluid parameters. The final touch was done by comparing the ECD and fracture gradient at TD (casing shoe = weakest point) and giving a user the indication of "normal" condition, when the ECD is less than fracture gradient, and the "decrease flowrate" condition where the program alerts and advices the user to decrease the flowrate and that ECD is higher than formation gradient, which can lead to the damage of the well and overall cementing and drilling operation.

4.2.2 Input data

The first step was inputting tubular data and properties in an Excel spreadsheet:

Tubular Data:			
13 3/8" Casing		7" Liner	
Type, grade	68 ppf, N-80, BTC	Type, grade	29 ppf, L-80, NV
OD, in	13,375	OD, in	7
ID, in	12,415	ID, in	6,18
OH, in	17,5	OH, in	8,50
Annular Capacity (OH), bbl/ft	0,12	Annular Capacity (OH), bbl/ft	0,0226
Casing Capacity, bbl/ft	0.1498	Casing Capacity, bbl/ft	0,0372
Annular Capacity (CSG), bbl/ft	0,34	Annular Capacity (CSG), bbl/ft	0,0256
	0,7		
9 5/8" Casing			
Type, grade	47 ppf, N-80, VT	5" DP	
OD, in	9,625	Type, grade	19,50 ppf, G, P
ID, in	8,68	OD, in	5
OH, in	12,25	ID, in	4,276
Annular Capacity (OH), bbl/ft	0,0558	OH, in (previous casing ID)	8,681
Casing Capacity, bbl/ft	0,07323	Annular Capacity (DPxCSG), bbl/ft	0,0489
Annular Capacity (CSG), bbl/ft	0,05976	DP Capacity, bbl/ft	0,02429

Table 8. Tubular data and properties

Second step was to input the cementing data which included all the information on fluid tops, volumes, heights and lengths (MD and TVD). Those volumes and heights will be used to determine the average densities and EMWs in three cemented sections later on.

Cementing Data						
	Last casing shoe 24" casing (MD), ft	574				
	Last 24" casing ID, in	22				
	Open hole Diameter, in	17,5				
13 3/8" section		Top of fluid (MD), ft	Top of fluid (TVD), ft	Length in Annulus (ft)	Vertical height (ft)	Volume occupied, bbl
	Drilling Mud	0	0	0	0	0
	Spacer	200	200	200	200	68,0
	Lead Cement	4420	3005	4220	2805	603,1
	Tail Cement	4920	3116	500	111	61,9
	Casing shoe (MD), ft	4920				
	Open hole Diameter, in	12,25				
9 5/8" section		Top of fluid (MD), ft	Top of fluid (TVD), ft	Length in Annulus (ft)	Vertical height (ft)	Volume occupied, bbl
	Drilling Mud	4220	2960	4220	2960	34,3
	Spacer	4420	3005	200	45	12,0
	Lead Cement	11600	4520	7180	1515	432,5
	Tail Cement	12136	4653	536	133	29,9
	Casing shoe (MD), ft	12136				
	Open hole Diameter, in	8,5				
7" section		Top of fluid (MD), ft	Top of fluid (TVD), ft	Length in Annulus (ft)	Vertical height (ft)	Volume occupied, bbl
	Drilling Mud	11440	4507	11440	4507	559,4
	Spacer	11640	4548	200	41	9,8
	Single Slurry Cement	15390	5350	3750	802	86,3
	Casing shoe (MD), ft	15390				

Table 9. Cementing data

The previous two tables are constant and cannot be changed for the wellbore we are cementing and for cementing operations as they are already preplanned and it is impossible to change them during cementing.

The next input table (*Table 10*) will enable the users to key in the fluid properties such as density, yield point, plastic viscosity and yield for cement case. The initial data given here is real field data that was used in OptiCem as well:

INPUT					
	Fluid Properties				
13 3/8" section		Density (ppg)	YP (lbf/100ft2)	PV (cp)	Yield (ft3/sk)
	Drilling Mud	10	22	20	-
	Spacer	10,5	12	28	-
	Lead Cement	12	10	60	2,14
	Tail Cement	15	25	100	1,19
9 5/8" section		Density (ppg)	YP (lbf/100ft2)	PV (cp)	Yield (ft3/sk)
	Drilling Mud	10,2	20	22	-
	Spacer	10,5	13	30	-
	Lead Cement	12,3	12	62	2,15
	Tail Cement	14	17	95	1,51
7" section		Density (ppg)	YP (lbf/100ft2)	PV (cp)	Yield (ft3/sk)
	Drilling Mud	10,7	18	25	-
	Spacer	11	13	30	-
	Single Slurry	14,5	17	95	1,51

The next input table for the user is the simplest one and the most important – flowrates for each section cementing. Here are the values for critical flowrates in which the ECD is totally equal to fracture gradient with kick margin, and the maximum flowrate that can be attained in each cemented section:

HYDRAULICS	
Casing String	Flow Rate, gpm
13 3/8" section	740
9 5/8" section	492
7" section	166

Table 11. Flowrate input

4.2.3 Output Data

After inputting the fluid data in the dedicated table it uses the preset data from the cementing data table and uses both data to calculate the average values of the density, yield point and plastic viscosity. The averaged values are given in next table (*Table 12*) and the data is refreshed every time you press the button "Calculate":

