RHEOLOGICAL BEHAVIOR OF AN OBM SAMPLE OF THE GOM UNDER XHPHT CONDITIONS

A Thesis

by

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MASTER OF SCIENCE

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ABSTRACT

The scope of this research is to study the rheological behavior of an oil based mud (OBM) sample from the Mexican side of the Gulf of Mexico (GOM) under extreme conditions of High Pressure High Temperature (HPHT). In the coming years many HPHT wells are going to be drilled in this area of the GOM. Currently Mexican Oil and Gas industry is already open to international operators because the Mexican energy reform has been approved, so it is important to study the possible drilling fluids that will be used. These fluids can be within any of these 3 tiers of HPHT classification: HPHT, ultra (uHPHT) or extreme (xHPHT).

The sample was submitted to extreme HPHT conditions, by using the state-of-the-art Model 7600 HPHT Viscometer that is capable of measuring drilling fluid properties up to 40,000 psi and 600 °F. During the laboratory tests performance, it was noticed that erroneous results were obtained by several mechanical failures. It should be noted that the spare parts take a long time to arrive-around 3 weeks. One of the failures was that the pivot of the spring assembly got inside the device, so the bob was spinning nonstop. For this reason the readings of the dial went well beyond the allowed range; another mechanical failure was that the spring of the spring assembly was loose, which did not allow us to obtain a correct reading of shear stress at high pressures and low temperatures; also the baffle does not separate the pressurizing oil from the sample, mixing these two fluids and obviously affecting the properties of the sample. This was

noticed by running one test with baffle and another without it getting very similar results.

The rheological behavior of the sample showed that the viscosity is inversely proportional to temperature and directly proportional to pressure, noticing a failure point at 300 °F, because of sample degradation.

Moreover the rheogram´s curves obtained are quite similar to a second degree polynomial function, with R-squared values ranging from 0.95 to 0.99; hence an equation can be adjusted in the future by extrapolating different pressure and temperature values.

DEDICATION

This work is dedicated to my beautiful wife and two daughters.

ACKNOWLEDGEMENTS

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Thanks to my wife and my two daughters for their patience and love.

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CONTRIBUTORS AND FUNDING SOURCES

Contributors

This work was supervised by a thesis committee consisting of Professor Dr. Schubert [advisor] and Dr. Noynaert of the Department of Petroleum Engineering and Professor Dr. Medina-Cetina of the Department of Civil Engineering.

All work for the thesis was completed independently by the student.

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NOMENCLATURE

API	American Petroleum Institute
BHDF	Baker Hughes Drilling Fluids
BHP	Bottom Hole Pressure
BHT	Bottom Hole Temperature
CaCl	Calcium Chloride
$CaCO_3$	Calcium Carbonate
CMC	Carboxymethyl cellulose
cP	Centipoise
DEA	Danish Energy Agency
EBF	Emulsion Based Drilling Fluid
ECD	Equivalent Circulating Density
γ	Shear Rate
GOM	Gulf of Mexico
H_2S	Hydrogen Sulfide
HPHT	High Pressure High Temperature
HPWBM	High Performance Water Based Mud
HSE	Health, Safety and Environment
ISO	International Organization for Standardization
KCl	Potassium Chloride
LSRV	Low Shear Rate Viscosity

LWD	Logging While Drilling
μ_p	Plastic Viscosity
Mn_3O_4	Manganese Tetroxide
MPa	Mega Pascal
MPD	Managed Pressure Drilling
MSDS	Material Safety Data Sheet
MW	Mud Weight
MWCNT	Multiwall Carbon Nanotubes
MWD	Measurement While Drilling
NaCl	Sodium Chloride
NADF	Non-Aqueous Drilling Fluids
NETL	National Energy Technology Laboratory
nm	Nautical Miles
OBM	Oil Based Mud
OCS	Outer Continental Shelf
OWR	Oil Water Ratio
PA	Polyamide
PDC	Polycrystalline Diamond Compact
PHPA	Partially Hydrolyzed Polyacrylamide
ppb	Parts Per Billion
PPE	Personal Protective Equipment
ppg	Pounds Per Gallon

PV	Plastic Viscosity
PWD	Pressure While Drilling
ROP	Rate of Penetration
RPM	Revolutions Per Minute
SBM	Synthetic Based Mud
τ	Shear Stress
TSP	Thermally Stable Polycrystalline
TVD	True Vertical Depth
τ_y	Yield Point
uHPHT	Ultra High Pressure High Temperature
VES	Viscoelastic Surfactant
WBM	Water Based Mud
xHPHT	Extreme High Pressure High Temperature
YP	Yield Point

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CHAPTER I

INTRODUCTION

The term HPHT was first coined in the 1990 Cullen Report published in the aftermath of the Piper Alpha platform disaster. Generally used to describe wells of a hotter or higher pressure than most, HPHT wells have become increasingly commonplace in a world of dwindling conventional reserves.

As can be seen in Figure 1, a lot of yellow spots are displayed in the US side of deepwater GOM, and just a few in the Mexican side, hence there are a lot of opportunities to drill in the Mexican side of deepwater GOM, like the Perdido field, surely many of these wells will be HPHT, herein lays the importance of the development of this research, in order to understand the behavior of drilling fluids under HPHT conditions.

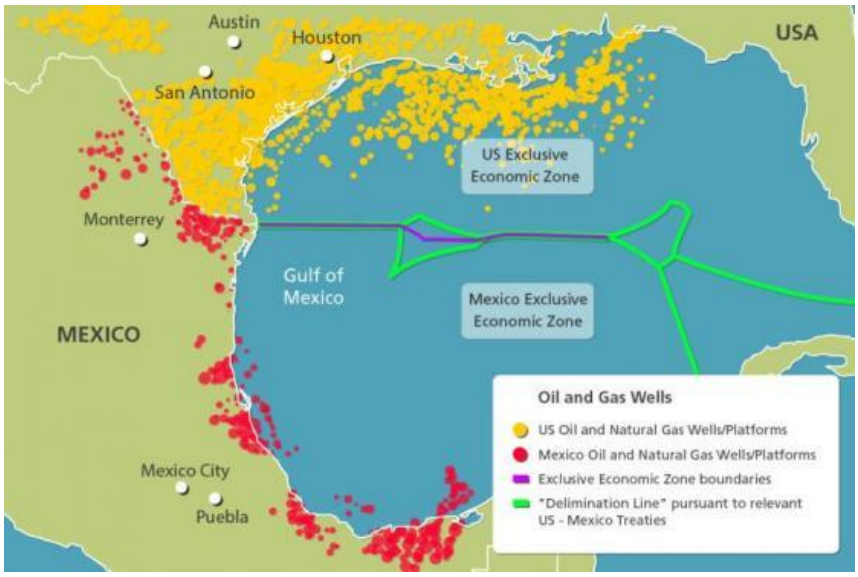

Figure 1 Mexico Oil and Gas Sector (Oil_&_Gas_360 2015)

CHAPTER II

LITERATURE REVIEW

2.1 HPHT Wells

In HPHT environments there are frequently narrow operational windows between pore and fracture pressure which requires drilling fluids designed to minimize Equivalent Circulating Density (ECD), (De Stefano, Stamatakis, and Young 2012).

2.1.1 Classification

HPHT wells are defined when the pressure exceeds 15,000 psi (103 MPa or 1,034 bar) and temperature is over 300 °F (149 °C). The existing classifications segment HPHT operations into three main tiers (Figure 2 and Figure 3).

Tier I make reference to wells with pressures from 10,000 to 20,000 psi and temperatures between 300 and 400 °F. Until now, many of the shale plays and deepwater HPHT operations are located in Tier I.

Tier II is named “Ultra” HPHT and pressure range is from 20,000 to 30,000 psi and temperatures from 400 to 500 °F. It includes many deep gas reservoirs in US and the GOM continental shelf.

Tier III refers to “extreme” HPHT wells, pressure range is from 30,000 to 40,000 psi and temperatures between 500 and 600 °F. This is the HPHT classification with most technology gaps.

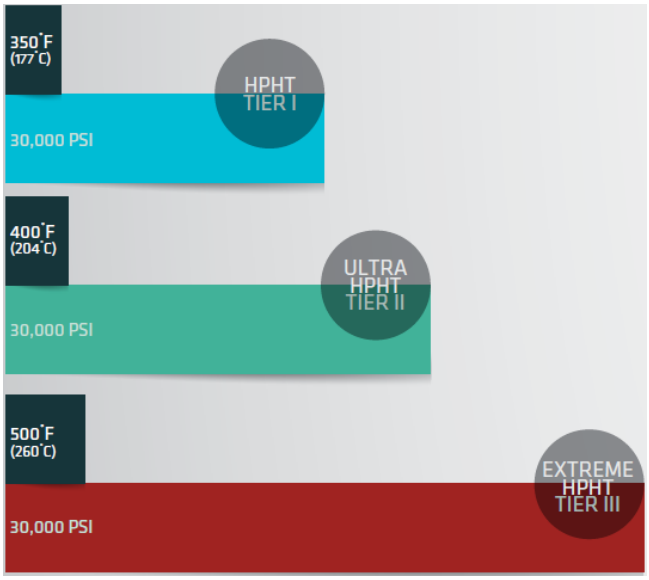

Figure 2 HPHT Wells are Classified into Three Tiers, Determined by Reservoir Temperatures and Pressures (Oil_and_gas_iQ 2013)

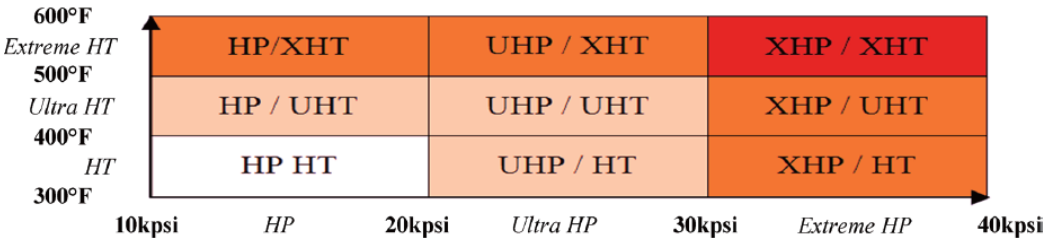

Figure 3 Matrix of HPHT Operation (Shadravan and Amani 2012)

Another classification was done by DeBruijn et al. 2008 (Figure 4):

HPHT wells start at 149 °C [300 °F] bottom hole temperature (BHT) or 69 MPa [10,000 psi] bottom hole pressure (BHP).

Ultra-HPHT wells surpassed the operational boundary of prevail electronics technology—greater than 204 °C [400 °F] or 138 MPa [20,000 psi].

The HPHT-hc classification describes the most severe environments—wells with temperatures greater than 260 °C [500 °F] and pressures greater than 241 MPa [35,000 psi]. “hc” stands for hors catégorie (beyond classification) is the steepest mountain-grade classification used by the cycling competition Tour de France.

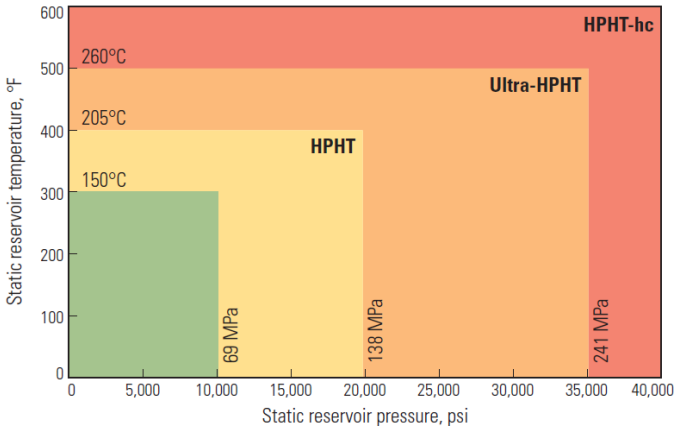

Figure 4 HPHT Tiers (DeBruijn et al. 2008)

2.1.2 Location

HPHT developments can be found in the North Sea, Haynesville play, US and also in the deepwater GOM both in the US and Mexico (Figure 5, Figure 6 and Figure 7).

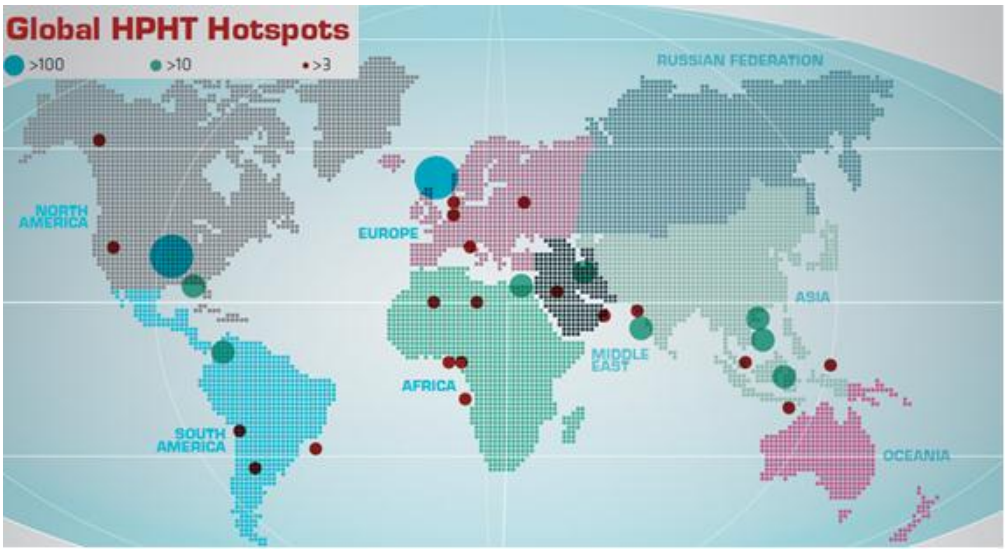

Figure 5 Global HPHT Hotspots (Oil_and_gas_iQ 2013)

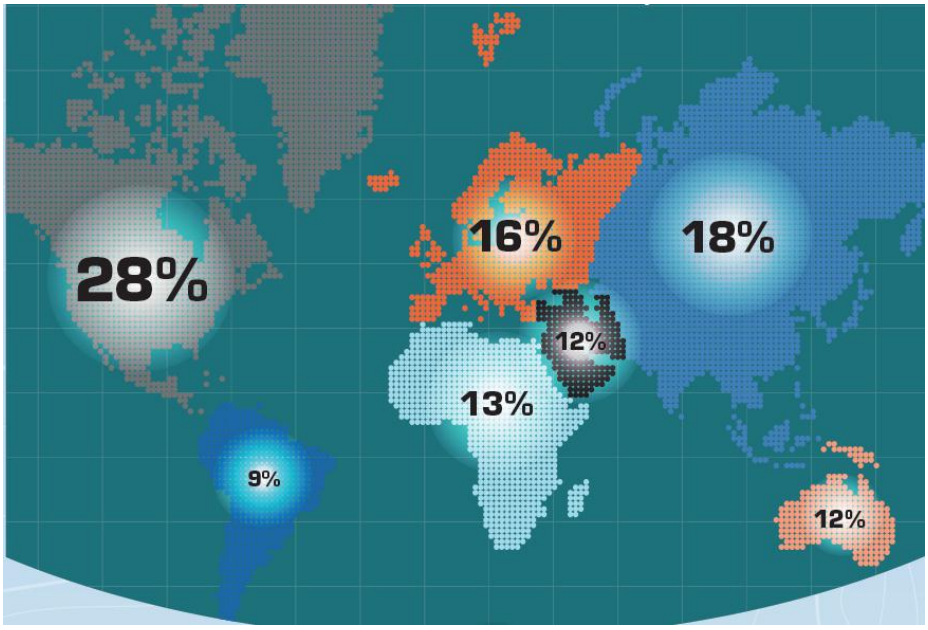

Figure 6 Regions Will See the Biggest Growth in HPHT Wells in the Next Two to Four Years (Oil_and_gas_iQ 2015)

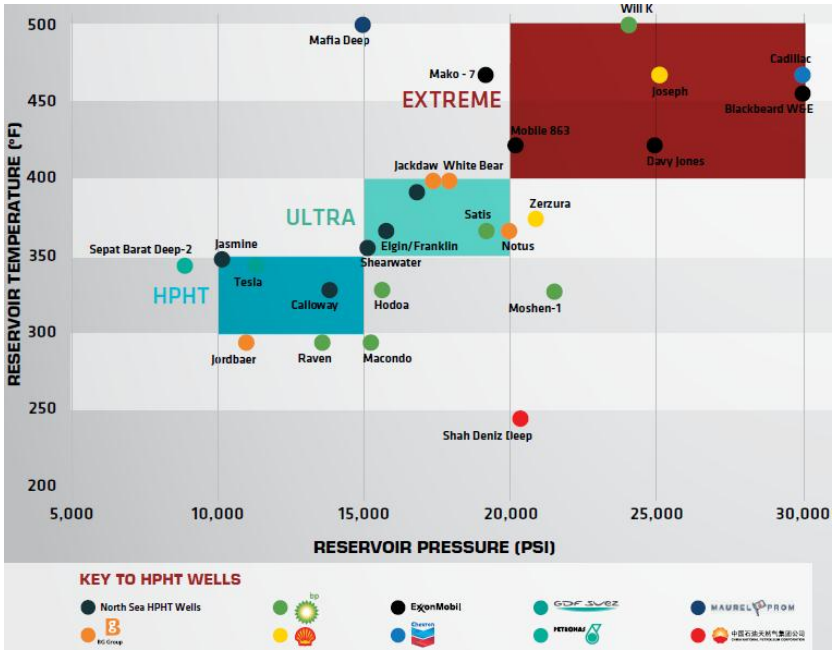

Figure 7 Notable HPHT Wells Drilled So Far (Oil_and_gas_iQ 2013)

2.1.3 Costs

The cost of HPHT wells situated in deepwater is high since the rig rental is about 70 % of total cost and trip times are long due to great depths.

The special well design expense for HPHT environments cannot be overlooked when estimating the cost and can add 20 % - 30 % to the total cost. About $240 MM per well, which is a typical cost for Lower Tertiary GOM HPHT wells. A HPHT resistant subsea pump costs around $300 MM. (Figure 8)

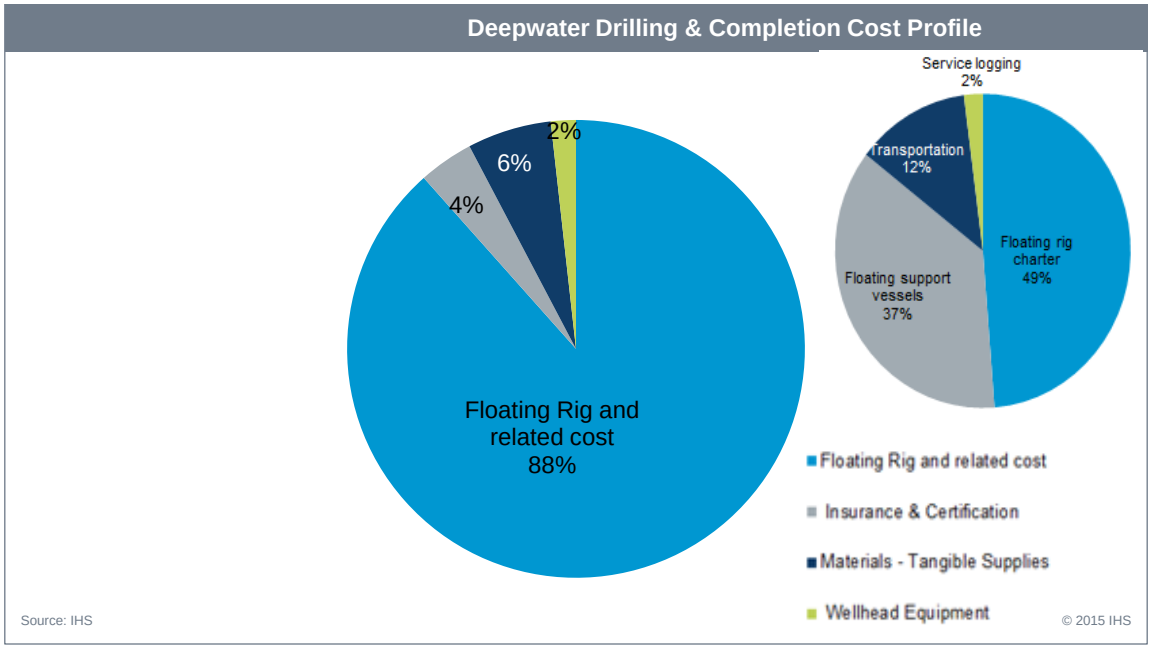

Figure 8 Drilling and Completion Cost Component (IHS_Global_Inc. 2016)

2.2 HPHT Challenges

2.2.1 Gaps

(Proehl and Sabins 2006) have identified three different gaps:

(1) **Physical**. It reffers to the possibility of conducting particular operations and employing methods to reach a geological goal to drill and complete a well.