Average Fluid Properties		Output		
Average Density	Density (ppg)	YP (lbf/100ft2)	PV (cp)	EMW (ppg)
13 3/8" section	12,11	17,25	52,00	12,01
9 5/8" section	12,22	15,50	52,25	11,00
7" section	11,20	16,00	50,00	11,27

CALCULATE

Next table is coded in a way that it calculates the Hedstrom number and Reynolds number by calculating the equivalent viscosities and velocities in background. The table is enabled by the "Graph" buttons, and by pressing them the user is transferred to the Hedstrom plot, where you can find out the critical Reynolds number and input it in the next column. That value will then be compared with Reynolds number and give us the type of flow regime (turbulent, laminar). The flow regime indicates the fluid behavior in the wellbore during pumping:

Hydraulics

13 3/8" section	Hedstrom Number	Reynolds number	PRESS	Critical Reynolds	Flow Regime
inside casing	440729,28	2475,40	GRAPH	12000	Laminar
casing X OH	32480,42	444,71		4750	Laminar
casing X casing	142001,16	97,61		7500	Laminar

9 5/8" section	Hedstrom Number	Reynolds number		Critical Reynolds	Flow Regime
inside casing	193385,78	2885,49	GRAPH	8800	Laminar
casing X OH	11804,26	769,77		3500	Laminar
casing X casing	13334,87	712,18		3600	Laminar

7" section	Hedstrom Number	Reynolds number		Critical Reynolds	Flow Regime
inside drill pipe	48513,23	2094,38	GRAPH	5300	Laminar
inside liner	101466,76	1035,65		6950	Laminar
liner X OH	3985,31	407,13		2700	Laminar
liner X casing	5005,13	358,63		2900	Laminar
drillpipe X casing	24000,03	156,46		4400	Laminar

CALCULATE

Table 13. Output for flow regime

The next output will be the pressure loss calculation whose formulation depends on the flow regime that was found out earlier and the section that it takes place (inside string, annulus). This again is found out by pressing “Calculate” button, which will automatically finds out the ECD at TD, compares it with the fracture gradient at the same depth. The alert of safety of using the inputted flowrate will be highlighted in terms of “Normal” and “Decrease Flowrate” indicators in a set column:

	Pressure loss, psi					
	Inside Csg/Liner	Annular	Total	ECD	Comment	Fracture gradient, ppg
13 3/8" section	57,33	31,95	89,28	12,17	Normal	12,17
9 5/8" section	111,27	299,51	410,78	13,25	Normal	13,26
7" section	320,68	293,47	614,14	13,56	Normal	13,56

CALCULATE

Table 14. Output for pressure loss and ECD

In addition to all calculations, the plot of pore and fracture gradients vs. ECD is plotted automatically upon the pressing of "Calculate". This feature gives graphical interface to observe and compare the ECD and fracture gradient at TDs of three cemented sections:

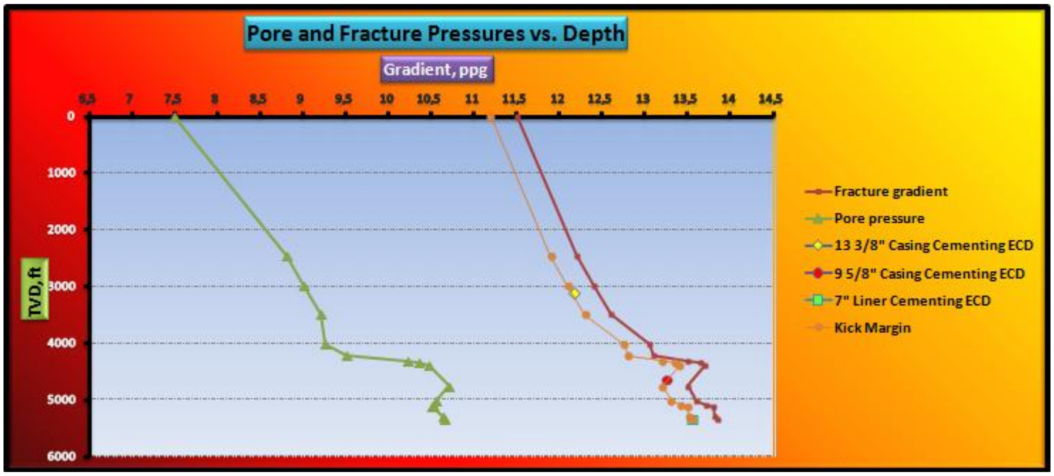


Figure 31. Pressure profile

4.3 Comparison of results

After finishing both, the OptiCem simulation and macro coding, I got the results from both of them. The main concern in both was to find out the critical flowrate using two ways with considering the ECD limitation which has to be less than fracture gradient at all times. This table gives us the comparison between critical flowrates obtained using OptiCem module of Landmark software of Halliburton and personally created macro for calculating the various fluid data:

Critical Flowrate, gpm		Percentage difference, %
OptiCem	Macros	
630	740	14,86%
420	492	14,63%
147	166	11,45%

Table 15. Comparion of Opticem and Macros critical flowrates

CHAPTER 5:

CONCLUSION AND RECOMENDATIONS

Cementing of a horizontal and ERD wells 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 that can prevent mud channeling and water channels are one of the most significant factors for a successful cement job. Through my research and studies I am trying to resolve those problems by proposing the suitable cement program. My first step towards the solution of the problem was going through number of literature reviews, which included numerous research papers, patents as well as laboratory and field works.

For my case I was working on the influence of the flowrate on the flow regime as for better hole cleaning as it was studied from my literature review. As it was written and studied by many engineers and researchers the turbulent flow regime of the cement pumped could be an appropriate way of removing the settled mud from the lower part of the annulus. Definitely for my studies, works and calculation I used cement with zero free water content, for avoiding the water channeling in the upper part of the annulus as was concluded and suggested by many papers I studied for my literature review.

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 my FYP I am more focused on working with the flowrate changes, and it is important factor as we could see from the 9 5/8" casing and 7" liner cementing modified jobs, where ONLY flowrate decreasing led to ECD to drop to appropriate levels without exceeding the fracture gradient, unlike the 13 3/8" casing cementing where I changed and played with many factors that is not much applicable in cementing and overall drilling jobs.

By decreasing the flowrate in software I am making sure that the ECD will not exceed the fracture gradient, but the main objective of my project is to avoid mud channeling in the bottom part of the annulus and casing by ensuring the turbulence flow regime of the pumped cement. Thus the appropriate velocity should be reached in the cemented zones, and meanwhile there must be some minimum flowrate when the flow regime turns from laminar to turbulent mode. This part of my project was done manually and by using personally created Excel Macros spreadsheet, because there is a **limitation of the OptiCem module** that doesn't enable us to observe or check the flow regime of the pumped fluids during cementing job.

Nevertheless it can be observed in Excel Macros program that was coded manually. The initial tubular and cementing data with the same fluid tops and properties that were used on OptiCem cementing simulation were used in macros as well for precise and accurate comparison purposes later on. The critical flowrates results obtained from macros were 11-14% more than the critical flowrates obtained from OptiCem. The reason for the difference is probably because the OptiCem module uses more sophisticated and empirical formulation and ways of obtaining the results. What is moe, in macros I found the average plastic viscosities and yield point by arithmetically averaging method, Opticem probably uses different ways of averaging those parameters. In addition to that OptiCem module also considers the gradual temperature increasing as we go deeper to the wellbore that directly can influence the properties of the cement slurry. One more explanation to the difference in critical flowrates can be estimated in terms of thickening time of the cement. OptiCem most likely to consider the thickening time of the cement and the way it influences the cement property as we are pumping it to the downhole, which directly changes the cement hydraulics data, results and behavior.

The flow regime for all the cases and locations were laminar as indicated by program. By multiple trials of changing the fluid properties and flowrates, the turbulence flow regime could not be attained without breaking the formation which is caused by the high ECD values. From here we can conclude that for the given data and wellbore with the same tubular and depth values, the turbulence cannot be obtained by simulating the fluid properties as well as flowrate changes. That gives us the information that for avoiding the mud channeling in lower zones of the annulus and casing, changing the flowrate only to reach the desired fluid regime is not enough and usually is highly dangerous because it directly and drastically influences the ECD value. Thus the other ways, methods and precautions should be studied and analyzed for avoiding the mud channeling during the cementing job.

The recommendations for preventing the problems like mud and water channeling were given in the studied papers and researches studied by me. For the water channeling case the only solution from the studies found was to use cement slurry with minimized to zero free water content, which I did in my calculations and simulations.

In order to make the cementing procedures easier and avoid mud channeling problems, the proper hole cleaning should be made by the mud itself in the first order. The fluid rheology should be suitable enough in order to keep the particles in suspension and avoid solid settling in the lower part of the annulus, which eventually lead to a creation of mud channeling. The other recommendation was to rotate the pipe during circulation of the mud, as that motion breaks the gel of a mud, when the solids are already precipitated and following by the appropriate flow regime those set of solids could be removed. All of these are part of drilling mud and hole cleaning program. From here we can make conclusion that, as to avoid problems in cementing jobs, right previous steps should be planned and executed, because all the drilling jobs and procedures are directly depending on the success of the previous works *(ex. Drilling ➔ casing run ➔ hole cleaning ➔ cementing ➔ perforating ➔ production…etc)*

REFERENCES:

1) http://www.onepetro.org/mslib/app/search.do

(A unique web-library of technical documents and journal articles serving the E&P industry)

2) "Drilling design and implementation for extended reach and complex wells" *M.G. Mims; A.N. Krepp; H.A. Williamsd, 1999, Second edition*

3) "Extended Reach Drilling Guidelines" *The British Petroleum Company p.l.c., 1996*

4) "Comprehensive Extended Reach Drilling" E-Tech International/Powers Engineering, August 17, 2005

5) "Well engineering and construction" *Hussain Rabia, 2002*

6) "Drilling fluid engineering" *Pal Skalle, 2010*

7) "Drilling Mud and Cement Slurry Rheology Manual" *by Technip, French Oil and Gas Industry Assn., 1982*