(2) **Economic**. It reffers to the worthiness of a specific operation, due to operation or method cost.

(3) **Regulatory**. It concerns to the allowance of conducting operations and employing methods to drill and complete wells.

One of the most important failure factors in the recent blowouts and hence spills in the GOM, was a deficient cement job (Shadravan and Amani 2012). In 2013, well

control and intervention was choosen the most important challenge in London HPHT well summit, nevertheless in 2015, material issues were the top challenge (Figure 9).

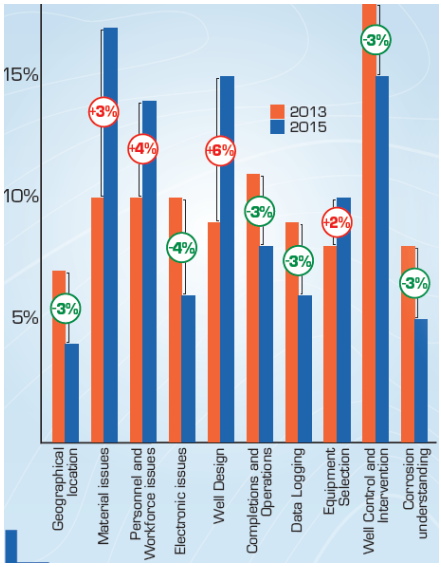

Figure 9 Biggest Challenges Faced by Operators (Oil_and_gas_iQ 2015)

In 2013 the main knowledge gaps lied in seals and in 2015 lied in cement design and formation, (Figure 10) highlighted some key facts about the wells that are pushing the boundaries of hydrocarbon technology to the limit.

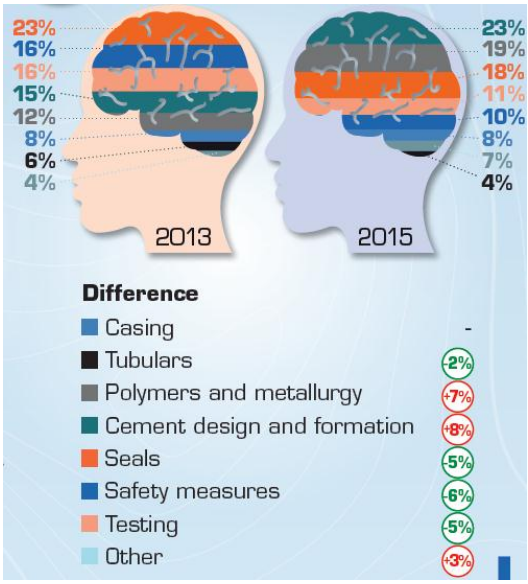

Figure 10 Knowledge Gaps (Oil_and_gas_iQ 2015)

For designing the tools, it is neccesary to take into account more carefully the technical concepts in HPHT drilling, such as formation and fracture pressure, rheological properties, casing setting depth, hydraulics, cementing and bit selection. Casing-while-drilling and managed pressure drilling (MPD) could make a safe drilling operation by decreasing the non-productive time (NPT). The primary concerns of planning HPHT wells are in the following list (Proehl and Sabins 2006).

1. Evaluation Capabilities Limitations
    - Most wireline tools are very limited to 500 °F, they just work to 425 °F.
    - For MWD batteries works to 400 °F.
    - By increasing temperature sensor accuracy decreases.
    - LWD/MWD tools are unfailing to 388 °F (WorldOil 2016).
2. Low ROP in Producing Zone

- Compared to normal drilling for GOM wells bits commonly remove 10 % of the rock (Radwan and Karimi 2011).
- In PDC bits crystalline structure breaks down.
- Impregnated cutter drilling is slow.
- Roller-cone bits are inappropiate.
- ROP has been improved by a better turbines and motor designs.
- To improve reliability and penetration rates; motor, bit, mud and drill string dynamics must be optimized as a whole.
- Eventhough high torque solutions are offered by pumps, torque is a issue.

3. Well Control

- Owing to lithology and geopressure, fluid loss is an issue.
- The drilling window is very narrow.
- Solubility of H_2S (hydrogen sulfide) and methane in OBM.
- Mud storage because of Hole Ballooning.
- It is needed a well head design for 25,000 psi and 450 °F, according to Pallanich 2015, current design is 20,000 psi and 350 °F.

4. Non-Productive Time

- Tool failure and bit trips.
- Stuck pipe and twisting off.
- Decision making due to lack of experience.

- More hydraulic stability in HPHT/MPD or underbalanced drilling (UBD) operations is provided by continuous circulation drilling. Conventional circulation damaging drilling components or causing well control.
- Safety issues due to handling HT materials.

5. Drilling Fluid

- Reduce friction pressure and improve ECD.
- Coolant for LWD/MWD tools.
- Barite Sag.
- Drilling Fluid Loss.

There is a heat exchange caused by circulating mud, its rate between mud, formation and casing at any depth depends on thermal conductivity, temperature, velocity of the mud and specific heat capacity of the materials. Temperature propagation is encouraged by vertical conduction of heat when there is casing (Figure 11).

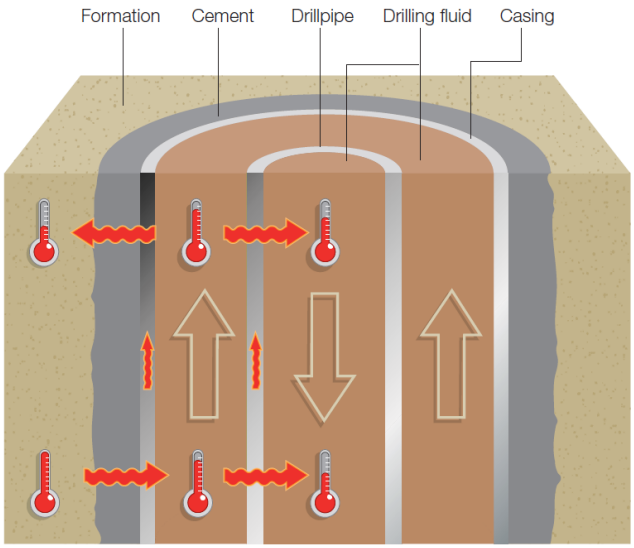

Figure 11 Heat Transfer in the Wellbore (Adamson et al. 1998)

Shadravan, Amani, Beck, Schubert, Zigmond and Ravi have done many HPHT tests on OBM and Water Based Muds (WBM) of US and Qatar fields using the Model 7600 HPHT Viscometer. Lee, Shadravan and Young analyzed the behavior of many HPHT Rheometers, by the study of rheological properties of a HPHT OBM they made suggestions to the American Petroleum Institute (API) committee (Amani 2012, Amani and Al-Jubouri 2012, Lee, Shadravan, and Young 2012). The recommended properties for HPHT drilling fluid are shown in Table 1.

Table 1 Properties of the HPHT Drilling Fluids (Shadravan and Amani 2012)

Drilling Fluid Properties	Required Performance in HPHT Wells
Plastic Viscosity	As low as reasonably possible to minimize ECD
Yield Stress and Gel	Sufficient to prevent sag, but so high as cause gelation, or high surge and swab pressures
HPHT Fluid Loss	As low as reasonably possible to prevent formation damage and risk of differential sticking
HPHT Rheology	Stable and predictable to control sag , gelation and ECD
Compressibility	Must be known to estimate downhole pressures and ECD
Stability to Contaminants	Stable in presence of gas, brine and cement
Gas Solubility	Needed for accurate kick detection and modeling
Stability to Aging	Properties do not change over time under either static and dynamic conditions but in reality properties slightly, drop after dynamic aging and increase after static aging.
Solid Tolerance	Properties insensitive to drilling solids
Weighting	Must be able to weighted up rapidly if a kick is taken

De Stefano, Stamatakis, and Young 2012, researched the challenges of HPHT drilling fluids and developed a fluid system. Xu et al. 2013, studied the high density WBM and also OBM for deep wells. An important point is the mixing of pressurizing fluid and test sample, in order to avoid the mingling of the two fluids, different cell designs have been used. Furthermore to guarantee enough thermal stability under xHPHT conditions good chemicals are neccesary for a good fluid composition, also

more research is needed to develop this products. Without a good thermal stability, simulation using data gotten at low pressure and temperature is unreliable, (Lee, Shadravan, and Young 2012).

The design of the hydraulics of the fluid depend on the affectance level of the fluid rheology by pressure and temperature in the wellbore. If these effects are ignored there are going to be errors with repair costs required during later stages of drilling. The main goal of the design of a drilling fluid is to mantain its properties in the wellbore. The rheological properties determine the capability of the fluid to carry cuttings and the amount of the drop of the friction pressure that happens during its circulation. This friction pressure drop, determine the pump pressure to keep circulation and the increment in pressure during circulation at the base of the wellbore (ECD).

It is neccesary to predict and control ECD for avoiding the fracture of the formation and lost circulation during drilling operations with narrow operating windows, it might generate well control and wellbore stability problems. The degree of the influence of temperature and pressure in fluid rheology is more difficult to predict than in density. The ECD and the hole cleaning capacity are affected by rheological properties changes. In deviated holes this problem is bigger, hole cleaning problems can cause a sidetrack that is time consuming and hence expensive, or in the worst scenario a well abandonment. The rheological changes in the wellbore have to be taken into account. Zamora studied the performance under xHPHT conditions of oils, synthetics and brines used to made OBM, Synthetic Based Muds (SBM), and WBM respectively (Zamora et al. 2012) Table 2.

Table 2 HPHT Drilling Challenges, Modified (Proehl and Sabins 2006)

HPHT Gaps	Pressure (psi)	Temperature (°F)	Issues	Opportunities
Drilling Fluids **OBM** **WBM** **SBM**	40,000 30,000 30,000	600 500 500	Gas/ H_2S solubility in OBM Friction pressure contributes to losses Mud cooling is beneficial	Reduce H_2S and methane sol. in OBM Reduce friction Improve cooling
Wellheads & Casing Hanger	15,000	350	20k psi, 350°F system will be developed. 25k psi system requires a totally new design.	Improve sealing technology. Amend API specs. Metal-to-metal sealing required for 25k psi.
Directional Drilling **Motors** **Control/Steering** **Long Sections**	25,000	425	Torque is the issue. Lack of torque causes motors to stall. Motor seals are an issue at high temps.	Improve turbines - Higher RPM and higher torque motors. Motor rated to higher operating temp
LWD / MWD **High Reliability** **Limit**	35,000* 20,000 30,000	390* 275 500	Developed by NETL* Exponential decrease in reliability from 275°F to 350°F. Calibration shifts at higher temperatures. Batteries have a 400°F limitation. Vibration reduces reliability. Telemetry is relatively slow.	Improve batteries (500°F). High temp electronics. Reduce work string vibration. Improve sealing. Real-time telemetry. H_2S and gas sensors.
Openhole Logging **All tools** **Limited Tools**	25,000 25,000	350 450	Limited tool availability at higher temps. Calibration shifts at higher temperatures.	Extend range to 500°F. Develop more tools for 500°F service. Consider fiber optics.
Bits **PDC & TSP** **Roller Cone Not Desirable**	30,000	500	Penetration rate is low. 10% of normal ROP.	Take a Systems Approach. Bits, Motors, Mud, Drill String. Continue work on cutters.
Rheometers	40,000 30,000 30,000 20,000 2,500	600 600 500 500 500	Lack of precision for low shear rates. Slightly different dial readings at same pressure and temperature (esp. at HPHT condition) as the result of different mechanical instruments designs.	Improve a compatible API procedure for the HPHT Rheology Testing.

As stated by Seddighin and Krishingee 2014, major challenges for drilling fluids in a HPHT environment are:

- Thermal degradation of the fluid.
- Changes in the weight and viscosity of the fluid.
- Changes in solubility of the water phase.

- Expansion and compression of the fluid, especially when using invert emulsions.

According to Marinescu, Young, and Iskander 2014, the list of challenges is still extended by operational issues:

- ECD – vital if the drilling mud weight (MW) window is narrow or the well construction dictate slim holes into the reservoir;
- High-Temperature Gelation – caused by the flocculation of clay or solids in mud. This requires a very tight control of the solids content and selecting thermal stable products for treatment;
- HPHT Fluid Loss – is affected by HT gelation and degradation and increases with temperature; for tight reservoirs it is very important to keep it very low, since mainly the filtrate invasion is the principal formation damage;
- Product Degradation – Can change all mud properties and system stability, it is time and temperature dependent;
- High solids content – elevates PV and compounds gelation related problems;
- Barite sag – a dynamic and static mechanism when high densities are necessary.

2.2.2 Sagging

It occurs when mud solids fall, caused by segregation. The principal problem generated is the difficulty of controlling BHPs. Heavy mud can produce induced fractures and lost circulation, in the other hand light mud allows formation fluid influx and wellbore instability. Both dynamic and static conditions sagging can be presented; the best condition is under low shear rate conditions prior to achieve static viscosity.

High-quality barite is vital for HPHT mud due to poor particle size distribution or impurities can generate big troubles intensified by HPHT conditions (Adamson et al. 1998).

Gravity may cause weighting material when there is not enough circulation (a). A barite accumulation at the bottom of the hole is caused by sagging (b). The barite accumulations can collapse the bottom of the wellbores (c). Finally, collapse can cause barite accumulation and thus the density can vary significantly (d) (Figure 12) According to Adamson et al. 1998, during sagging, the viscosity is lowered by shear thinning because of the motion of the solids.

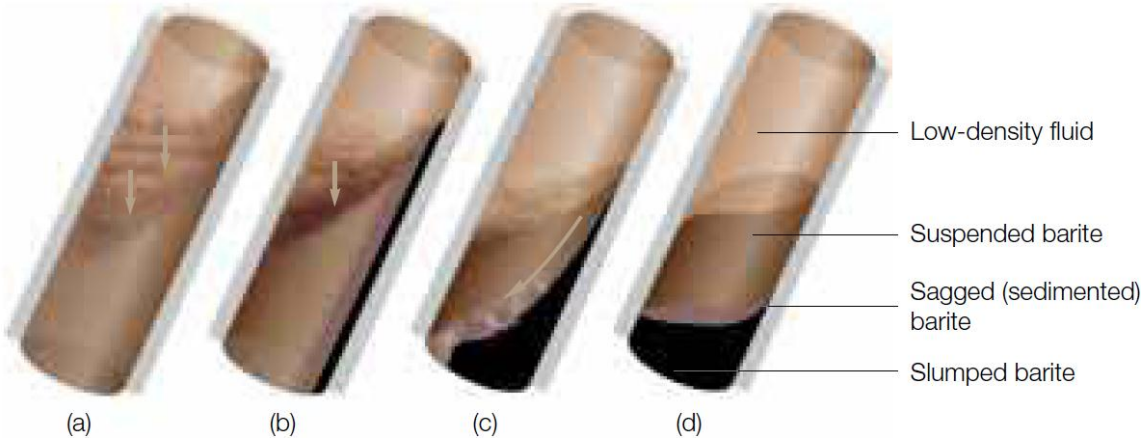

Figure 12 Sagging Process (Adamson et al. 1998)

De Stefano, Stamatakis, and Young 2013, studied how to help maintain suspension and minimize the settling and sag issues, by selecting a weighting material which was comprised of a high grade barite that was milled to an average particle size less than 2 microns. Typically the smaller the particulate size, the easier to suspend the particles in a fluid. In this particular case where micronized barite (D50<2 micron) is

much smaller than the API-grade barite (D50<45 micron), the measured static and dynamic sag of the weight material was very low.

The benefit of the micronized barite on drilling fluids and drilling operations can be listed as:

- For the same ECD, reduced pump pressure
- Improved ECD management in narrow hydraulic operating margins
- Reduced risk of ECD-related losses
- Reduced swab, surge and circulating pressure
- Improved Pressure While Drilling (PWD), MWD and LWD signal responses

The need of fluids for temperatures over 300 °F has grown more than the capacity of conventional bio-polymers to create rheological stable fluids. The HPHT drilling fluids, tend to sag; they also have syneresis where gel structure expels liquid; this calls for the need of a HPHT drilling fluid with anti-sagging abilities and high low shear rate viscosity (LSRV), to deal with this, Shah, Shanker, and Ogugbue 2010, formulated a specially organophilic clay with quaternary amines, it can withstand sagging of particles due to its reduced viscosity, it is incorporated at concentration of 0.5-5 lb/bbl to boost the ability of suspension, also using high-density thermally-stable polymeric solutions is accepted by the industry.

2.3 Rheological Models

The rheological models generally used by drilling engineers to study fluid behavior are Newtonian, Bingham Plastic, Power Law or Ostwald-de Waele, and Herschel-Bulkley.

2.3.1 Overview of Rheological Models

Consider a fluid contained between two large parallel plates of area A, which are separated by a small distance, L to understand the nature of viscosity (Figure 13).

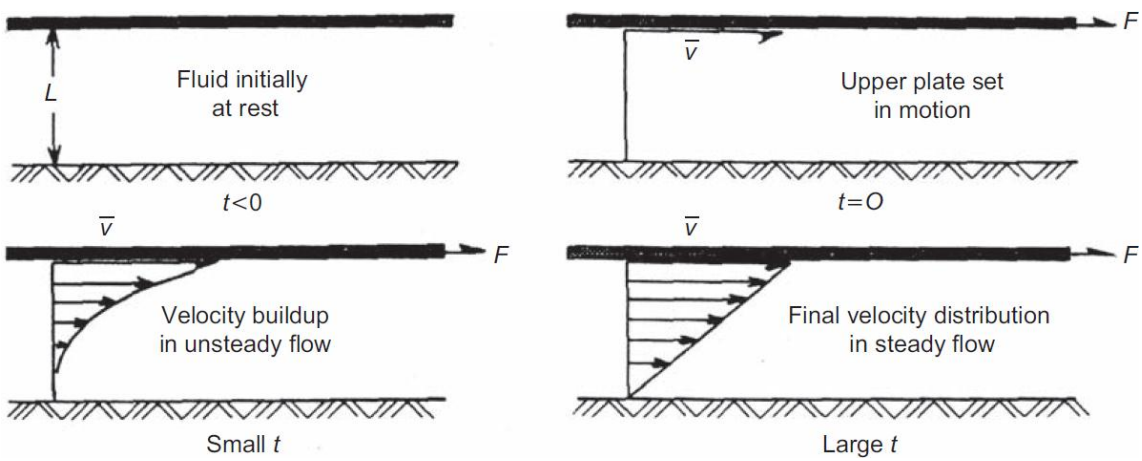

Figure 13 Laminar Flow of Newtonian Fluids (Bourgoyne et al. 1986)

For maintaining the upper plate moving at a constant velocity a constant force F is needed, by conducting experiments was found the magnitude of this force given by Equation 1.

$$\frac{F}{A} = \mu \frac{v}{L} \quad \textbf{(1)}$$

The shear stress is given by the term F/A. μ is the constant of proportionality called the apparent viscosity. Thus, shear stress is defined by Equation 2.

$$\tau = \frac{F}{A} \tag{2}$$

The area of the plate that the fluid is in contact with is represented by A. The velocity gradient v/L is an expression of the shear rate, Equation 3.

$$\gamma = \frac{dv}{dL} \approx \frac{v}{L} \tag{3}$$

The apparent viscosity is the ratio of the shear stress to the shear rate and relies on the shear rate at the moment of the measure and the previous shear rate history. Non-Newtonian Fluids are defined as the fluids that shear stress is not directly proportional to shear rate. Pseudoplastic fluids are non-Newtonian fluids that are shear-dependent and it apparent viscosity decreases by increasing shear rate and if the apparent viscosity increases are dilatant (Figure 14).

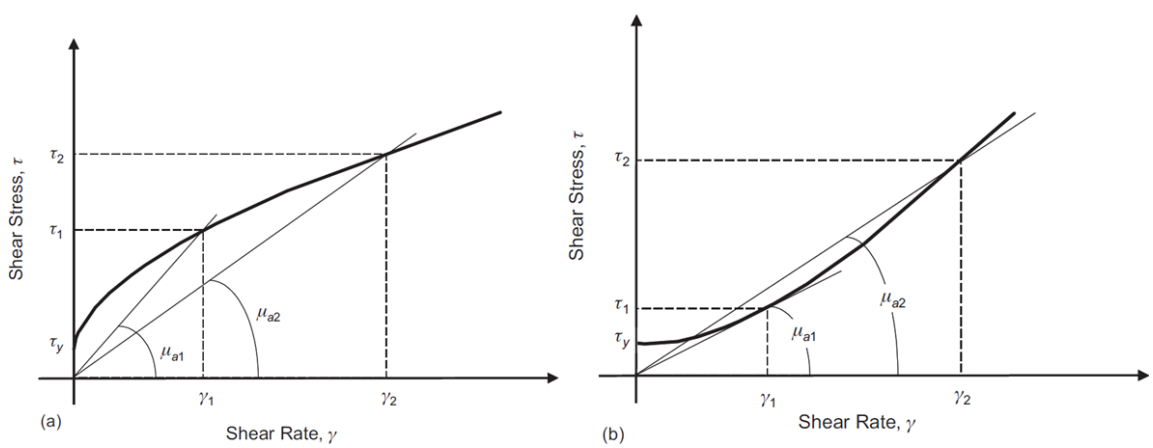

Figure 14 (a) Pseudoplastic and (b) Dilatant Behavior (Bourgoyne et al. 1986).

Many drilling fluids are generally pseudoplastic in nature. The Bingham Plastic model was fairly simple, but the Power Law model could handle the behavior of

pseudoplastic drilling fluids better than the Bingham Plastic model, particularly at low shear rates.

However, a typical behavior of the majority of the drilling fluids used includes a yield point (YP) (stress required to start fluid moving). The behavior of these fluids, called pseudoplastic, is characterized by a trend similar to that of pseudoplastic fluids and by the presence of a finite shear stress at zero shear rate, which is referred to as the YP. One of the rheological models that fit better this kind of behavior both at low and high shear rates is the Herschel-Bulkley model. Thixotropic fluids are Non-Newtonian fluids that are dependent on shear time and the apparent viscosity decreases with time after the shear rate is increased to a new constant value and if the apparent viscosity increases with time after the shear rate is increased to a new constant value are rheopectic (Figure 15). Drilling fluids are generally thixotropic.

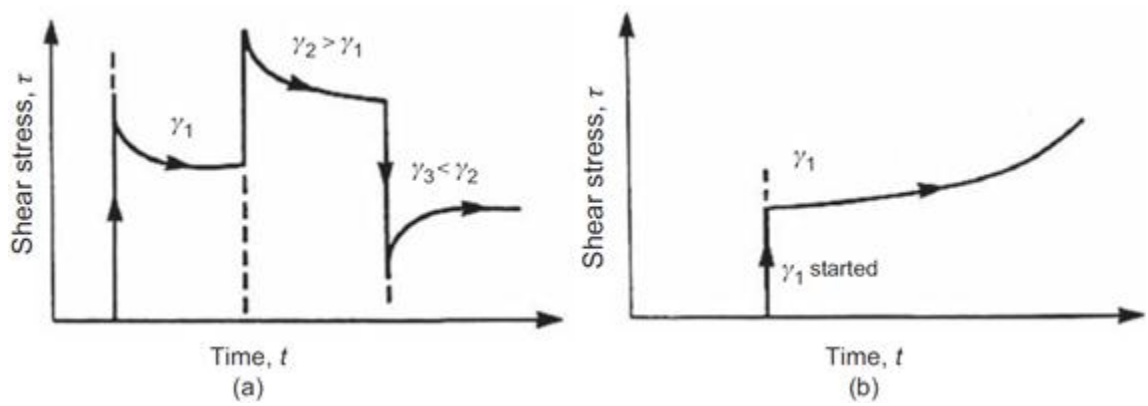

Figure 15 Shear Stress vs. Time for Thixotropic and Rheopectic Fluids: (a) Thixotropic and (b) Rheopectic Performance (Bourgoyne et al. 1986).

At present, the thixotropic performance of drilling fluids is not modeled mathematically. Nevertheless, drilling fluids are stirred normally prior to measure the apparent viscosities varying shear rates in order to get steady-state conditions. All the equations of the models presented are valid only for laminar flow.

2.3.2 Bingham Plastic

The Bingham Plastic model (Bingham 1922) is defined by (Figure 16).

$$\tau = \mu_p \gamma + \tau_y, where\ \tau > \tau_y \quad \textbf{(4)}$$

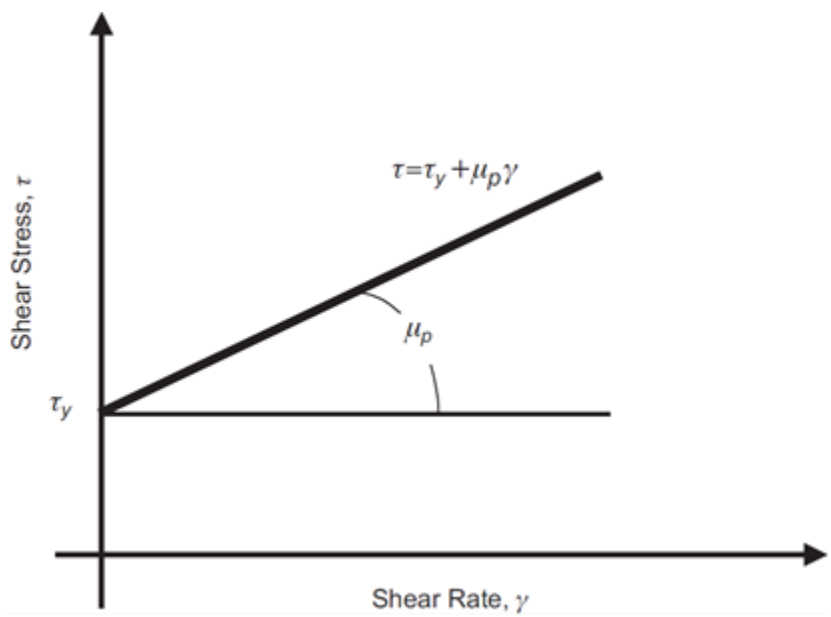

Figure 16 Bingham Plastic Rheogram.

In Bingham Plastic model a fluid will flow if the shear stress τ is greater than YP. Shear stress is proportional to shear rate, this ratio is called plastic viscosity (PV), μ_p. YP typically is showed in field units of lbf/100 ft^2. At high temperatures Bingham Plastic model diverge from the data tendency (Shah, Shanker, and Ogugbue 2010).

2.3.3 Power Law

The Power Law model (Ostwald 1925) is explained by (Figure 17).

$$\tau = K\gamma^n \tag{5}$$

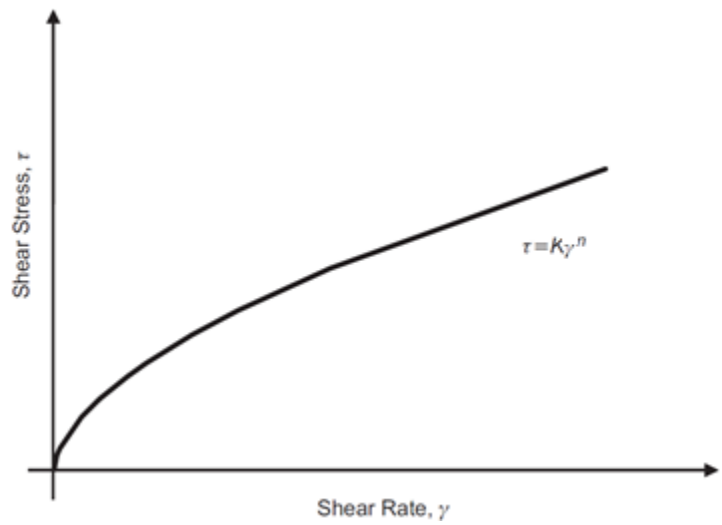

Figure 17 Shear Stress vs. Shear Rate for a Pseudoplastic Fluid in Power Law Model.

The Power Law model can be employed to depict a pseudoplastic fluid if *n* is less than 1, a Newtonian fluid if *n* is equal to 1, or a dilatant fluid if *n* is greater than 1.

The parameter *K* usually is called the *consistency index*, and the parameter *n* is called the Power Law exponent or *flow behavior index*. The variation of the dimensionless flow behavior index from 1 describes the degree to which the fluid behavior is non-Newtonian. The units of the *K* depend on the value of *n*. *K* has units of lbf-sec^n/ft^2.

2.3.4 Herschel-Bulkley

The Herschel-Bulkley model (Herschel and Bulkley 1926) is defined by (Figure 18)

$$\boldsymbol{\tau = K\gamma^n + \tau_y, where\ \tau > \tau_y} \quad \textbf{(6)}$$

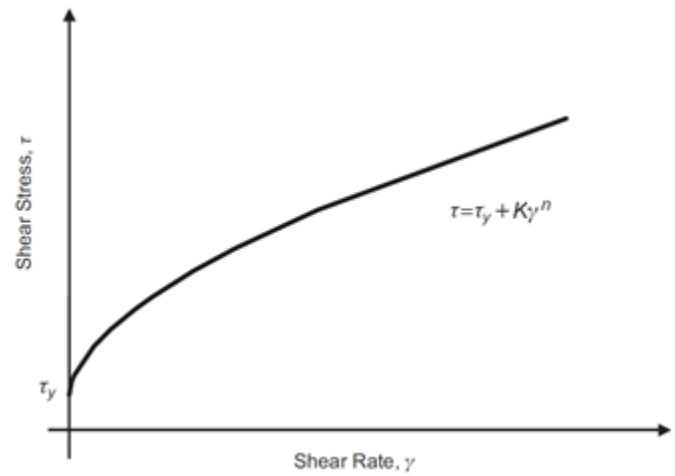

Figure 18 Shear Stress vs. Shear Rate for a Pseudoplastic Fluid in Herschel-Bulkley.

The model combines the Bingham Plastic and Power Law models and requires 3 parameters for fluid characterization. The model can be used to represent a pseudoplastic fluid if *n* is less than 1, a dilatant fluid if *n* is equal to 1, a pseudoplastic fluid if τ_y is equal to 0, and *n* is less than 1, a plastic fluid if *n* is equal to 1, or a Newtonian fluid if τ_y is equal to 0, and *n* is equal to 1. The model fits OBM and SBM across an extensive variety of pressures, temperatures and shear rates (Shah, Shanker, and Ogugbue 2010).

2.3.5 Rheometers and Viscometers

The difference between a viscometer and rheometer is essentially the quality of components and control capabilities. Basically, a rheometer is more versatile and has a wider range of applications than a viscometer does.

A rotational viscometer is simple device that rotates a spindle in a single direction. Most viscometers have mechanical bearings that limit the range of applications to more viscous materials. A viscometer is a low cost instrument that is suitable for simple material, process or production tests that require simple flow measurements. A viscometer is highly suitable for quality control testing and is often portable so offer the ability to do remote or field testing.

A rotational rheometer allows far significant description of flow and deformation performance. Rheometers can apply oscillatory motion to the spindles and big step changes in strain and stress to determine viscoelastic properties as well as flow properties. Rheometers usually use ultra-low friction air bearings which enable much greater sensitivity for low viscosity samples to be measured. Rheometers also tend to offer a wider range of sampling accessories such as temperature control units to study materials under a wider range of conditions (McDonagh 2010).

Rotational viscometers include Couette-type, parallel disk and cone and plate viscometers. In Couette-type, rheology can be measured by maintaining constant shear rate or shear stress (Shah, Shanker, and Ogugbue 2010).

Many of the HPHT Rheometers are design with an ideal pivot without friction and jewel to give the readings, this condition is not achieved if the test is influenced by

pressure, temperature, time of usage and type and content of solids; and hence affecting the nature of the information created under the most extreme limit of the instrument.

2.4 HPHT Drilling Fluids

In order to optimize drilling fluid properties, 3 variables can be manipulated: viscosity, pump rate and MW, the distinct optimizations of these factors can change the properties of the drilling system as shown in Figure 19.

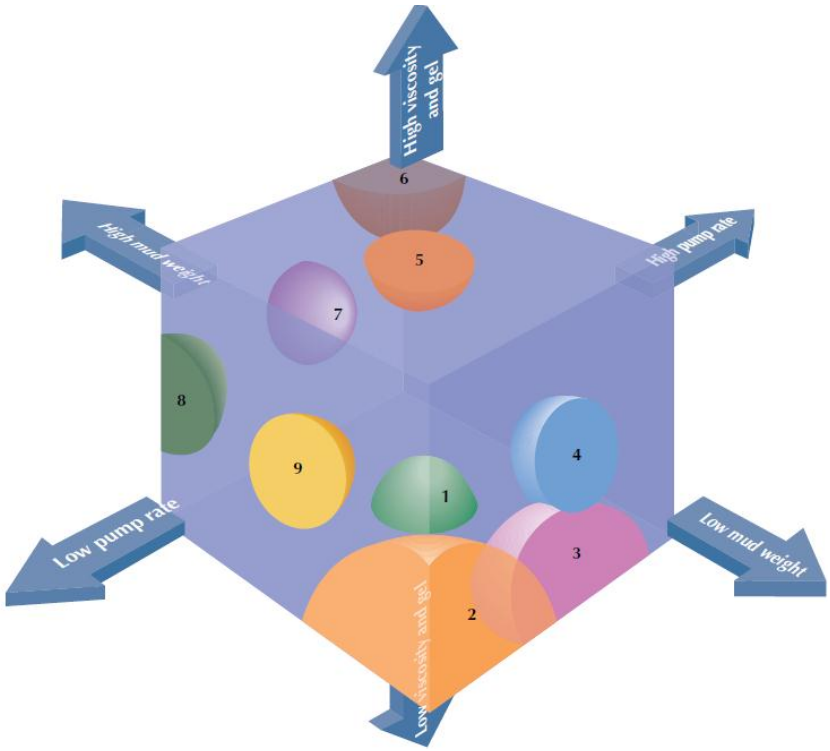

Figure 19 Optimizing Drilling Fluid Properties

1. Low conditioning requirements
2. Low risk of fracture and ECD
3. High rate of penetration

4. Minimized differential sticking
5. Minimized Sagging
6. Good hole cleaning
7. Maximum kick prevention
8. Washouts minimized by good hole stability
9. Hydraulic horsepower at bit increased (Adamson et al. 1998)

The success of drilling and its cost depends on 3 factors:

- The bit penetrating the rock
- The transport of the cuttings to surface and the cleaning of the bit face
- The support of the borehole

HPHT Drilling fluids require a good balance of mud properties to avoid oil and gas surge, kicks, formation damage and other risks. (Amani, Al-Jubouri, and Shadravan 2012)

2.4.1 Functions of Drilling Fluids

The main purposes of the drilling fluid are hole cleaning, formation pressure control, and carrying cuttings to the surface. According to Mitchell and Miska 2011 can be categorized as follows:

- Cuttings transport
    - Clean under the bit
    - Transport the cuttings up the borehole
    - Release the cuttings at the surface
    - Hold cuttings and weighting materials when circulation is interrupted

- Physicochemical functions
- Cooling and lubricating the rotating bit and drill string
- Fluid loss control
    - Wall the drilled wellbore with an impermeable cake for borehole support
    - Reduce adverse and damaging effects on the formation near the wellbore
- Subsurface pressure control
- Support drillstring and casing weight
- Ensure maximum logging information
- Transmit hydraulic horsepower to the rotating bit

2.4.2 Drilling-Fluid Categories and Classification

According to the *World Oil* annual fluid systems classification, there are 10 categories of drilling fluids in use (WorldOil 2015). Six categories include freshwater systems:

1. Non-dispersed.
2. Dispersed.
3. Calcium-treated.
4. High-performance water-based muds (HPWBM).
5. Low-solids.
6. Polymer/Polyamide (PA)/partially hydrolyzed polyacrylamide (PHPA).

One category covers saltwater systems, two categories include oil- or SBM, and the last category covers pneumatic (air, mist, foam, gas) “fluid” systems.

The principal factors to choose drilling fluids are:

- The formation characteristics and properties
- The water quality and source for the drilling fluid
- The ecological and environmental considerations

Drilling fluids can also be categorized by their *continuous* phase (Figure 20): WBM, OBM and pneumatic (gas) fluids.

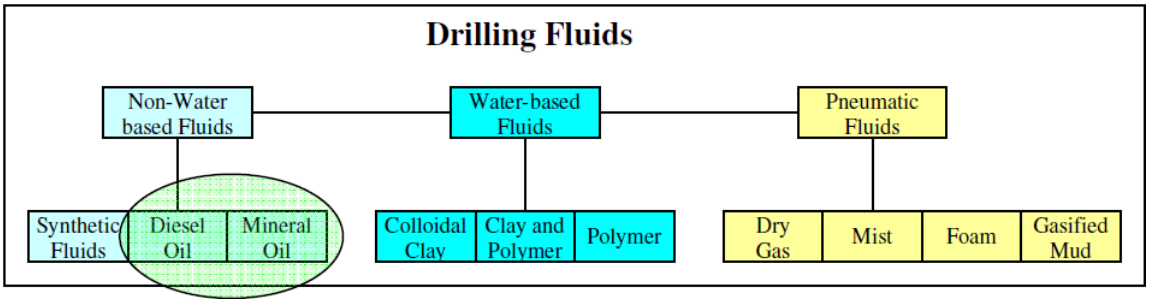

Figure 20 Drilling Fluids Classification by Composition. (Ibeh 2007)

2.4.2.1 WBMs

The majority of wells are drilled with WBMs. The base fluid may be fresh water, saltwater, brine, or saturated brine. Base fluids from OBMs are more compressible than WBMs, as they are environment friendly; drilling cuttings can be easy rid. WBMs range from native muds to lightly treated fluids to the more heavily treated, inhibitive fluids, they are classified in: inhibitive, non-inhibitive and polymer.

van Oort et al. 1997, discussed a method to improve the HPHT stability of conventional rheology modifiers and fluid loss polymers used in WBMs. The polymers are used as viscosifying agent, these can be linear polymers, cross-linked polymers, synthetic polymers, or bio-polymers, the method exploits the interactions of

polysaccharides (e.g. xanthan gum, scleroglucan), cellulosics (e.g. carboxymethyl cellulose (CMC), poly anionic cellulose (PAC)) and starches with polyglycols, he concluded that polyglycols delay the degradation of the fluid loss polymers at high temperatures.

Shah, Shanker, and Ogugbue 2010, studied a viscoelastic surfactant (VES) drilling mud which can re-heal it and reinstate the rheological properties, while VES based drilling mud is more expensive, it does not need frequent mud conditioning saving rig time. The cost could be less by blending VES with bio-polymers.

Amani and Al-Jubouri 2012, investigated the effect of HPHT on the rheological properties of WBM, they concluded:

(1) High YP is gotten by an increment in pressure until 15,000 psi later the YP falls. At low temperatures the pressure effect on YP is more noticeable.

(2) By increasing temperature PV decreases.

(3) The temperature changing effect is more noticeable than pressure. At temperatures below 250 °F the pressure effect on PV is more noticeable.

(4) At low temperatures (<250 °F) the increment in pressure results in higher viscosities. Viscosity decreases by increasing temperature until 350 °F then the viscosity values are small for all distinct rotor speeds. The effect of temperature on viscosity is more important than pressure.

(5) Gel strength (ability of a fluid to suspend solids) decreases with increasing temperature until 250 °F afterward generally it increases. The increment in pressure until

25,000 psi decrease gel strength then it grows. The pressure effect is more noticeable at low temperatures (<250 °F).

(6) For low density muds, YP is high until 300 °F. Viscosity is high for heavy mud samples until 400 °F, subsequently the variation between mud weights decrease. For low density mud, gel strength is normally high. The mud sample degrades at 250 °F.

(7) Rheology of the mud is affected in a complicated way by temperature and pressure.

(8) Mainly at temperatures lower than the degrade point, a suitable mathematical approach of the viscosity of WBMs is given by Herschel-Bulkley model.

In WBM systems for HPHT fluids, synthetic polymers are commonly used as primary viscosifiers and fluid loss agents, such as:

- sodium salt of sulfonated acrylamide and vinyl lactam
- sodium salt of sulfonated acrylamide, acrylic amide, sodium acrylate and vinyl lactam

As stated by Hassiba and Amani 2012, Sodium Chloride (NaCl) contaminated samples had higher shear stress-shear rate curves than WBM; whereas, Potassium Chloride (KCl) contaminated samples had lower shear stress-shear rate curves than WBM. These fluids can be polluted during drilling of salt and there is a lot of probability to find it in deep wells.

Calcium Chloride (CaCl) was found to have a more impact on rheology than NaCl. The incidence of salt additional lessens the hydration of active clays. Although the cost of CaCl is more than NaCl per unit (Amani et al. 2015)

HPWBM are usually reformulated polymer systems to bring clay and cuttings inhibition, lubricity and high ROP, shale stability, by the time that downhole torque and bit balling problems are minimized. In order to reduce pore pressure transmission HPWBM use products to stabilize the borehole similar to OBMs (WorldOil 2015).