APPENDIX

Excel Macros coding:

Sub one()

Sheets("yes").Select

'Average density

Cells(4, 10) = Cells(7, 4).Value * Cells(109, 8).Value / (Cells(109, 8).Value + Cells(110, 8).Value + Cells(111, 8).Value) + Cells(8, 4).Value * Cells(110, 8).Value / (Cells(109, 8).Value + Cells(110, 8).Value + Cells(111, 8).Value) + Cells(9, 4).Value * Cells(111, 8).Value / (Cells(109, 8).Value + Cells(110, 8).Value + Cells(111, 8).Value)

Cells(5, 10) = Cells(13, 4).Value * Cells(116, 8).Value / (Cells(116, 8).Value + Cells(117, 8).Value + Cells(118, 8).Value + Cells(119, 8).Value) + Cells(14, 4).Value * Cells(117, 8).Value / (Cells(116, 8).Value + Cells(117, 8).Value + Cells(118, 8).Value + Cells(119, 8).Value) + Cells(15, 4).Value * Cells(118, 8).Value / (Cells(116, 8).Value + Cells(117, 8).Value + Cells(118, 8).Value + Cells(119, 8).Value) + Cells(16, 4).Value * Cells(119, 8).Value / (Cells(116, 8).Value + Cells(117, 8).Value + Cells(118, 8).Value + Cells(119, 8).Value)

Cells(6, 10) = Cells(20, 4).Value * Cells(124, 8).Value / (Cells(124, 8).Value + Cells(125, 8).Value + Cells(126, 8).Value) + Cells(21, 4).Value * Cells(125, 8).Value / (Cells(124, 8).Value + Cells(125, 8).Value + Cells(126, 8).Value) + Cells(22, 4).Value * Cells(126, 8).Value / (Cells(124, 8).Value + Cells(125, 8).Value + Cells(126, 8).Value)

'EMW

Cells(4, 13) = Cells(7, 4).Value * Cells(109, 7).Value / (Cells(109, 7).Value + Cells(110, 7).Value + Cells(111, 7).Value) + Cells(8, 4).Value * Cells(110, 7).Value / (Cells(109, 7).Value + Cells(110, 7).Value + Cells(111, 7).Value) + Cells(9, 4).Value * Cells(111, 7).Value / (Cells(109, 7).Value + Cells(110, 7).Value + Cells(111, 7).Value)

Cells(5, 13) = Cells(13, 4).Value * Cells(116, 7).Value / (Cells(116, 7).Value + Cells(117, 7).Value + Cells(118, 7).Value + Cells(119, 7).Value) + Cells(14, 4).Value * Cells(117, 7).Value / (Cells(116, 7).Value + Cells(117, 7).Value + Cells(118, 7).Value + Cells(119, 7).Value) + Cells(15, 4).Value * Cells(118, 7).Value / (Cells(116, 7).Value + Cells(117, 7).Value + Cells(118, 7).Value + Cells(119, 7).Value) + Cells(16, 4).Value * Cells(119, 7).Value / (Cells(116, 7).Value + Cells(117, 7).Value + Cells(118, 7).Value + Cells(119, 7).Value)

Cells(6, 13) = Cells(20, 4).Value * Cells(124, 7).Value / (Cells(124, 7).Value + Cells(125, 7).Value + Cells(126, 7).Value) + Cells(21, 4).Value * Cells(125, 7).Value / (Cells(124, 7).Value + Cells(125, 7).Value + Cells(126, 7).Value) + Cells(22, 4).Value * Cells(126, 7).Value / (Cells(124, 7).Value + Cells(125, 7).Value + Cells(126, 7).Value)

'Yield point

Cells(4, 11) = (Cells(6, 5).Value + Cells(7, 5).Value + Cells(8, 5).Value + Cells(9, 5).Value) / 4

Cells(5, 11) = (Cells(13, 5).Value + Cells(14, 5).Value + Cells(15, 5).Value + Cells(16, 5).Value) / 4

Cells(6, 11) = (Cells(20, 5).Value + Cells(21, 5).Value + Cells(22, 5).Value) / 3

'Plastic viscosity

Cells(4, 12) = (Cells(6, 6).Value + Cells(7, 6).Value + Cells(8, 6).Value + Cells(9, 6).Value) / 4

Cells(5, 12) = (Cells(13, 6).Value + Cells(14, 6).Value + Cells(15, 6).Value + Cells(16, 6).Value) / 4

Cells(6, 12) = (Cells(20, 6).Value + Cells(21, 6).Value + Cells(22, 6).Value) / 3

End Sub

Sub hydro()

Sheets("yes").Select

'hedstrom 13

Cells(13, 10) = (37000 * Cells(4, 10).Value * Cells(4, 11).Value * Cells(64, 3).Value * Cells(64, 3).Value) / (Cells(4, 12).Value * Cells(4, 12).Value)

Cells(14, 10) = (24700 * Cells(4, 10).Value * Cells(4, 11).Value * (Cells(65, 3).Value - Cells(63, 3).Value) * (Cells(65, 3).Value - Cells(63, 3).Value)) / (Cells(4, 12).Value * Cells(4, 12).Value)