According to Ofei and Al Bendary 2016, Potassium formate brine ($KCHO_2$) is usually used to stabilize the drilling fluid's performance under HPHT conditions as it helps in decreasing the flocculation of rheological properties of WBM under extreme temperature including the degradation of their rheological properties.

2.4.2.2 OBMs

The drilling efficiency of an OBM system can save time required to drill the well. These fluid systems are also subject to disposal regulations because of their toxicity. Mineral oil formulations are considered less toxic than diesel-based fluids, but not a suitable alternative where "greener" SBMs are available. The use of diesel or mineral OBMs is absolutely prohibited in some areas. The oil/water ratios typically range from 90:10 to 60:40. Generally, the higher the percentage of water, the thicker the drilling fluid is. High salinity levels in the water phase dehydrate and harden reactive shales by imposing osmotic pressures.

As stated by Ibeh 2007, many factors affect fluid rheology including pressure, temperature, shear history, arrangement and the electrochemical character of the segments and of the persistent liquid stage, and can be synthetized as follows:

- Physical. The pressure effect is predicted to be bigger with OBM due to the oil phase compressibility.

- Electrochemical. The ionic activity of any electrolyte and the solubility of any soluble salt present in the fluid increase while temperature increases.
- Chemical. Hydroxides react with clay minerals at temperatures above 200 °F, this produce a change of the structure and of the rheological properties.

According to Ibeh 2007, at constant temperature the YP values are less uniform, but they generally increase with increasing pressure or decreasing temperature. At constant pressure there was a steady decline in viscosity with increasing in temperature up to 450 °F, where there is an increment due to thermal degradation that produces a change in the composition of the fluid. The effect of pressure is strongest at low temperature. At constant shear rate it exists the term “two-way” heating and cooling down. Ibeh 2007, also concluded that there is a linear relation between pressure and viscosity whiles an exponential relation for temperature, as well that the temperature effects on viscosity of the OBMs are more noticeable at high pressures above 20,000 psi, while pressure effects overcome at low temperatures below 350 °F and the thermal degradation occurs quicker at lower pressures below 10,000 psi than at higher pressures if the shear history is the same.

OBM Advantages:

- Most of OBMs are stable until 450 °F as defined by rheology and fluid loss.
- High lubricity, used to drill through most troublesome shale formations due to the inhibition and temperature stability (Ibeh 2007).
- Provides better gauge hole and not to leach out salt by faster penetration rates.

- Control fluid loss excellent, no shale swelling, good cutting carrying ability and adequate lubrication to drill bits (Shah, Shanker, and Ogugbue 2010).
- By using palm oil as an alternative of diesel can be more environmentally friendly (Shah, Shanker, and Ogugbue 2010).
- Thin filter cake (De Stefano, Stamatakis, and Young 2012).
- Resistant to salt, anhydrite, H_2S and CO_2. (Amani, Al-Jubouri, and Shadravan 2012)
- Reduces differential sticking risk.
- Allow low pore pressure formations drilling.
- Exceptional corrosion protection.
- Last long time.

OBM Disadvantages:

- Makes more difficult the detection of a kick, because of solubility of gas in the base fluid (Adamson et al. 1998).
- The thermal expansion of OBM is bigger than WBM, generating pressure in the annulus (Bland et al. 2006).
- Reduced rheology and filtration control when exposed to temperatures higher than 300 °F for long periods of time (Ibeh 2007).
- Due to oil wet surfaces poor bonding between formation and cement.
- Deficient filter cake removal and possible environmental risks, like seepage into aquifers and causing contamination (Shah, Shanker, and Ogugbue 2010).
- High cost lost circulation problems.

- Emulsifiers used in OBMs can change the rock wettability to oil-wet (Amani, Al-Jubouri, and Shadravan 2012).
- The use of oil resistant rubber is needed; due to the circulating system rubber parts can be damaged.
- Fire risks due to low flash points of vapors.
- To diminish OBM loss supplementary rig equipment and modifications are needed (Abduo et al. 2015).

Amani 2012, drawn the subsequent observations based on rheology tests at HPHT conditions on two OBMs, one regular and the other HPHT resistant. By increasing temperature; viscosity, gel strength and YP decrease (before the sample degrades, for regular OBM). This performance was consequence of the thermal degradation of the polymers, solids, and other components of the sample and the development of the atomic separations that low its viscosity, gel strength and YP. Besides, it was inferred that YP and viscosity increase with pressure. At low temperatures (below degrade point, for regular OBM) pressure effect on these parameters, is more noticeable. The viscosity, YP, and gel strength was directly proportional to pressure and inversely proportional to temperature. The temperature and pressure dependence of viscosity was exponential. YP is used to analyze the capability of a mud to lift cuttings from the annulus. If the YP is high it means a non-Newtonian fluid, which carries cuttings better than a low YP fluid, a flocculant or a freshly dispersed clay, like lime increase YP and is decreased by the addition of deflocculant to

a clay-based mud. The OBM sample with regular formulation degraded at 400 °F and the HPHT sample resisted.

2.4.2.2.1 All-Oil Muds

Drilling fluids formulated with diesel- or synthetic-based oil and no water phase are used to drill highly variable salinity formation water intervals of long shale (Mitchell and Miska 2011).

In order to control viscosity and fluid loss asphaltic type materials are needed. An invert emulsion is required if the water turn into a polluting effect. Mud solids can become water wet and cause stability problems if water is not emulsified fast. Mud can be lost if the water wet solids blind the screens of the shakers (Amani, Al-Jubouri, and Shadravan 2012).

2.4.2.2.2 SBMs

The term “synthetic” is used for non-aqueous fluids formulated with the reaction of fundamental organic building blocks, such as methane or ethylene. Typically, the high salinity water phase of an invert emulsion or SBM aids to stabilize reactive shale and prevent swelling.

SBMs were developed to provide the highly regarded drilling-performance characteristics of conventional OBMs while significantly reducing the toxicity of the base fluid, due to the aromatic content is low. Consequently, SBMs are used almost universally offshore. The cost-per-barrel for an SBM is considerably higher than that of an equivalent-density WBM, but because synthetics facilitate high ROPs and minimize

wellbore instability problems, the overall well-construction costs are generally less, unless there is a catastrophic lost-circulation occurrence.

An example of synthetic fluid is an ester formulated with an alcohol and a natural fatty acid. Other synthetic fluids are alkylbenzenes, acetals and an assortment of aliphatic hydrocarbons derived from ethylene. The typical synthetic fluid is an internal olefin with a carbon chain length of C16-C18.

In 2002, an SBM formulated with an ester/IO blend became widely used, especially in deepwater operations where temperatures range from 40 to 350 °F on a given well, the fluid contained no commercial clays or treated lignites; rheological and fluid loss control properties were maintained with specially designed fatty acids and surfactants, the system provided stable viscosity and flat rheological properties over an extensive variety of temperatures.

2.4.2.2.3 Emulsion-Based Drilling Fluids (EBFs)

The external phase of an EBF is water or brine and the internal phase is oil, synthetic hydrocarbons replace oil as an internal phase, in order to make the two phases miscible a surfactant is used, this fluid is cheaper than OBM, however more expensive than WBM, furthermore can be safely disposed of and is environmental friendly (Shah, Shanker, and Ogugbue 2010).

In EBF gel strengths develop quickly, but are extremely shear-sensitive; as a result, pressures related to breaking circulation, tripping or running casing, cementing, and ECD are significantly lower than pressures that occur with conventional invert emulsion fluids. Lost circulation incidents appear to occur less frequently and with a

lesser degree of severity where EBFs are used. The EBF performs well from an environmental perspective and has met or surpassed stringent oil-retained-on cuttings regulations governing cuttings discharge in the GOM. The EBF is highly water and solids tolerant and responds rapidly to treatment.

2.4.2.2.4 Invert Emulsion Drilling Fluids

Invert emulsion fluids consist of an aqueous fluid emulsified into a non-aqueous phase. An emulsion is created between two incompatible liquids by reducing the interfacial surface tension of one liquid with an emulsifier, or surfactant, to allow that liquid to create a stable dispersion of fine droplets in the other liquid. The droplet size is small when interfacial tension is low; typically the more stable the emulsion will be (De Stefano, Stamatakis, and Young 2012). Invert emulsions are inhibitive, resistant to contaminants, stable at HPHT, lubricious, and noncorrosive**.** Onshore, they are the fluids of choice for drilling troublesome shale sections, extended-reach wells that would be otherwise prone to pipe-sticking problems, and dangerous HPHT H_2S wells. The basic components of an invert-emulsion fluid (Figure 21) include an oleaginous liquid (synthetic fluids, diesel or mineral oil, which serves as the continuous phase); brine (usually CaCl that serves as the discontinuous phase), emulsifiers, oil-wetting agents, organophilic clay, filtration-control additives, and slaked lime. The primary emulsifiers are calcium-based soaps. Secondary emulsifiers enhance temperature stability and are tall oils (Mitchell and Miska 2011).

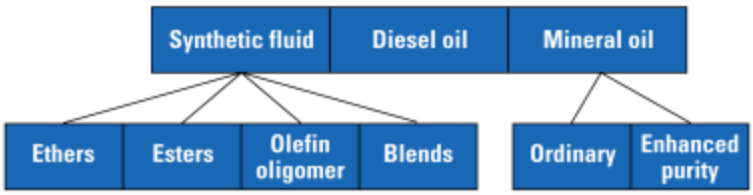

Figure 21 Invert-Emulsion Oil Muds (Schlumberger 2017).

These systems use synthetic, low aromatic/low toxicity base fluids or diesel oil. They can be weighted to densities above 19.5 ppg using barite or other weighted materials, for example ilmenite, hematite or Manganese tetroxide (Mn_3O_4). Typical oil water ratios (OWR) are in the 85/15-90/10 range (Bland et al. 2006).

Their advantages include creation of a lubricious thin filter cake, hole stability increment, greater ROP, does not react with shales, exhibit a low coefficient of friction, therefore is the right choice for extreme applications, where longer open hole sections and areas of pipe contact prevail.

Their disadvantages are: they are not biodegradable and unstable at HPHT, the thermal degradation of emulsifiers and fluid loss reducer can lead to gelation and syneresis, and as well loss of rheological properties can give rise to weight material sag, all potentially leading to associated well control problems (Shah, Shanker, and Ogugbue 2010).

Many invert drilling fluids can withstand 400 °F, but, at higher temperatures, the chemicals utilized are unstable and thermal degradation can happen in a brief time. (Lee, Shadravan, and Young 2012) studied the behavior of invert drilling fluid, when they reached 500 °F at 20,000 psi, the thermal degradation occurred, the fluid began to display inconsistent 100 RPM readings, then pressure was increased to 30,000 psi,

causing a considerable variation in the dial readings, since the fluid was so viscous. After the cell was disassembled, it was noticed that the fluid had separated into two phases with a clear oil phase on the top and a thick paste at the bottom of the cell. The xHPHT invert fluid holds products specially designed to withstand 600 °F, it had a good thermal stability as it exhibited very stable properties after heat aging. The most common emulsifiers for invert emulsion drilling fluids are surfactants distinguished to have functional groups that confer a polarity within the molecule, such as fatty acids, alcohols and amines (Young, De Stefano, and Lee 2012).

Almost all amido-amine emulsifiers are not capable to withstand temperatures above 450 °F, because they started to decompose, releasing ammonia and deteriorating fluid properties, for overcoming this challenge a emulsifier has been added to keep emulsion and fluid property stability, but this increment the cost.

The surfactant technologies provide a non-nitrogen based chemistry invert emulsifier that is capable to maintain stability of system properties and maintenance of oil wetting on prolonged exposure to temperatures in the 475-600 °F range (Young, De Stefano, and Lee 2012).

Invert emulsions are formulated to contain as much as 60 % of water; this is an integral part of the invert emulsion and can include a salt such as CaCl or NaCl. In order to tightly emulsify the water as the internal phase and prevent the water from breaking out and coalescing into larger water droplets, special emulsifiers are used.

Relaxed invert emulsion is when the fluid loss control of the system is relaxed with improvement in drilling rates; this uses more emulsifier than a regular invert

emulsion, (Amani, Al-Jubouri, and Shadravan 2012). Relaxed OBMs are formulated without filtration-control additives and have a loose emulsion.

2.4.2.3 Formate Brines

The birth of formate brines was in the early 1990's by Shell, the ideal solution was developing one fluid that:

- reduced hydraulic flow resistance
- eliminated solids sag
- did not solubilize hydrocarbon gases
- was not destabilized by the influx of reservoir gases
- reduced localized or pitting corrosion by acid gases
- eradicated stress corrosion cracking
- avoided corrosion inhibitors usage
- avoided causing formation damage

Formate salts derived from formic acid (HCOOH), and formulate by the incorporation of formate salts to fresh water, these format salts can be: sodium formate (HCOONa), potassium formate ($CHKO_2$) or anhydrous cesium formate (HCOOCs) (Howard 1995) (Figure 22).

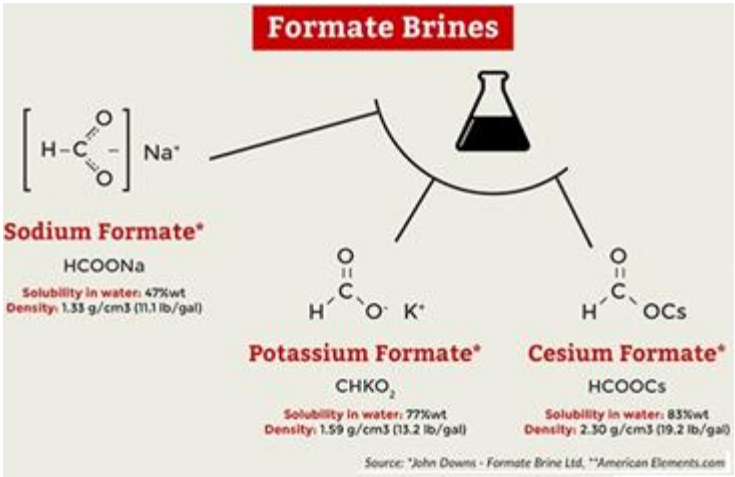

Figure 22 Formate Brines (DrillingPoint 2014)

Sodium formate brine, potassium formate brine, or both can be used to formulate low solids drilling fluids, from 8.33 to 13.35 ppg. as sodium formate is cheaper than potassium formate. Formates are very soluble in water and can be used to produce solids free brines or invert emulsions with densities as far as 19.7 ppg, it is needed a mixture of potassium and cesium formate with as much potassium formate as possible, reducing the need for weighting agents.

Xanthan gum is a viscosifier for formate brines, it creates the desired shear thinning rheology, is also stable to high temperatures. The concentration will vary from 0.5-0.75 ppb, depending on the required viscosity of the drilling fluid and the viscosity of the base brine.

Fluid loss polymers will be stable to higher temperatures in formate brines. Most formulations so far have been formulated with PAC, but starch has also been used. Three types of PAC have been used to formulate formate drilling fluids:

1. low molecular weight

2. extremely low molecular weight

3. ultra-low molecular weight

Although the formate drilling fluids are often referred to as "solids free", this is not entirely true, as a minimum amount of solids is required for the formation of a filter cake. The ideal filter cake material in a formate drilling fluid is calcium carbonate ($CaCO_3$) (chalk), which can easily be removed with acid. An amount of about 10 to 20 ppb is sufficient to create a thin and very efficient filter cake.

According to Howard 1995, 4 minerals can be used as weighting materials: Chalk ($CaCO_3$), Siderite ($FeCO_3$), Manganese tetroxide (Mn_3O_4) and Hematite (Fe_2O_3).

The advantages of formate brines are:

- Formation damage is minimal
- Better thermal stability
- Elimination of barite sag problems
- Minimize hydraulic flow resistance
    - Low ECDs
    - Low swab and surge pressures
    - Better power transmission to motors and bits
- Low gas solvency
    - Better kick detection and well control
    - Faster flow-checks
- Low probability of differential sticking
- Reduced torque and drag

- Naturally lubricating
- Hydrate formation inhibition
- Non-hazardous
- Low corrosion rates
- Compatibility with elastomers
- No stress corrosion cracking
- Environmentally friendly and biodegradable (Downs 2006)
- Due to high viscosity of filtrate and low water activity excellent shale stabilization.
- High formation strength and wellbore stability.

The disadvantages are: fluid loss in some cases is ten times more than a typical OBM, they are more expensive and made log analysis more complex (Ibeh 2007).

Formate muds are commonly protected with a carbonate salt, due to halides are very corrosive at high temperatures and constitute an environmental risk. In formate solutions corrosion rates are low, providing an alkaline pH. Formates are easily biodegradable and can be used without problems in environmentally sensitive areas. Low solids concentrations frequently enhance ROP and let good rheological properties control. Additionally formate brines have low water activity; hence, they decrease clay hydration and encourage borehole stability throughout osmosis (DeBruijn et al. 2008).

Recent research done by van Oort et al. 2015 in large scale drilling machines has shown that the ROP in formate brines can be up to 50 % higher than ROP in OBMs. To save cost a mixture should always be made with as much sodium formate as possible,

also can be formulated on pure potassium formate brine weighted to required density with solid weight material. When low rheology is desired is better to choose a slightly low brine concentration, and use some additional weight material. A cube of formate is 360 % more expensive compared to invert emulsion mud. By using formate, costs decreased by 27 % per lateral meter drilled for the entire well. The demand for formate brines has been growing 30 % per annum over the past decade.

2.4.3 Drilling Fluids of Ultra HPHT Well on the GOM Mexican Side

When higher temperatures to 204 °C (400 °F) are showed, the drilling mud, regardless of the base (oil or synthetic), does get a bit more than 40 % solids in its composition. To remain stable and functional, it requires constant dynamic conditions downhole, because the high temperature present in the drilled area affects and changes the rheological properties to a point of null effectiveness; leading to hole instability problems and influences of abnormal pressure zones, in this way organophilic clays and emulsifiers of latest generation are used, due to it increases thermal stability and reduces drilling mud filtrate (Figure 23).

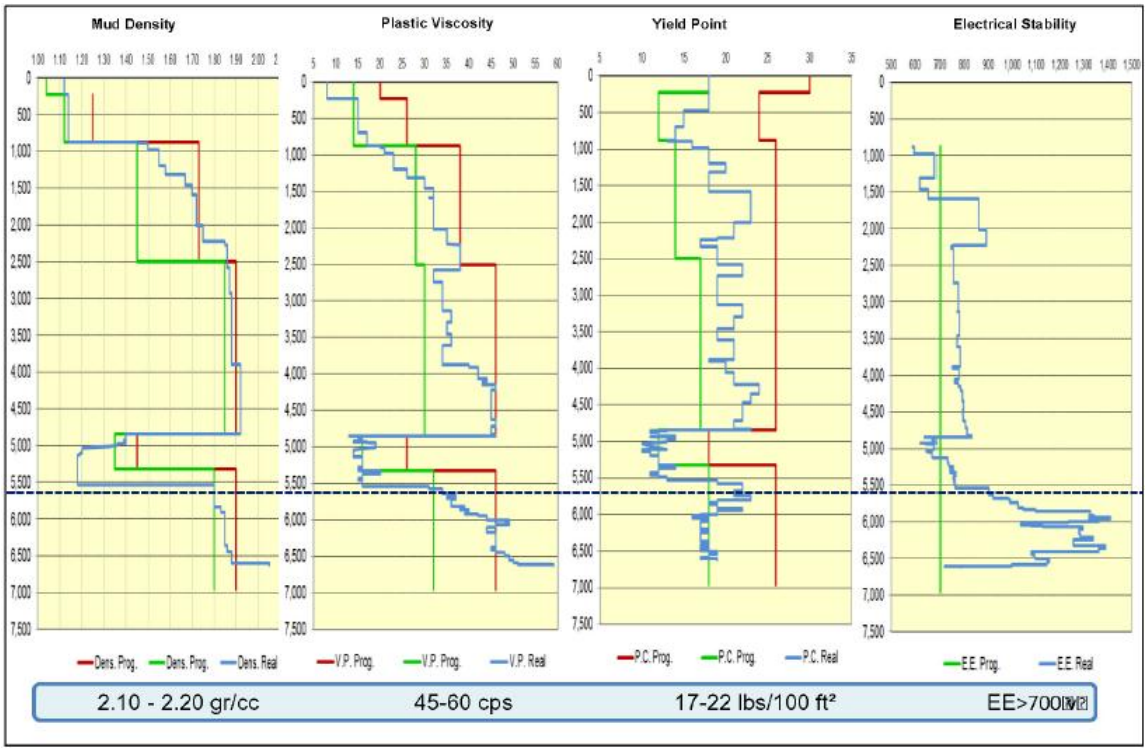

Figure 23 Real Behavior of the Rheological Properties During Drilling of Ultra HPHT Wells in the GOM (Ruiz 2016).