Cells(15, 10) = (24700 * Cells(4, 10).Value * Cells(4, 11).Value * (Cells(102, 4).Value - Cells(63, 3).Value) * (Cells(102, 4).Value - Cells(63, 3).Value)) / (Cells(4, 12).Value * Cells(4, 12).Value)

'hedstrom 9

Cells(18, 10) = (37000 * Cells(5, 10).Value * Cells(5, 11).Value * Cells(73, 3).Value * Cells(73, 3).Value) / (Cells(5, 12).Value * Cells(5, 12).Value)

Cells(19, 10) = (24700 * Cells(5, 10).Value * Cells(5, 11).Value * (Cells(74, 3).Value - Cells(72, 3).Value) * (Cells(74, 3).Value - Cells(72, 3).Value)) / (Cells(5, 12).Value * Cells(5, 12).Value)

Cells(20, 10) = (24700 * Cells(5, 10).Value * Cells(5, 11).Value * (Cells(64, 3).Value - Cells(72, 3).Value) * (Cells(64, 3).Value - Cells(72, 3).Value)) / (Cells(5, 12).Value * Cells(5, 12).Value)

'hedstrom 7

Cells(23, 10) = (37000 * Cells(6, 10).Value * Cells(6, 11).Value * Cells(92, 3).Value * Cells(92, 3).Value) / (Cells(6, 12).Value * Cells(6, 12).Value)

Cells(24, 10) = (37000 * Cells(6, 10).Value * Cells(6, 11).Value * Cells(82, 3).Value * Cells(82, 3).Value) / (Cells(6, 12).Value * Cells(6, 12).Value)

Cells(25, 10) = (24700 * Cells(6, 10).Value * Cells(6, 11).Value * (Cells(83, 3).Value - Cells(81, 3).Value) * (Cells(83, 3).Value - Cells(81, 3).Value)) / (Cells(6, 12).Value * Cells(6, 12).Value)

Cells(26, 10) = (24700 * Cells(6, 10).Value * Cells(6, 11).Value * (Cells(73, 3).Value - Cells(81, 3).Value) * (Cells(73, 3).Value - Cells(81, 3).Value)) / (Cells(6, 12).Value * Cells(6, 12).Value)

Cells(27, 10) = (24700 * Cells(6, 10).Value * Cells(6, 11).Value * (Cells(73, 3).Value - Cells(91, 3).Value) * (Cells(73, 3).Value - Cells(91, 3).Value)) / (Cells(6, 12).Value * Cells(6, 12).Value)

'reynolds number 13

Cells(13, 11) = 928 * Cells(4, 10).Value * Cells(29, 3).Value / (Cells(64, 3).Value * 2.448 * (Cells(4, 12).Value + 6.66 * Cells(4, 11).Value * Cells(64, 3).Value * Cells(64, 3).Value * 2.448 / Cells(29, 3).Value))

Cells(14, 11) = 757 * Cells(4, 10).Value * Cells(29, 3).Value * (Cells(65, 3).Value - Cells(63, 3).Value) / ((Cells(65, 3).Value * Cells(65, 3).Value - Cells(63, 3).Value * Cells(63, 3).Value) * 2.448 * (Cells(4, 12).Value + 5 * Cells(4, 11).Value * (Cells(65, 3).Value * Cells(65, 3).Value - Cells(63, 3).Value * Cells(63, 3).Value) * (Cells(65, 3).Value - Cells(63, 3).Value) * 2.448 / Cells(29, 3).Value))

Cells(15, 11) = 757 * Cells(4, 10).Value * Cells(29, 3).Value * (Cells(102, 4).Value - Cells(63, 3).Value) / ((Cells(102, 4).Value * Cells(102, 4).Value - Cells(63, 3).Value * Cells(63, 3).Value) * 2.448 * (Cells(4, 12).Value + 5 * Cells(4, 11).Value * (Cells(102, 4).Value * Cells(102, 4).Value - Cells(63, 3).Value * Cells(63, 3).Value) * (Cells(102, 4).Value - Cells(63, 3).Value) * 2.448 / Cells(29, 3).Value))

'reynolds number 9

Cells(18, 11) = (928 * Cells(5, 10).Value * Cells(30, 3).Value) / (Cells(73, 3).Value * 2.448 * (Cells(5, 12).Value + (6.66 * Cells(5, 11).Value * Cells(73, 3).Value * Cells(73, 3).Value * 2.448) / Cells(30, 3).Value))

Cells(19, 11) = 757 * Cells(5, 10).Value * Cells(30, 3).Value * (Cells(74, 3).Value - Cells(72, 3).Value) / ((Cells(74, 3).Value * Cells(74, 3).Value - Cells(72, 3).Value * Cells(72, 3).Value) * 2.448 * (Cells(5, 12).Value + 5 * Cells(5, 11).Value * (Cells(74, 3).Value * Cells(74, 3).Value - Cells(72, 3).Value * Cells(72, 3).Value) * (Cells(74, 3).Value - Cells(72, 3).Value) * 2.448 / Cells(30, 3).Value))