The simulation of mud in HPHT conditions provide determinant results where the minimum required rheological properties to maintain the drilling mud in static or dynamic conditions are established. Because drilling mud under static conditions presents settling heavy materials, particularly barite; plugging and weakening the drilled hole. When conditions are dynamic, the surface temperature of the sludge can reach a flash point that could endanger installations of the rig. According to Ruiz 2016, by increasing the temperature to 200 °C (392 °F), viscosity increases, which is due to activation of additives, but when temperature reaches 210 °C (410 °F) (with pressure ranging from 15,000 to 18,000 psi) the properties begin to decrease, indicating that is the

point where the additives lose performance and efficiency. Laboratory results not only determine the minimum required rheological properties, also provide valuable information to the design and optimization of hydraulic of the well with cost models, time traffic cycles and management of annular velocities, counteracting the effects by the high temperature in drilling mud as well as prolonged periods of preparation and conditioning. The design of the drilling mud to Ultra HPHT areas involves supplying of new materials in short periods through logistics and a large storage capacity, making sure it is in good condition. One of the best practices applied in the newly drilled wells that have substantial savings for Ultra HPHT wells is to include a support mud ship and a platform with plenty of dam capacity to pump new mud according to the time established by a risk analysis and laboratory simulations.

CHAPTER III

EQUIPMENT AND METHODOLOGY

3.1 Model 7600 HPHT Viscometer

Many of the HPHT wells have BHT greater than the MWD/LWD tools, which was one of the reasons for developing in 2005 the Model 7600 HPHT Viscometer to use temperature/hydraulic models as a source of downhole pressure data (Figure 24).

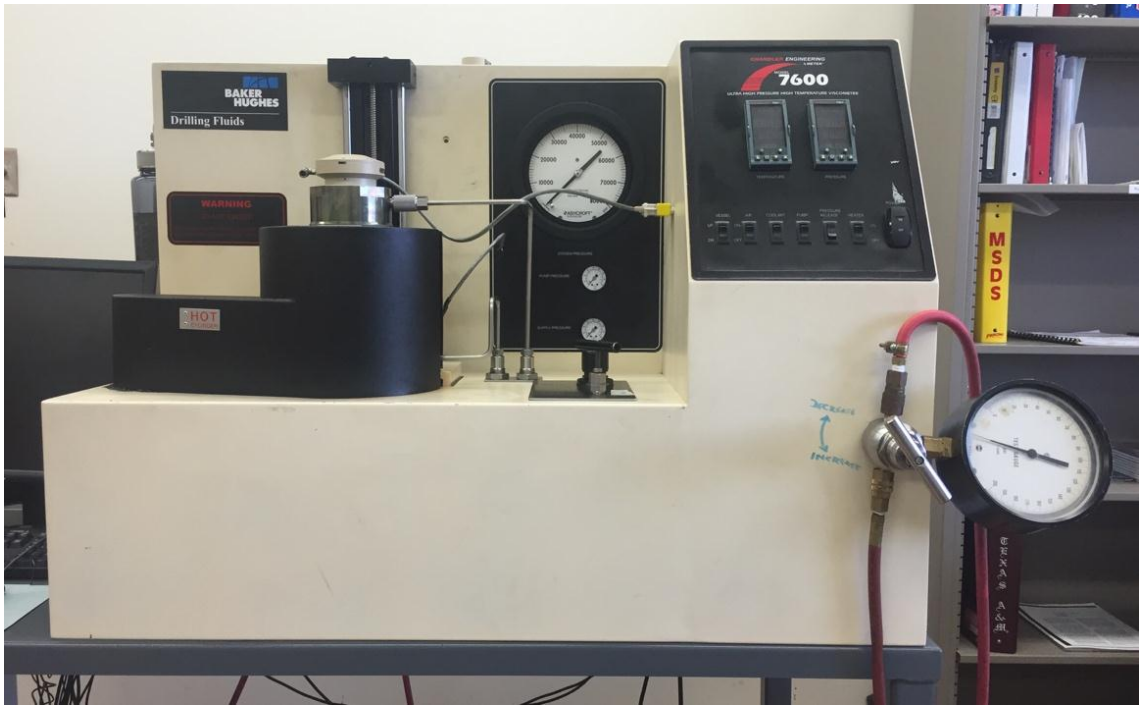

Figure 24 Model 7600 HPHT Viscometer.

Understanding the thermal and pressured behavior of HPHT emulsion systems is critical in understanding the effect on flow properties, ECD, equivalent static density

(ESD), and kick detection. As Baker Hughes Drilling Fluids (BHDF) developed HPHT fluid systems for more extreme environments, the need to test them posed the parallel challenge of designing a HPHT viscometer. The design criteria put forth by the technology team included a working temperature of 600 °F (316 °C), working pressure of 40,000 psi (276 MPa), the drive magnets are above the fluid sample to allow accurate viscosity measurements on fluids containing ferromagnetic materials and to reduce the chance of over-heating the magnets. The opportunity to achieve the criterion of perfectly steady, laminar flow is unlikely for high density, non-Newtonian high solids-content fluids used in HPHT viscometers (Gusler et al. 2006).

Reviewing the technology status of HPHT Viscometers, there are 3 designed according to API specifications with maximum temperature above 250 °F and maximum pressure above 200 MPa (Table 3), (Tianfu et al. 2014).

Table 3 HPHT Viscometers (Tianfu et al. 2014)

Company	Type	Maximum temperature	Maximum pressure
CHANDLER	7600	600°F(316℃)	40000 PSI (280MPa)
GRACE	M7500	600°F(316℃)	30000 PSI (207MPa)
FANN	IX77	600°F(316℃)	30000 PSI (207MPa)

BHDF and AMETEK Chandler Engineering built the first Model 7600 HPHT Viscometer, was put into service Q1 of 2005. In that year 2 additional units were built and reside in BHDF's Houston and Aberdeen laboratories. The original unit was donated to Texas A&M for further HPHT fluids research. Nowadays, there are 8 worldwide (Amani et al. 2015).

This is a Couette viscometer with a concentric cylinder that uses a rotor and bob geometry, also compliance with the necessities of ISO and API standards to measure the viscosity of HPHT fluids.

For this viscometer, the shear stress (torque) created between the bob and rotor is measured using a precision torsion spring and high resolution encoder. Known sample shear rates are created between the bob and the rotor using precision defined bob/rotor geometry and a stepper motor subsystem. Suspended solids in the sample are circulated during the test using a helical screw on the outside diameter of the rotor.

Features and Benefits:

- External digital torque measurement
- Separation zone between sample and oil
- Corrosion resistant steel super-alloys with high strength
- Programmable Pressure and Temperature Controllers
- Shear stress range: 5.1-1533 dyne/cm2
- Shear stress accuracy: ±0.50 %
- Shear rate range from 1.7 to 1533 sec^{-1} (1 to 900 RPM)
- Viscosity range: 2 cp at 600 RPM and 300 cp at 300 RPM.

3.2 Experimental Setup

The Model 7600 HPHT Viscometer consists of 3 main parts: top cap on the top part, top plug in the middle and vessel at the bottom. The bob and rotor cylinders are located inside the vessel where the fluid sample is, its capacity is 195 ml. The rotational

movement is transferred from an outer drive magnet, located around the top plug, to the rotor through the inner drive magnet, located inside the top plug. The bob shaft size is the length of the assembly and is attached on the top to a spring assembly that is located at the top part of the top plug inside the top cap. The rotational movement of the rotor, at specified shear rates, generates the movement of the fluid, and so the bob cylinder deflects, this angular deflection of the bob makes a metal piece inside the spring assembly to deflect; finally this deflection is detected and recorded by an encoder that is located above the top cap (Figure 25).

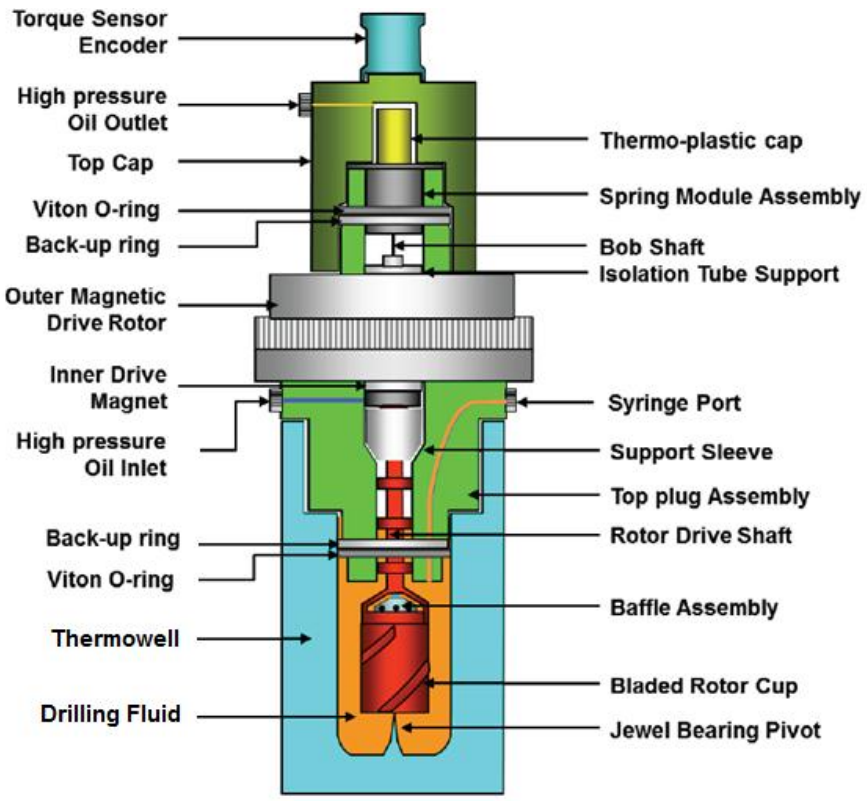

Figure 25 Chandler Model 7600 HPHT Viscometer Test Cell. Reproduced with Permission of (Ibeh, 2007), (Oliveira 2016).

The oil is circulated at low pressure in the system to push air outside of the pressure lines and the vessel, then the system operates in a closed mode at a set pressure and temperature, a pump that injects hydraulic oil into the vessel pressurizes the system. The hydraulic oil enters the vessel assembly through an inlet in the top plug and pressurizes the fluid sample in a separate conduit without getting mixed in with it in the bob-rotor section. Through the equipment's software program the user can adjust the oil pressure with a pump and a valve. The oil outlet of the assembly is located at the upper part of the top cap. When the valve is closed, there is no oil movement, so the pressure in the whole system would remain the same. An electrical heater transfer heat to the fluid sample through conduction when the pressure vessel is inserted in the heating jacket, a thermocouple detected this heat. It is important to say that unfortunately Texas A&M´s viscometer does not have a cooling system for letting to ramp down the temperature fast (Figure 26).

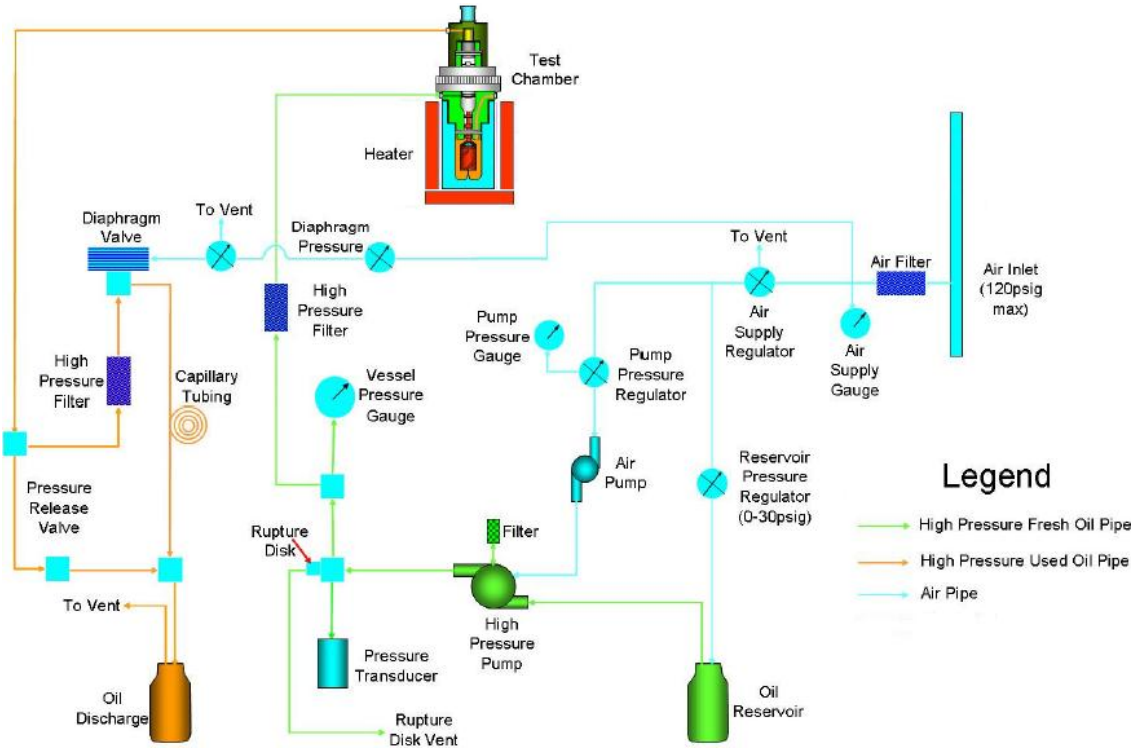

Figure 26 Fluid Flow Diagram (Ibeh 2007).

A Newtonian calibration fluid with a known viscosity value was used to calibrate the equipment before experimenting. The equipment automatically calculates the shear stress using the known viscosity values for a specific range of shear rate, and then the calculated shear stress is compared with the angular bob deflection recorded by the encoder.

3.3 Experimental Procedure

Important variations can occur during the course of this research because the OBM sample used is solids laden and therefore easily susceptible to sag.

3.3.1 Fluid Type

One OBM formulation was used during this research, it will be referred to as "Sample", below is a brief description of it.

3.3.2 Sample

It was brought from Ciudad del Carmen, Campeche, Mexico. This sample was prepared by M-I-SWACO to Pemex. It mud weight was measured using a mud balance getting the value of 13.5 ppg. The base oil was diesel and it was weighted with barite. The sample was obtained from the field in Offshore Mexico.

3.3.3 Fluid Preparation

The following actions were done prior to test the sample with the HPHT viscometer:

1. The fluid was blended with a pallet then with a mixer at 70 RPM for less than 5 min. to guarantee a homogeneous mixture.

2. Part of the sample was poured out to fill the 100 mL test tube and poured into the Erlenmeyer flask; the remaining 95 mL were measured and poured in the same way.

3. Using a hose from the adapter plug into an Erlenmeyer flask and pressurized the flask with a blue line of air connected to the flask adapter, the air supply was opened, also the valve that is in the front of the blue air line near to the manometer, next the sample was pumped into the cell, finally 195 mL of mud sample were injected.

3.4 Experimental Schedule

This viscometer as an automated unit needs initial programming of an operating schedule for the whole experimental cycle. The schedule contains magnitude and duration of each viscometer experimental condition in which viscosity is recorded in a special order automatically. Extensive initial tests were conducted to obtain a steady state operating schedule to obtain repeatable experiments (Anoop et al. 2014).

The test schedule used was test_pressures_Pedro_e_Rafael_9.sch, it is described by the succeeding steps: the pressure is raised to 10,000 psi later decreases to 5,000 psi and 1 hr. is waited, afterward 7 stages are run with temperature increments of 50 ºF from 100 to 400 °F (above this temperature smoke starts to appear), during every constant temperature stage the pressure is increased by 5,000 psi from 5,000 to 35,000 psi (38,000 psi is the highest pressure achieved), in each pressure step the shear rate first is raised to 100 RPM next to 600 RPM, subsequently decreases to 300, 200, 100, 60, 6, 3 RPM for taking dial reading, viscosity and shear stress values, after that, 10 sec and 10 min gel strengths are taken at 3 RPM.

The software this viscometer uses is Rheo 7000, with this all the orders are sent automatically to the HPHT Viscometer and the data is recorded. It uses the following equations to calculate shear stress, shear rate, and viscosity:

$$\boldsymbol{Shear\ Rate, \gamma = 2\omega \frac{R_o^2}{R_o^2 - R_i^2}, sec^{-1}} \quad \textbf{(7)}$$

$$\boldsymbol{Shear\ Stress, \tau = \frac{M}{2\pi R_i^2 L}, \frac{dyne}{cm^2}} \quad \textbf{(8)}$$

$$\boldsymbol{Viscosity, \mu = \frac{\tau}{\gamma}, \frac{dyne-sec}{cm^2}, Poise} \quad \textbf{(9)}$$

$$\boldsymbol{Angular\ Velocity, \omega = RPM \times \frac{2\pi}{60}, sec^{-1}} \quad \textbf{(10)}$$

$$\boldsymbol{PV = \theta_{600} - \theta_{300}, cP} \quad \textbf{(11)}$$

$$\boldsymbol{YP = \theta_{300} - PV, lbf/100ft^2} \quad \textbf{(12)}$$

$$\boldsymbol{Apparent\ Viscosity = \frac{\theta_{600}}{2}, cP} \quad \textbf{(13)}$$

where,

M = Torque on Bob shaft (dyne-cm)

L = Bob Height, cm

w = Angular Velocity, sec-1

Ri = Bob Radius, cm

Ro = Rotor Radius, cm

PV = Plastic Viscosity, cP

YP = Yield Point, lbf/100ft^2

Time = sec

Temperature = °F

Pressure = psi

Angle = degrees

Shear Stress = degrees (for a given spring constant) and dyne/cm2

Spring Constant = dyne-cm/degree

Viscosity = cP

Gel Strength = lbf/100ft^2

Shear Rate = sec^{-1}

Motor Speed = RPM

The shear rate at which gel strength is taken has to be adjusted in Preferences tab in Rheo 7000 software (Figure 27).

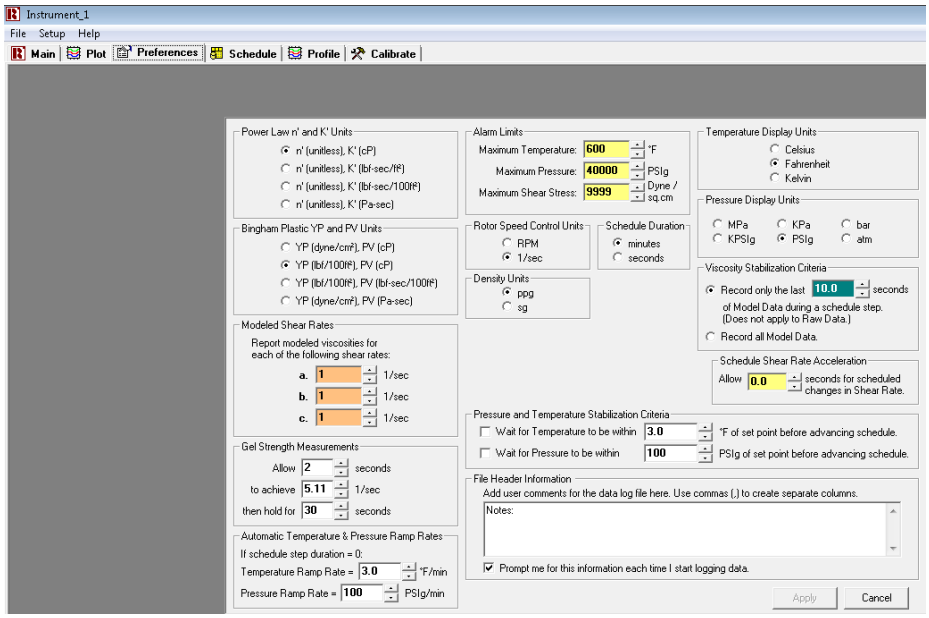

Figure 27 Gel Strength in Rheo 7000 Software

The rheology is resolved with the Bingham Plastic and Power Law models. For Bingham Plastic, the Rheo 7000 software automatically collects data at a rate of 1 reading per second for each desired schedule step. The average of this data is calculated for each schedule step and applied to the equations:

$$\mathbf{PV} = \frac{(\Sigma\gamma_{avg} \times \Sigma\tau_{avg}) - (N \times \Sigma\gamma_{avg}\tau_{avg})}{(\Sigma\gamma_{avg})^2 - (N \times \Sigma\gamma_{avg}{}^2)} \quad \textbf{(14)}$$

$$\mathbf{YP} = \frac{(\Sigma\gamma_{avg}\tau_{avg} \times \Sigma\gamma_{avg}) - (\Sigma\tau_{avg} \times \Sigma\gamma_{avg}{}^2)}{(\Sigma\gamma_{avg})^2 - (N \times \Sigma\gamma_{avg}{}^2)} \quad \textbf{(15)}$$

Where

τ_{avg} = Average Shear Stress for an individual schedule step during the data collection period.

γ_{avg}= Average Shear Rate for an individual schedule step

N= Number of schedule steps

The accuracy of the model is expressed as:

$$\mathbf{R}^2 = \mathbf{1} - \left(\frac{\sum \boldsymbol{\varepsilon}_\mathbf{i}^2}{\sum \boldsymbol{\gamma}_\mathbf{avg}{}^2 - \frac{\left(\sum \boldsymbol{\gamma}_\mathbf{avg}\right)^2}{\mathbf{N}}} \right) \quad \textbf{(16)}$$

Where ε_i represents the difference between the measured shear stress and the calculated shear stress using the Bingham Plastic equation for schedule step i.

In a similar way for Power Law model, the average of this data is calculated for each schedule step and applied to the equations:

$$\mathbf{n} = \frac{\left(\boldsymbol{\Sigma}\,\mathbf{log_{10}}(\boldsymbol{\gamma}_\mathbf{avg}) \times \mathbf{log_{10}}(\boldsymbol{\tau}_\mathbf{avg})\right) - \left(\mathbf{N} \times \boldsymbol{\Sigma}\,\mathbf{log_{10}}(\boldsymbol{\gamma}_\mathbf{avg})\,\mathbf{log_{10}}(\boldsymbol{\tau}_\mathbf{avg})\right)}{\left(\boldsymbol{\Sigma}\,\mathbf{log_{10}}(\boldsymbol{\gamma}_\mathbf{avg})\right)^2 - \left(\mathbf{N} \times \boldsymbol{\Sigma}\,\mathbf{log_{10}}(\boldsymbol{\gamma}_\mathbf{avg})^2\right)} \quad \textbf{(17)}$$

$$\mathbf{K} = \frac{\mathbf{10}^{\left(\left(\boldsymbol{\Sigma}\,\mathbf{log_{10}}\,\boldsymbol{\gamma}_\mathbf{avg}\,\mathbf{log_{10}}\,\boldsymbol{\tau}_\mathbf{avg} \times \boldsymbol{\Sigma}\,\mathbf{log_{10}}\,\boldsymbol{\gamma}_\mathbf{avg}\right) - \left(\boldsymbol{\Sigma}\,\mathbf{log_{10}}\,\boldsymbol{\tau}_\mathbf{avg} \times \boldsymbol{\Sigma}\,\mathbf{log_{10}}\,\boldsymbol{\gamma}_\mathbf{avg}{}^2\right)\right)}}{\left(\boldsymbol{\Sigma}\,\mathbf{log_{10}}\,\boldsymbol{\gamma}_\mathbf{avg}\right)^2 - \left(\mathbf{N} \times \boldsymbol{\Sigma}\,\mathbf{log_{10}}\,\boldsymbol{\gamma}_\mathbf{avg}{}^2\right)} \quad \textbf{(18)}$$

The accuracy of the model is expressed as:

$$\mathbf{R}^2 = \mathbf{1} - \left(\frac{\boldsymbol{\Sigma}\boldsymbol{\varepsilon}_\mathbf{i}{}^2}{\boldsymbol{\Sigma}\,\mathbf{log_{10}}(\boldsymbol{\gamma}_\mathbf{avg})^2 - \frac{\left(\boldsymbol{\Sigma}\,\mathbf{log_{10}}(\boldsymbol{\gamma}_\mathbf{avg})\right)^2}{\mathbf{N}}} \right) \quad \textbf{19}$$

Finally the test results are analyzed by doing conclusions and recommendations, if something is wrong, it is necessary to identify the causes and where is the problem located to recalibrate the damaged viscometer´s parts. (Ibeh 2007) did a workflow process for a typical viscometer test (Figure 28).

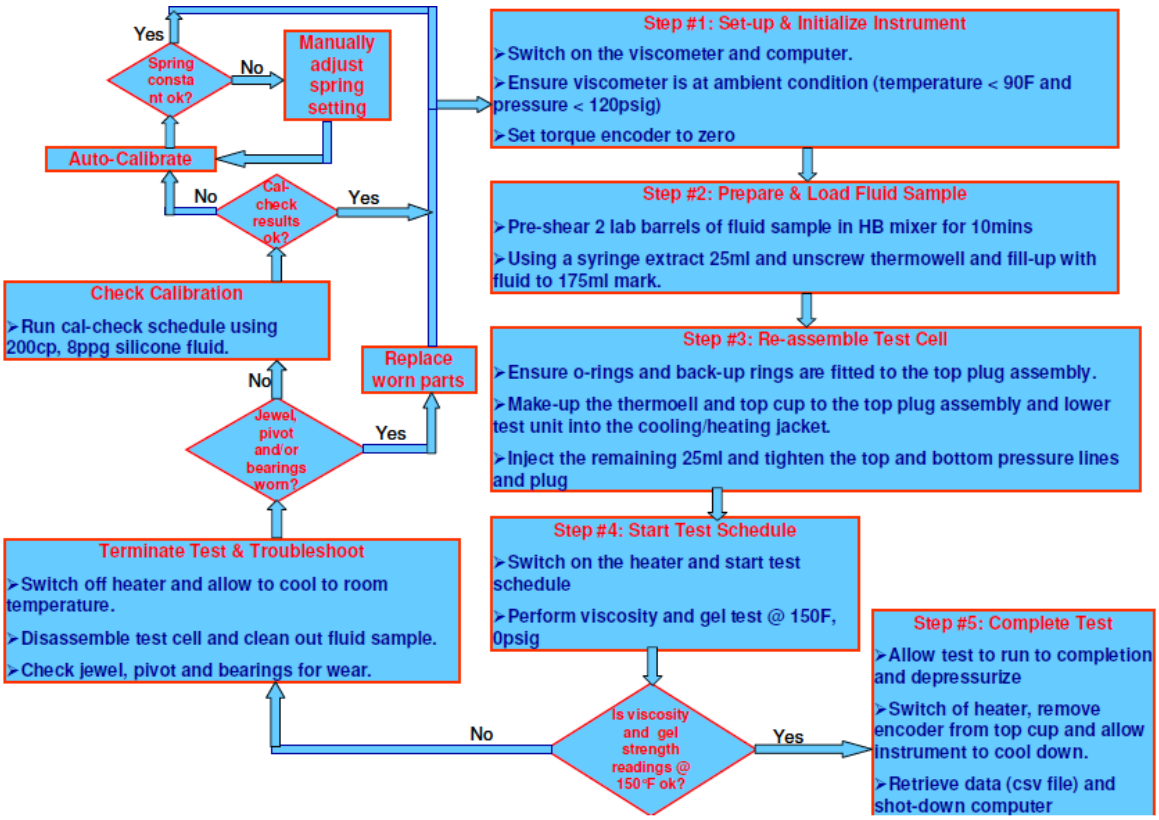

Figure 28 Work Flow Process (Ibeh 2007).

3.5 Equipment Problems

The first test was run on 11/3/2016 at 18:13:17 using water of 8.33 ppg., the schedule used was test_pressures_Pedro_e_Rafael_9.sch, the file to record it was named PemexWater2_2016-11-03.csv. As shown in Figure 29, the test failed 10:30 hrs. after it started the third stage, at 35,000 psi; since the first stage the pressure behavior was erratic, due to it didn't follow the pressure set in the schedule, also it can be observed that the pressure just dropped to 28,000 psi, not to 5,000 psi as was desired.

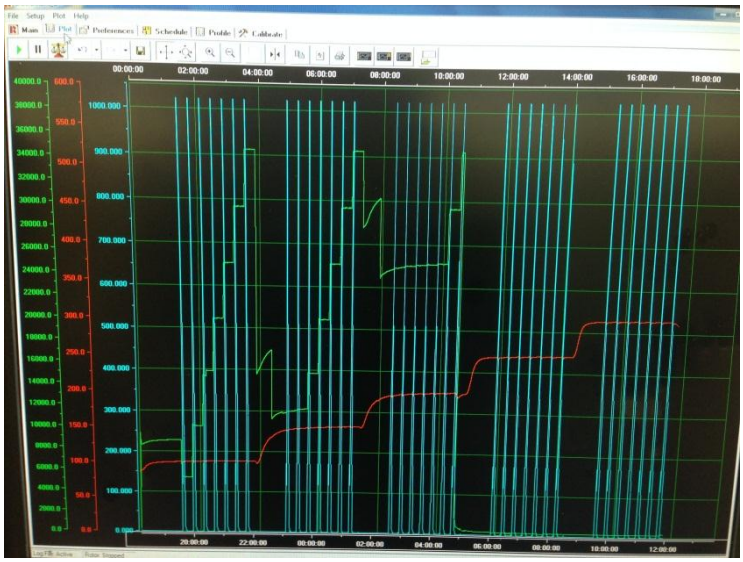

Figure 29 First Test Failure.

It is assumed that this failure was due to the Viton elastomer O-ring used as seal has been deformed (Figure 30) so it compromises the seal's integrity. It is suggested to make a re-inspection and recalibration of heating jacket and pressure transducer in line, within the 6 month maintenance schedule.

Figure 30 Viton Ring Failure.

In order to avoid this failure, it has to be ensured to place the Viton O-rings in the right way as shown in Figure 31.

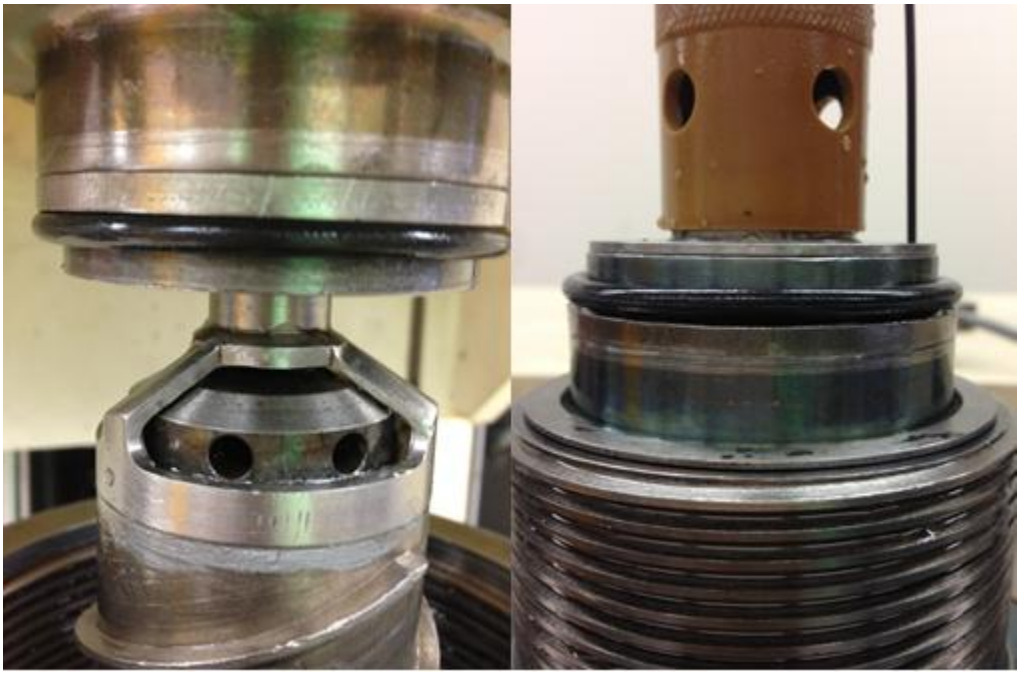

Figure 31 Correct Placement of Viton Rings.

The metallic back-up O-ring is found to be stuck at the top of the vessel frequently, due to the difference in diameters the bottom ring is 2.25 in, rather more than the top metallic ring 2.245 in.

Another test was attempted to run, but the message below appears (Figure 32). The solution was to restart the PC.

Figure 32 Rheo 7000 Software Error.

The second test was run on 11/8/2016 at 11:21:30, using the 13.5 OBM sample, the schedule used was test_pressures_Pedro_e_Rafael_9.sch, the file was named Pemex2_2016-11-08.csv, during the development of the test it failed owing to the fact that the pressure didn't increase Figure 33.

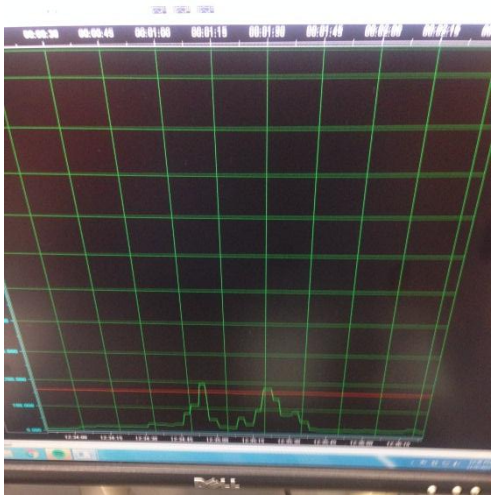

Figure 33 Pressure Increment Failure.

The connections of the back side of the viscometer were verified Figure 34, but just a non-representative little drop of oil was found.

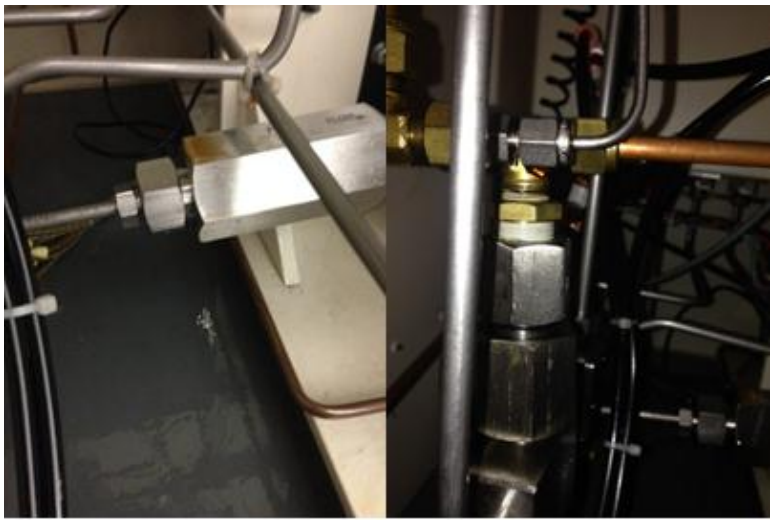

Figure 34 Connections of the Backside of the Viscometer.

The real problem was the black T-valve was worn out, so another one had to be bought (60-12HF4), in view on the fact that in the lab there were only 40,000 psi valves. Owing to the problem of the pressure was not raising continues, hence it was noticed that the capillary tube was clogged (Figure 35), therefore it was replaced with another thinner that was in storage.

Figure 35 Capillary Tube.

On 11/29/2016 at 16:27:44 another test was attempted with the schedule test_pressures_Pedro_e_Rafael_9.sch, the file was named Pemex2.1_2016-11-29.csv. Figure 36, but did not yield the expected results. After repeated testing there have been deviations in dial readings from the initial calibration, this occur due to the strong magnetic field of the magnetic drive excites the spring, the transmissibility curve characteristics also affects, there is a speed at which the spring oscillation increases a lot for a given spring constant and system mass, to remedy this the spring setting has to recalibrate and manually readjust.

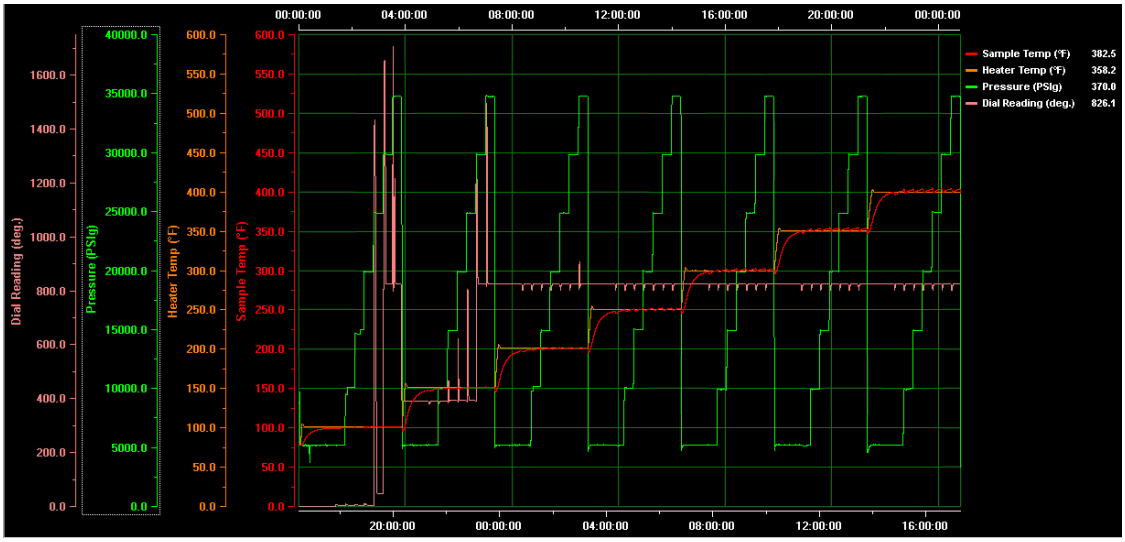

Figure 36 Dial Reading 11/29/2016 Test.

Figure 37 displays how the rotor, the vessel and the Viton O-ring looked after the test.

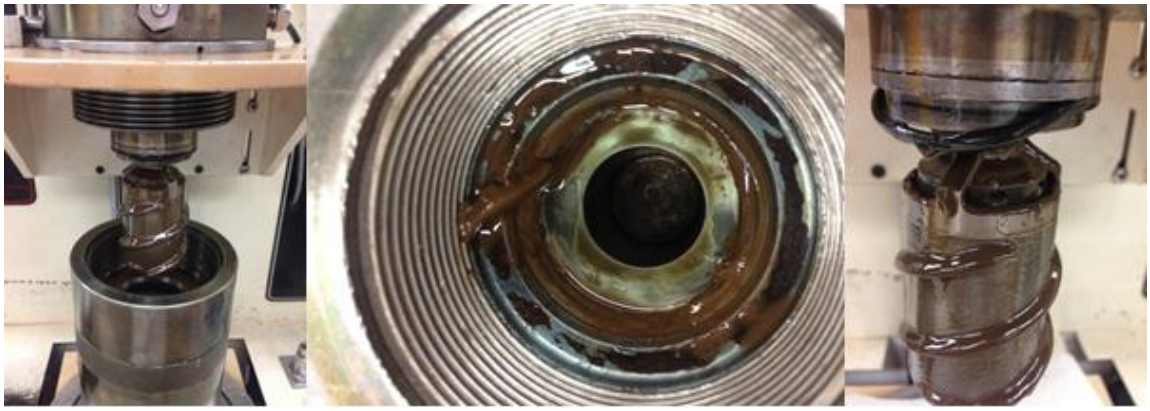

Figure 37 Rotor Assembly, Inside of the Vessel Assembly and Viton O-ring After Mud Test.

During the disassemble process of this test, 7600-1234 shaft assembly, adjustable baffle was broken, since it was too tight (Figure 38), thus a new one had to be purchased.

Figure 38 Broken 7600-1234 Shaft Assembly, Adjustable Baffle.

3.6 Future Improvements

Better Temperature Control: It is necessary to install a cooling system to control better the temperature. Currently, the cell cools naturally if readings are taken while cooling down. An ice bucket and a motor can be used as cooling system, because the original one replacement is so expensive

Rheo 7000 Software: It is needed to solve the skips a step ahead of the desired step when jumping steps on a pre-designed test schedule in further versions. Besides a pop-up decision box is needed to save the test data when accidentally the program shuts down. It must have at least a third rheological model to calculate the properties: the Herschel-Buckley, as it fits better the performance of drilling fluids, since it has YP and Power Law does not.

Oil Leakage: There is usually hydraulic oil leaking below the viscometer, after tests. It is necessary to improve equipment design to contain the oils from the pump muffler and hoses.

Top plug: It needs another 7600-1181 PIN, VESSEL ALIGNMENT (grip point), because when the top cap is too tight, it results very difficult to remove it, even with the strap wrench.