Cells(20, 11) = 757 * Cells(5, 10).Value * Cells(30, 3).Value * (Cells(64, 3).Value - Cells(72, 3).Value) / ((Cells(64, 3).Value * Cells(64, 3).Value - Cells(72, 3).Value * Cells(72, 3).Value) * 2.448 * (Cells(5, 12).Value + 5 * Cells(5, 11).Value * (Cells(64, 3).Value * Cells(64, 3).Value - Cells(72, 3).Value * Cells(72, 3).Value) * (Cells(64, 3).Value - Cells(72, 3).Value) * 2.448 / Cells(30, 3).Value))

'reynolds number 7

Cells(23, 11) = (928 * Cells(6, 10).Value * Cells(31, 3).Value) / (Cells(92, 3).Value * 2.448 * (Cells(6, 12).Value + (6.66 * Cells(6, 11).Value * Cells(92, 3).Value * Cells(92, 3).Value * 2.448) / Cells(31, 3).Value))

Cells(24, 11) = (928 * Cells(6, 10).Value * Cells(31, 3).Value) / (Cells(82, 3).Value * 2.448 * (Cells(6, 12).Value + (6.66 * Cells(6, 11).Value * Cells(82, 3).Value * Cells(82, 3).Value * 2.448) / Cells(31, 3).Value))

Cells(25, 11) = 757 * Cells(6, 10).Value * Cells(31, 3).Value * (Cells(83, 3).Value - Cells(81, 3).Value) / ((Cells(83, 3).Value * Cells(83, 3).Value - Cells(81, 3).Value * Cells(81, 3).Value) * 2.448 * (Cells(6, 12).Value + 5 * Cells(6, 11).Value * (Cells(83, 3).Value * Cells(83, 3).Value - Cells(81, 3).Value * Cells(81, 3).Value) * (Cells(83, 3).Value - Cells(81, 3).Value) * 2.448 / Cells(31, 3).Value))

Cells(26, 11) = 757 * Cells(6, 10).Value * Cells(31, 3).Value * (Cells(73, 3).Value - Cells(81, 3).Value) / ((Cells(73, 3).Value * Cells(73, 3).Value - Cells(81, 3).Value * Cells(81, 3).Value) * 2.448 * (Cells(6, 12).Value + 5 * Cells(6, 11).Value * (Cells(73, 3).Value * Cells(73, 3).Value - Cells(81, 3).Value * Cells(81, 3).Value) * (Cells(73, 3).Value - Cells(81, 3).Value) * 2.448 / Cells(31, 3).Value))

Cells(27, 11) = 757 * Cells(6, 10).Value * Cells(31, 3).Value * (Cells(73, 3).Value - Cells(91, 3).Value) / ((Cells(73, 3).Value * Cells(73, 3).Value - Cells(91, 3).Value * Cells(91, 3).Value) * 2.448 * (Cells(6, 12).Value + 5 * Cells(6, 11).Value * (Cells(73, 3).Value * Cells(73, 3).Value - Cells(91, 3).Value * Cells(91, 3).Value) * (Cells(73, 3).Value - Cells(91, 3).Value) * 2.448 / Cells(31, 3).Value))

'Flow regime 13

```
If Cells(13, 11).Value < Cells(13, 13).Value Then

Cells(13, 14) = "Laminar"

Else

Cells(13, 14) = "Turbulent"

End If

If Cells(14, 11).Value < Cells(14, 13).Value Then

Cells(14, 14) = "Laminar"

Else

Cells(14, 14) = "Turbulent"

End If

If Cells(15, 11).Value < Cells(15, 13).Value Then

Cells(15, 14) = "Laminar"

Else

Cells(15, 14) = "Turbulent"

End If
```

'Flow regime 9

```
If Cells(18, 11).Value < Cells(18, 13).Value Then

Cells(18, 14) = "Laminar"

Else

Cells(18, 14) = "Turbulent"

End If


If Cells(19, 11).Value < Cells(19, 13).Value Then
```

```
Cells(19, 14) = "Laminar"
Else
Cells(19, 14) = "Turbulent"
End If
If Cells(20, 11).Value < Cells(20, 13).Value Then
Cells(20, 14) = "Laminar"
Else
Cells(20, 14) = "Turbulent"
End If
'Flow regime 7
If Cells(23, 11).Value < Cells(23, 13).Value Then
Cells(23, 14) = "Laminar"
Else
Cells(23, 14) = "Turbulent"
End If
If Cells(24, 11).Value < Cells(24, 13).Value Then
Cells(24, 14) = "Laminar"
Else
Cells(24, 14) = "Turbulent"
End If
If Cells(25, 11).Value < Cells(25, 13).Value Then
Cells(25, 14) = "Laminar"
Else
Cells(25, 14) = "Turbulent"
```

```
End If

If Cells(26, 11).Value < Cells(26, 13).Value Then

Cells(26, 14) = "Laminar"

Else

Cells(26, 14) = "Turbulent"

End If

If Cells(27, 11).Value < Cells(27, 13).Value Then

Cells(27, 14) = "Laminar"

Else

Cells(27, 14) = "Turbulent"

End If

End Sub

Sub heds()

Sheets("Hedstrom").Select

End Sub

Sub ploss()

' 13 casing inside casing

If Cells(13, 11).Value < Cells(13, 13).Value Then

Cells(13, 16) = Cells(112, 4).Value * (Cells(4, 12).Value * Cells(29, 3).Value / (1500 * 2.448 * Cells(64, 3).Value * Cells(64, 3).Value * Cells(64, 3).Value) + Cells(4, 11).Value / (225 * Cells(64, 3).Value))


Else

Cells(13, 16) = Cells(112, 4).Value * (0.0791 * Cells(4, 10).Value * (Cells(29, 3).Value / 2.448 / Cells(64, 3).Value / Cells(64, 3).Value) * (Cells(29, 3).Value / 2.448 / Cells(64, 3).Value / Cells(64, 3).Value) / ((Cells(13, 11).Value) ^ 0.25 * 25.8 * Cells(64, 3).Value))
```