Spring module assembly: The pivot has to be immovable in order to avoid mistaken dial readings. There must be a spring that allows for higher shear stress readings.

Timing Belt: It has a lifetime; during the running of one test it was broken, because it was worn out. It cannot be used any timing belt like one used for cars, due to

it can melt at HT, as well as it has 163 teeth, the measurement between teeth is 0.2 in. and the circumference measures 32 in.

Baffle, Shaft, and Isolation tube support: One test has been run without these devices and the results look very similar.

3.7 Safety

Any instrument that is capable of HPHT should always be operated with caution and safety. Texas A&M HPHT team has not have any incident or injury for over 11 years, this has been possible by following the safety standards.

The required safety training taken to access the 509 lab was:

- 11020: Hazard Communication
- 811010: TEES Laboratory Safety Course
- 811006: TEES Hazard Waste Disposal

To guarantee safety, these actions were taken:

- Caution signs were posted near the instrument to warn non-operating personnel
- Before operating an instrument all instructions in the manual must be read.
- All caution notes and warning labels on the instrument must be observed.
- The instrument maximum temperature and pressure ratings should never be exceeded.
- Before attempting any repair, the main power of the instrument must be disconnected.

- The heater, power switch, air compressor at the end of each test must be turned OFF.
- Fire extinguishers within close proximity to the instrument are necessary to be located.
- The oil on the heated surfaces that may pose a hazard to starting a test must be removed.
- Open the pressure vessel until temperature is below 100 ºF.
- It is necessary to inspect the cell prior to any test.

When working with drilling fluids and heavy lifting equipment the following personal protective equipment (PPE) is needed:

- Organic vapor respirator
- Chemical resistant clothing with a protective apron
- Nitrile hand gloves
- Splash goggles
- Rubber-soled safety boots.

All waste fluids and materials are safely contained and appropriately disposed The Material Safety Data Sheet (MSDS) of every material was obtained and read prior to storage or use.

In 81010 are contained all emergency exit and first aid procedures. If a spill happens, these are the steps to follow:

- While wearing PPE locate the source of spill and stop.
- Absorb the spilled hydraulic oil and dispose in according to 811006.

- Clean the floor with a scrub and allow drying to avoid slipping.

CHAPTER IV

RESULTS OF EXPERIMENTS AND DISCUSSION

Finally two similar test results have been gotten, but in one of them the dial reading didn't come back to zero Figure 39, so the one that goes to zero after each stage was chosen Figure 40.

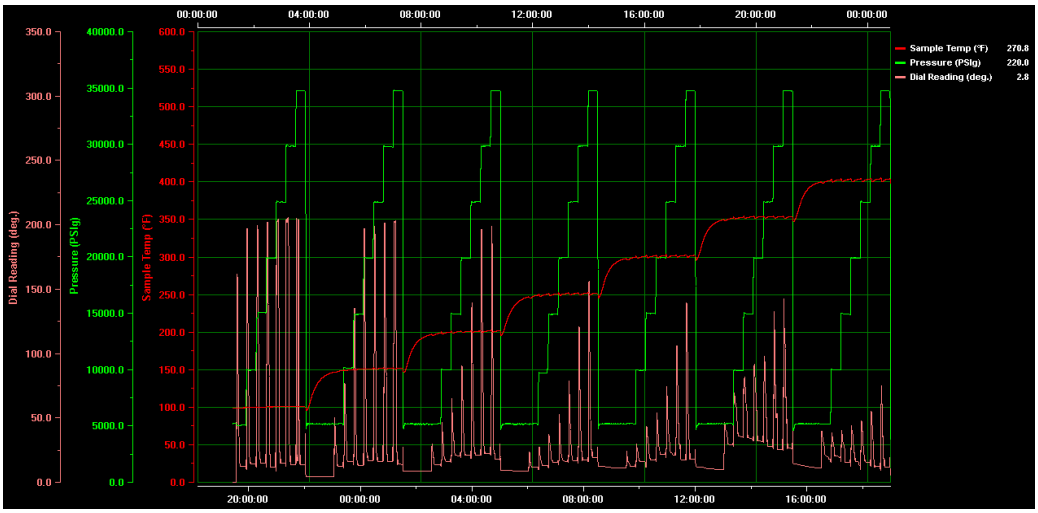

Figure 39 Dial Reading did not Come Back to Zero After Each Stage.

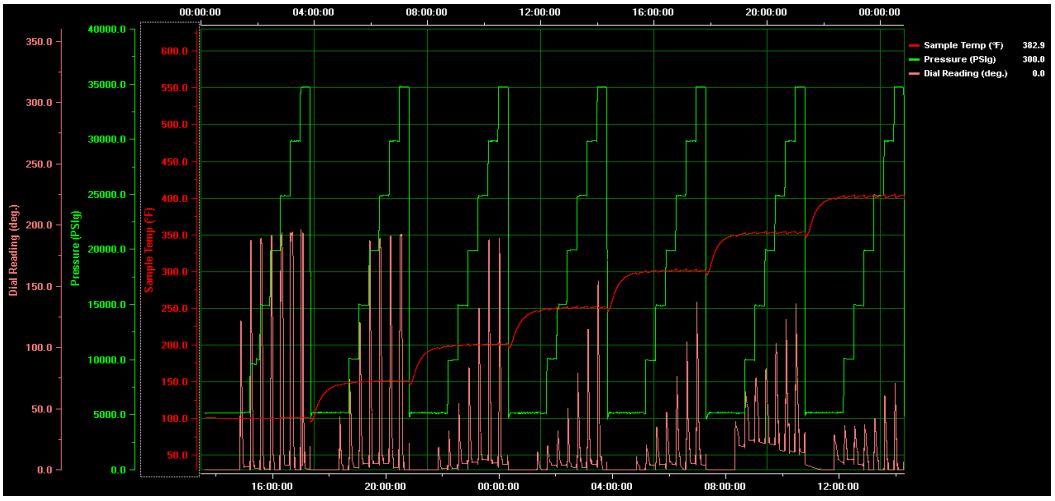

Figure 40 Dial Reading Comes Back to Zero After Each Stage.

In the meantime another test was performed, but it didn't perform the desired behavior, because the dial reading values in the first, second and third stages went so high up to 1,400 deg., above 360 deg., it seems out of range, as can be seen in the picture below Figure 41, then was concluded were incorrect readings, even the encoder was tested and it seemed to work well, however it fails.

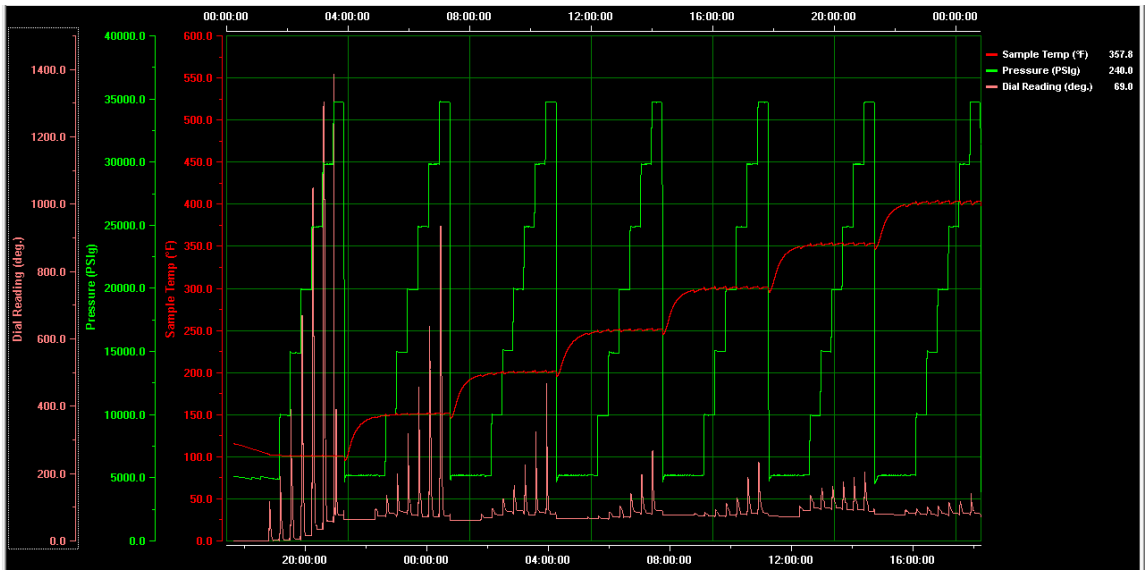

Figure 41 Failed Test.

The main point to take into account for running tests in this viscometer is the 7600-1029 SPRING MODULE ASSEMBLY, if the spring set screw is not placed in the correct way in the bob shaft, gently lift the magnet and tighten the set screw (1/16) (Figure 42). The set screw must tighten on the flat spot on the bob shaft.

Figure 42 Tighten Set Screw.

Verify free rotation of the magnet and bob shaft. If binding is detected, find and correct the interference, in order to not have incorrect readings, also if the pivot of the 7600-1021 SHAFT ASSEMBLY, INNER ENCODER is not fully out, the dial readings are going to be above 360 deg. Figure 43.

Figure 43 Pivot out.

At 13:28:11 on 2/13/2017 the best results were gotten with the same schedule test_pressures_Pedro_e_Rafael_9.sch, in the file PemexOBMsch9_2017-02-09.csv, with the same MW=13.5 ppg.

Figure 44 exhibits the final schedule run in the viscometer; the behavior of the parameters (shear rate, temperature and pressure) was the desired.

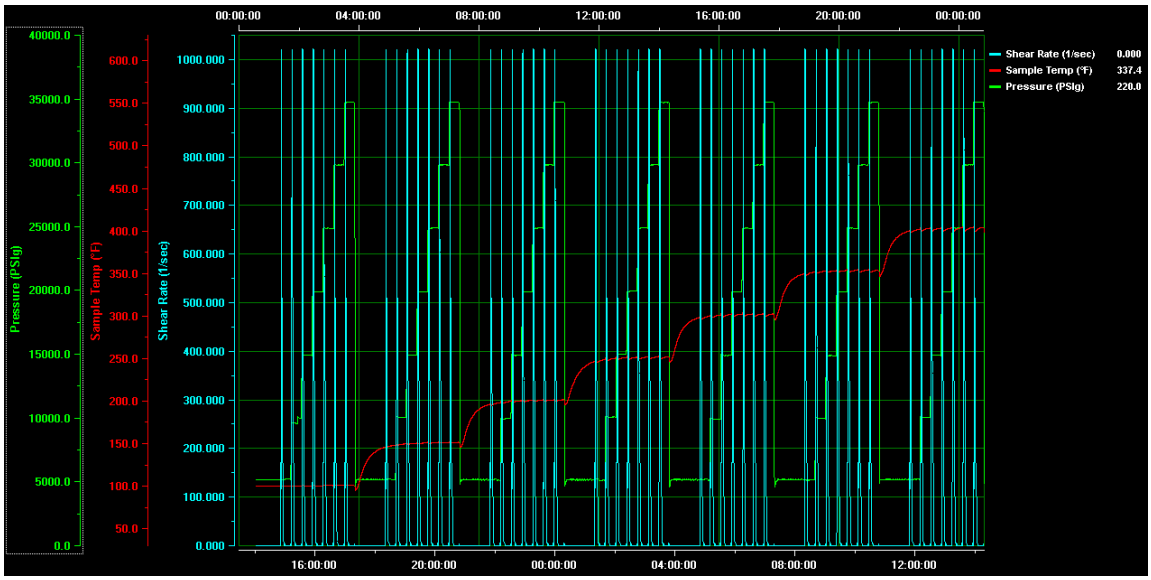

Figure 44 Final Schedule.

Figure 45 shows the shear stress reading values corresponding with shear rate, the behavior cannot see very well, but in the graphs that are shown after it can be seen.

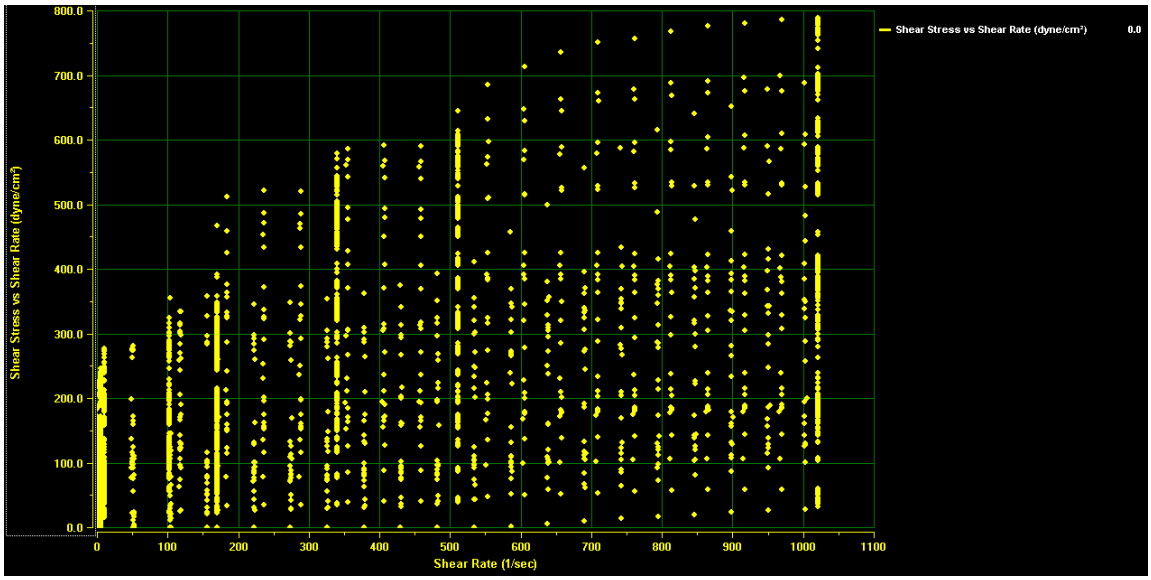

Figure 45 Shear Stress vs. Shear Rate.

Figure 46 shows the shear stress decreasing behavior until 300 °F, after that at 350 °F it increases.

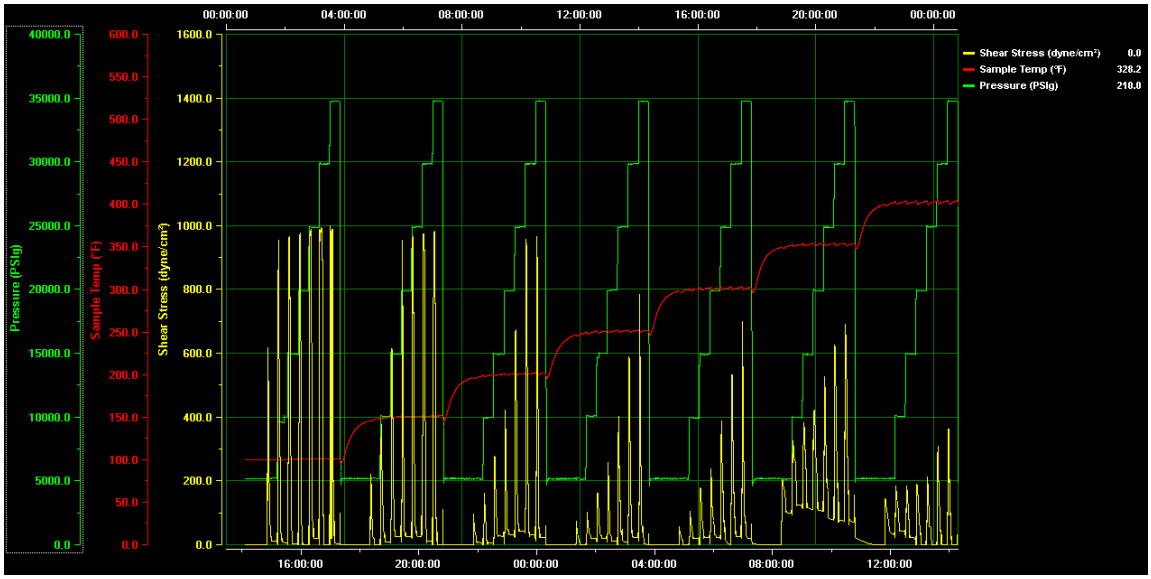

Figure 46 Shear Stress Results.

Figure 47 shows dial reading values have similar shear stress behavior.

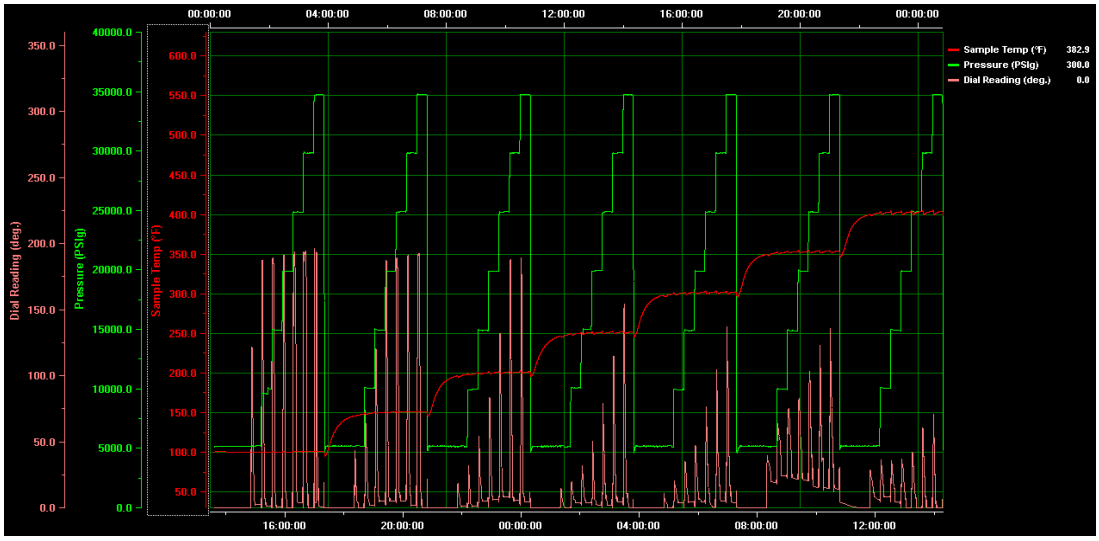

Figure 47 Dial Reading Results.

Figure 48 shows the viscosity behavior during the test it can be seen clearly that it increases at the failure point 350 °F.

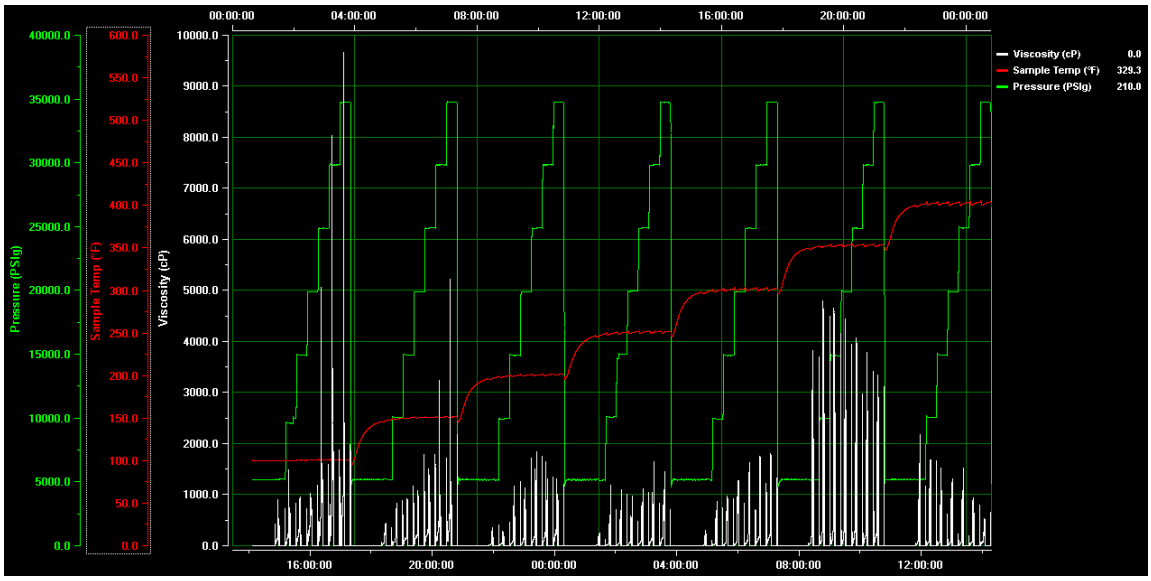

Figure 48 Viscosity Results.

Once the final results were obtained, the raw data was formatted by a macro by clicking the green button View Excel Report in the Main tab of Rheo 7000 Software Figure 49.