End If

' 13 casing inside casing x OH

If Cells(14, 11).Value < Cells(14, 13).Value Then

Cells(14, 16) = (Cells(112, 4).Value - Cells(101, 4).Value) * (Cells(4, 12).Value * Cells(132, 3).Value / 1000 / (Cells(65, 3).Value - Cells(63, 3).Value) ^ 2) + Cells(4, 11).Value / 200 / (Cells(65, 3).Value - Cells(63, 3).Value)

Else

Cells(14, 16) = (Cells(112, 4).Value - Cells(101, 4).Value) * (0.0791 * Cells(4, 10).Value * (Cells(132, 3).Value) ^ 2) / ((Cells(14, 11).Value) ^ 0.25 * 21.1 * (Cells(65, 3).Value - Cells(63, 3).Value))

End If

' 13 casing inside casing x casing

If Cells(15, 11).Value < Cells(15, 13).Value Then

Cells(15, 16) = Cells(101, 4).Value * (Cells(4, 12).Value * Cells(133, 3).Value / 1000 / (Cells(102, 4).Value - Cells(63, 3).Value) ^ 2) + Cells(4, 11).Value / 200 / (Cells(102, 4).Value - Cells(63, 3).Value)

Else

Cells(15, 16) = Cells(101, 4).Value * (0.0791 * Cells(4, 10).Value * (Cells(133, 3).Value) ^ 2) / ((Cells(15, 11).Value) ^ 0.25 * 21.1 * (Cells(102, 4).Value - Cells(63, 3).Value))

End If

' 9 casing inside casing

If Cells(18, 11).Value < Cells(18, 13).Value Then

Cells(18, 16) = Cells(120, 4).Value * ((Cells(5, 12).Value * Cells(136, 3).Value) / (1500 * (Cells(73, 3).Value) ^ 2) + Cells(5, 11).Value / (225 * Cells(73, 3).Value))

Else

Cells(18, 16) = Cells(120, 4).Value * (0.0791 / (Cells(18, 11).Value) ^ 0.25) * Cells(5, 10).Value * (Cells(136, 3).Value) ^ 2 / (25.8 * Cells(73, 3).Value)

End If

'9 casing x OH

If Cells(19, 11).Value < Cells(19, 13).Value Then

Cells(19, 16) = (Cells(120, 4).Value - Cells(112, 4).Value) * (Cells(5, 12).Value * Cells(137, 3).Value / 1000 / (Cells(74, 3).Value - Cells(72, 3).Value) ^ 2) + Cells(5, 11).Value / 200 / (Cells(74, 3).Value - Cells(72, 3).Value)

Else

Cells(19, 16) = (Cells(120, 4).Value - Cells(112, 4).Value) * (0.0791 * Cells(5, 10).Value * (Cells(137, 3).Value) ^ 2) / ((Cells(19, 11).Value) ^ 0.25 * 21.1 * (Cells(74, 3).Value - Cells(72, 3).Value))

End If

'9 casing X casing

If Cells(20, 11).Value < Cells(20, 13).Value Then

Cells(20, 16) = Cells(112, 4).Value * (Cells(5, 12).Value * Cells(138, 3).Value / 1000 / (Cells(64, 3).Value - Cells(72, 3).Value) ^ 2) + Cells(5, 11).Value / 200 / (Cells(64, 3).Value - Cells(72, 3).Value)

Else

Cells(20, 16) = Cells(112, 4).Value * (0.0791 * Cells(5, 10).Value * (Cells(138, 3).Value) ^ 2) / ((Cells(20, 11).Value) ^ 0.25 * 21.1 * (Cells(64, 3).Value - Cells(72, 3).Value))

End If

'7 inside drill pipe

If Cells(23, 11).Value < Cells(23, 13).Value Then

Cells(23, 16) = (Cells(127, 4).Value - Cells(128, 4).Value) * ((Cells(6, 12).Value * Cells(141, 3).Value) / (1500 * (Cells(92, 3).Value) ^ 2) + Cells(6, 11).Value / (225 * Cells(92, 3).Value))

Else

Cells(23, 16) = (Cells(127, 4).Value - Cells(128, 4).Value) * (0.0791 / (Cells(23, 11).Value) ^ 0.25) * Cells(6, 10).Value * (Cells(141, 3).Value) ^ 2 / (25.8 * Cells(92, 3).Value)

End If

'7 inside liner

If Cells(24, 11).Value < Cells(24, 13).Value Then

Cells(24, 16) = Cells(128, 4).Value * ((Cells(6, 12).Value * Cells(142, 3).Value) / (1500 * (Cells(82, 3).Value) ^ 2) + Cells(6, 11).Value / (225 * Cells(82, 3).Value))

Else

Cells(24, 16) = Cells(128, 4).Value * (0.0791 / (Cells(24, 11).Value) ^ 0.25) * Cells(6, 10).Value * (Cells(142, 3).Value) ^ 2 / (25.8 * Cells(82, 3).Value)

End If

'7 liner X OH

If Cells(25, 11).Value < Cells(25, 13).Value Then

Cells(25, 16) = (Cells(127, 4).Value - Cells(120, 4).Value) * (Cells(6, 12).Value * Cells(143, 3).Value / 1000 / (Cells(83, 3).Value - Cells(81, 3).Value) ^ 2) + Cells(6, 11).Value / 200 / (Cells(83, 3).Value - Cells(81, 3).Value)

Else

Cells(25, 16) = (Cells(127, 4).Value - Cells(120, 4).Value) * (0.0791 * Cells(6, 10).Value * (Cells(143, 3).Value) ^ 2) / ((Cells(25, 11).Value) ^ 0.25 * 21.1 * (Cells(83, 3).Value - Cells(81, 3).Value))

End If

'7 liner X casing

If Cells(26, 11).Value < Cells(26, 13).Value Then

Cells(26, 16) = (Cells(128, 4).Value - (Cells(127, 4).Value - Cells(120, 4).Value)) * (Cells(6, 12).Value * Cells(144, 3).Value / 1000 / (Cells(73, 3).Value - Cells(81, 3).Value) ^ 2) + Cells(6, 11).Value / 200 / (Cells(73, 3).Value - Cells(81, 3).Value)

Else

Cells(26, 16) = (Cells(128, 4).Value - (Cells(127, 4).Value - Cells(120, 4).Value)) * (0.0791 * Cells(6, 10).Value * (Cells(144, 3).Value) ^ 2) / ((Cells(26, 11).Value) ^ 0.25 * 21.1 * (Cells(73, 3).Value - Cells(81, 3).Value))

End If

'7 drillpipe X casing

If Cells(27, 11).Value < Cells(27, 13).Value Then

Cells(27, 16) = (Cells(127, 4).Value - Cells(128, 4).Value) * (Cells(6, 12).Value * Cells(145, 3).Value / 1000 / (Cells(73, 3).Value - Cells(91, 3).Value) ^ 2) + Cells(6, 11).Value / 200 / (Cells(73, 3).Value - Cells(91, 3).Value)

Else

Cells(27, 16) = (Cells(127, 4).Value - Cells(128, 4).Value) * (0.0791 * Cells(6, 10).Value * (Cells(145, 3).Value) ^ 2) / ((Cells(27, 11).Value) ^ 0.25 * 21.1 * (Cells(73, 3).Value - Cells(91, 3).Value))

End If

'13 pressure loss

Cells(33, 10) = Cells(13, 16).Value

Cells(33, 11) = Cells(14, 16).Value + Cells(15, 16).Value

Cells(33, 12) = Cells(33, 10).Value + Cells(33, 11).Value

Cells(33, 13) = Cells(4, 13) + Cells(33, 17).Value + Cells(33, 11) / (0.052 * (Cells(109, 7).Value + Cells(110, 7).Value + Cells(111, 7).Value))

'9 pressure loss

Cells(34, 10) = Cells(18, 16).Value

Cells(34, 11) = Cells(19, 16).Value + Cells(20, 16).Value

Cells(34, 12) = Cells(34, 10).Value + Cells(34, 11).Value

Cells(34, 13) = Cells(34, 17).Value + Cells(5, 13) + Cells(34, 11) / (0.052 * (Cells(116, 7).Value + Cells(117, 7).Value + Cells(118, 7).Value + Cells(119, 7).Value))

'7 pressure loss

Cells(35, 10) = Cells(23, 16).Value + Cells(24, 16).Value

Cells(35, 11) = Cells(25, 16).Value + Cells(26, 16).Value + Cells(27, 16).Value

Cells(35, 12) = Cells(35, 10).Value + Cells(35, 11).Value

Cells(35, 13) = Cells(35, 17).Value + Cells(6, 13) + Cells(35, 11) / (0.052 * (Cells(124, 7).Value + Cells(125, 7).Value + Cells(126, 7).Value))

```
If Cells(33, 13).Value < Cells(33, 15).Value Then

Cells(33, 14) = "Normal"

Else

Cells(33, 14) = "Decrease Flowrate"

End If

If Cells(34, 13).Value < Cells(34, 15).Value Then

Cells(34, 14) = "Normal"

Else

Cells(34, 14) = "Decrease Flowrate"

End If

If Cells(35, 13).Value < Cells(35, 15).Value Then

Cells(35, 14) = "Normal"

Else

Cells(35, 14) = "Decrease Flowrate"

End If

End Sub
```