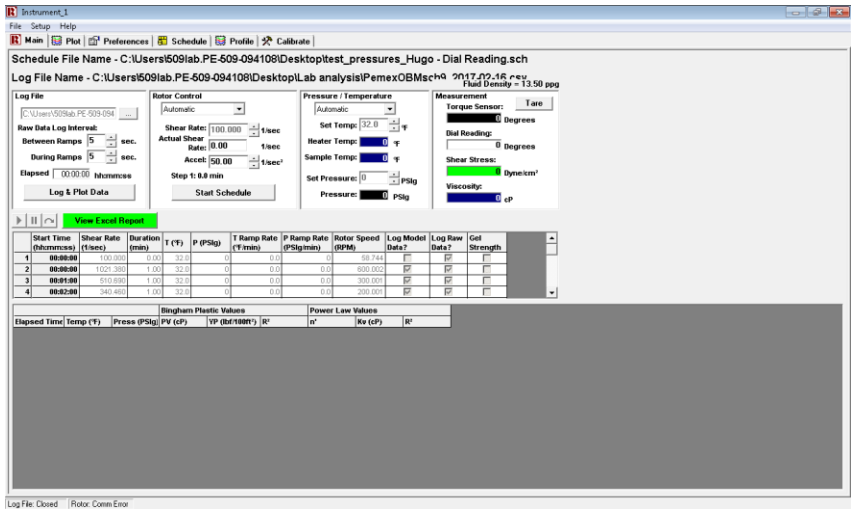

Figure 49 How to Access the Macro in Rheo Software

Getting the following Table 4:

Table 4 Formatted Final Results

Model 7600 XHPHT Rheometer

File Name: PemexOBMsch9_2017-02-13.csv
Schedule: C:\Users\509lab.PE-509-094108\Desktop\test_pressures_Pedro_e_Rafael_9.sch
Date: 2/13/2017
Time: 1:28:11 PM
Density: 13.50 ppg

Conditions				**RPM Readings @**									PV	YP
Start Time	**End Time**	**Temp (°F)**	**Pressure (PSI)**	**600**	**300**	**200**	**100**	**60**	**6**	**3**	**Initial gel**	10-min gel	(cP)	(lbf/100ft²)
1:25:01	1:43:18	100	5,203	122	97	66	38	25	6	5	4	9	61	15
1:50:19	2:04:37	100	9,679	187	137	110	54	38	8	7	5	9	93	22
2:11:38	2:25:56	100	14,932	188	185	152	101	55	12	9	3	9	93	47
2:32:57	2:47:15	101	19,895	189	191	190	125	94	12	7	2	13	88	66
2:54:16	3:08:36	101	24,871	190	192	193	181	124	17	13	14	17	78	88
3:15:41	3:29:54	101	29,844	191	193	194	195	175	27	18	13	20	68	107
3:37:00	3:51:18	101	34,764	4	4	4	194	194	39	24	16	21	-53	104

Table 4 Continued

Conditions				RPM Readings @									PV	YP
Start Time	End Time	Temp (°F)	Pressure (PSI)	600	300	200	100	60	6	3	Initial gel	10-min gel	(cP)	(lbf/100ft²)
4:58:23	5:12:41	147	5,208	44	38	28	16	10	5	4	3	4	21	8
5:19:42	5:34:00	149	10,067	73	63	46	25	20	8	7	7	10	35	14
5:41:06	5:55:24	150	14,951	120	105	78	41	28	9	9	7	13	59	21
6:02:30	6:16:43	150	19,894	187	147	113	54	39	9	8	8	16	94	24
6:23:49	6:38:07	151	24,889	188	182	143	93	50	12	11	11	19	94	43
6:45:14	6:59:31	151	29,846	189	191	182	118	76	13	10	7	19	90	60
7:06:32	7:20:50	151	34,758	190	192	193	148	108	16	12	9	24	83	77
8:27:58	8:42:11	197	5,178	19	14	11	8	6	2	2	2	4	8	4
8:49:17	9:03:35	198	9,935	32	25	22	15	9	3	3	3	5	15	7
9:10:41	9:24:54	200	14,911	54	45	34	22	17	8	7	6	9	24	13
9:32:00	9:46:18	200	19,893	82	71	53	33	24	9	9	8	10	38	18
9:53:24	10:07:37	200	24,877	132	110	84	46	31	13	13	11	13	63	24
10:14:43	10:29:01	201	29,846	188	138	109	55	37	8	8	9	12	93	23
10:36:08	10:50:20	201	34,767	188	176	129	83	47	10	9	8	13	95	37
11:57:29	12:11:42	247	5,184	15	10	7	5	4	2	2	2	1	6	3
12:18:49	12:33:06	249	10,073	20	16	13	11	9	6	6	7	5	7	8
12:40:13	12:54:25	250	15,023	32	26	23	16	11	7	6	7	6	13	10
13:01:32	13:15:50	250	19,955	50	42	32	19	12	6	6	6	5	24	10
13:22:56	13:37:09	251	24,902	78	62	47	28	18	8	8	11	8	37	14
13:44:15	13:58:33	251	29,844	115	94	63	38	24	8	8	10	9	56	17
14:05:39	14:19:52	251	34,746	154	116	93	48	33	11	11	14	8	75	22
15:27:01	15:41:13	298	5,181	11	8	7	5	4	3	3	3	1	4	4
15:48:19	16:02:37	300	9,940	21	17	15	12	11	7	7	5	5	7	9
16:09:44	16:24:01	300	14,910	35	30	27	19	15	10	10	6	6	13	14
16:31:04	16:45:16	301	19,890	47	41	34	24	20	13	13	8	7	18	18
16:52:23	17:06:41	301	24,891	76	61	49	33	27	15	14	12	8	32	21
17:13:47	17:28:00	301	29,841	104	88	64	41	32	17	17	13	13	46	26
17:35:06	17:49:24	301	34,762	137	109	91	51	39	18	18	15	14	62	30
18:56:55	19:11:13	350	5,146	40	38	36	34	34	31	28	23	22	5	34
19:18:15	19:32:32	352	9,966	64	61	57	53	52	48	40	28	27	10	51
19:39:39	19:53:57	352	14,914	75	73	68	59	55	47	43	28	28	15	54
20:00:58	20:15:16	353	19,895	82	80	74	59	54	45	44	28	28	20	54
20:22:22	20:36:40	353	24,888	104	97	86	61	54	40	40	32	32	34	52
20:43:41	20:57:59	353	29,846	120	106	96	62	54	38	38	28	32	43	50
21:05:05	21:19:23	353	34,772	133	111	102	66	54	33	33	28	33	52	48
22:26:28	22:40:40	400	5,198	28	25	23	21	19	17	14	13	8	6	18
22:47:47	23:02:05	402	10,059	36	32	30	26	23	18	14	10	10	10	21
23:09:11	23:23:24	402	14,932	37	34	30	26	21	16	15	7	6	11	20
23:30:30	23:44:48	402	19,893	37	34	31	24	20	13	12	8	3	12	18
23:51:54	0:06:07	402	24,890	42	38	32	24	19	11	11	9	2	16	17
0:13:13	0:27:31	402	29,846	60	46	39	24	20	9	9	7	9	26	15

If data is available at 300 and 600 RPM, this macro uses the 600-300 RPM equations for PV and YP.

$$\mathbf{PV = 600\ RPM - 300\ RPM} \tag{20}$$

$$\mathbf{YP = 300RPM - PV} \tag{21}$$

Otherwise, it uses the reported value by viscometer, which is based on a linear regression as was explained with 3.4 Experimental Schedule equations.

Figure 50 shows the 10 sec. gel strength performance, at 350 °F it goes over the average values, furthermore the gel strength increases with pressure.

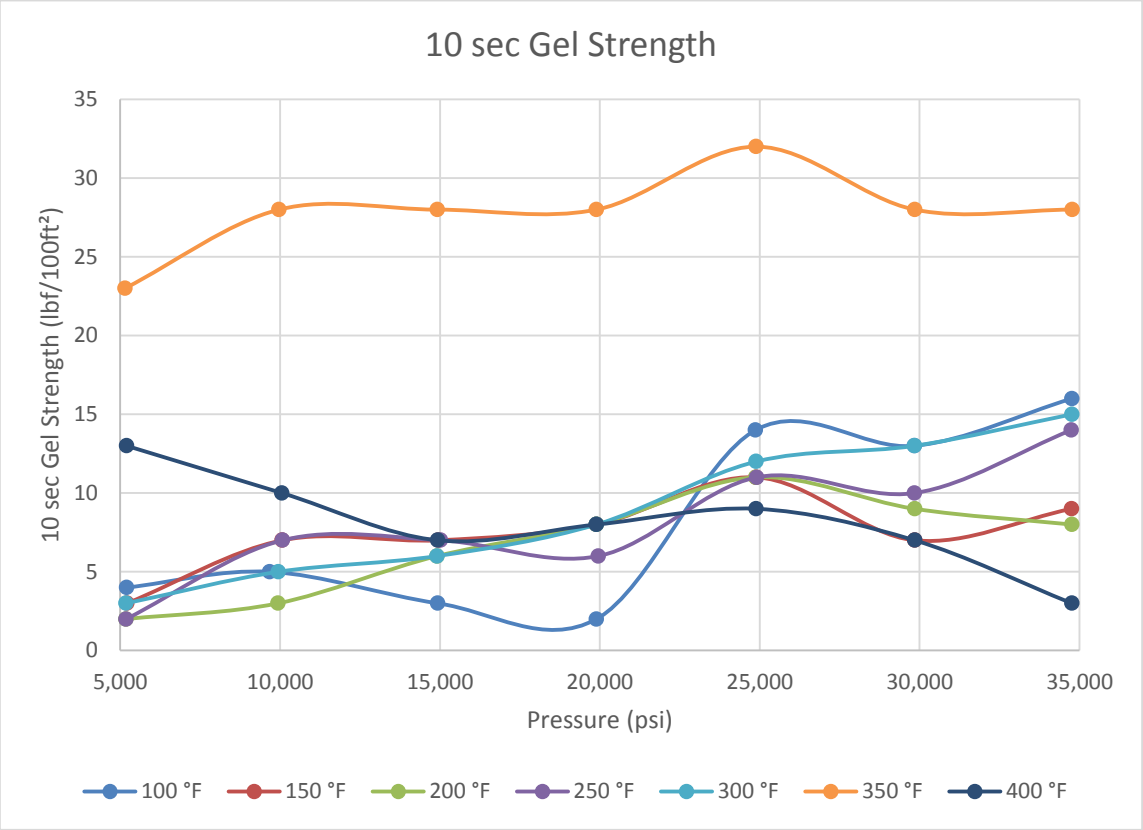

Figure 50 10 sec Gel Strength

Figure 51 shows the 10 min. gel strength performance, at 350 °F it goes over the average values, moreover the gel strength increases with pressure, and decreases with temperature.

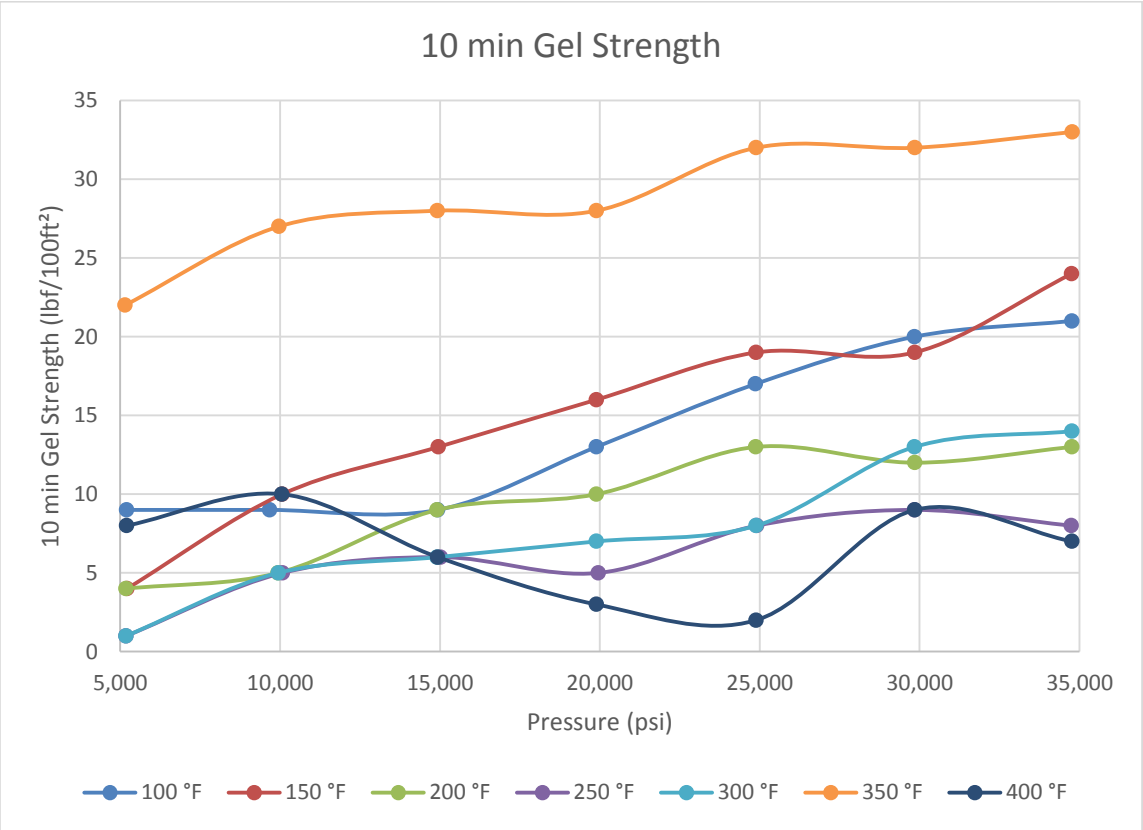

Figure 51 10 min Gel Strength

Figure 52 shows the plastic viscosity performance, at 100 °F it has a different behavior from the average, since it goes below 0, due to it reaches the shear stress range limit. For other temperatures, plastic viscosity increases exponentially with pressure and decreases with temperature.

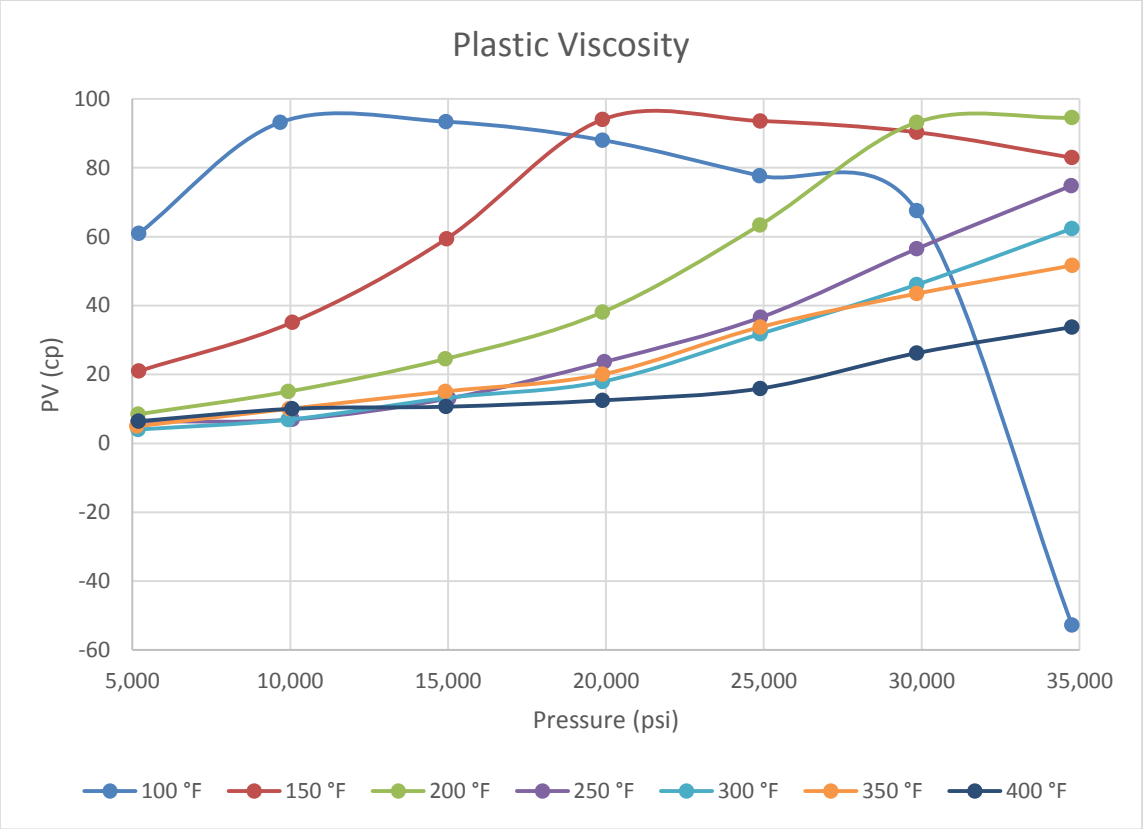

Figure 52 Plastic Viscosity

Figure 53 shows the YP performance, is greatly increased at low temperatures and high pressures, at 350 °F it goes out of average behavior. It has an increasing behavior with pressure for 100, 150, 200, 250, 300 °F, nevertheless for 350 °F and 400 °F it decreases with pressure.

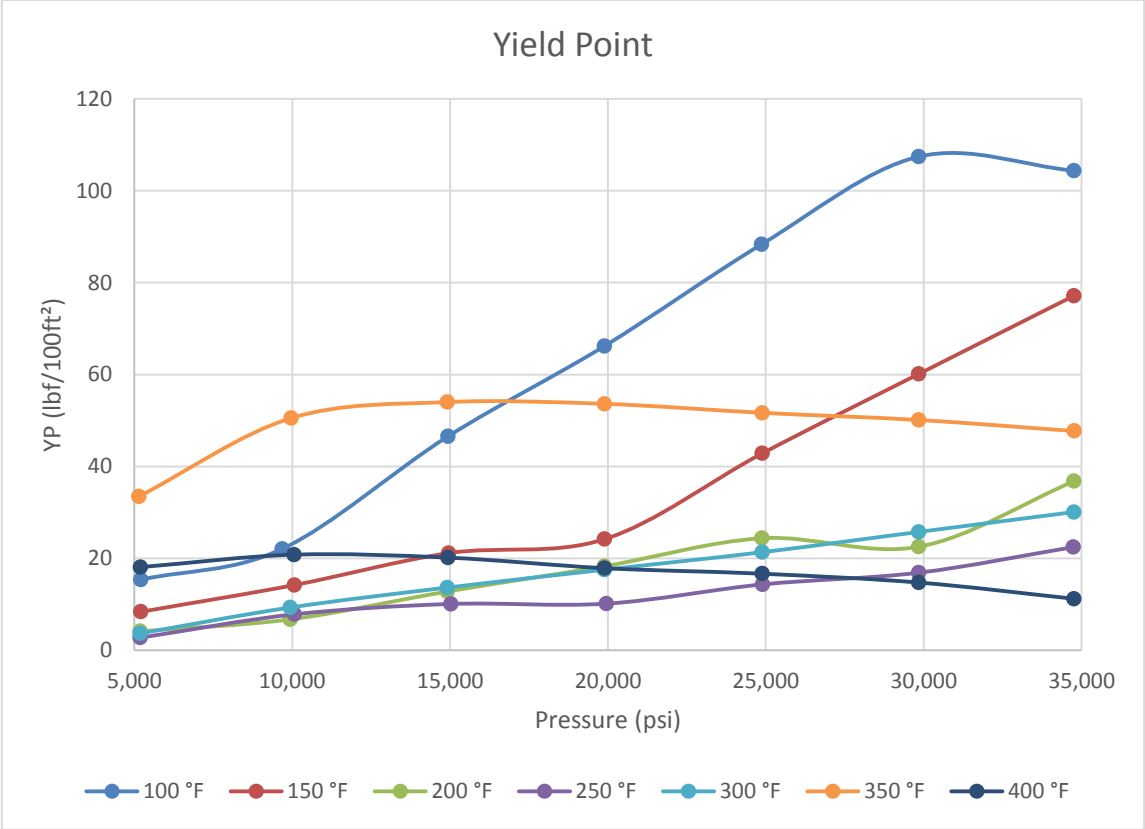

Figure 53 Yield Point

It was decided to plot the final results in constant temperature varying pressure and constant pressure varying temperature graphs, as it is shown in the next pages.

4.1 Constant Temperature Varying Pressure

Figure 54, shows the rheological behavior at a constant temperature of 100 °F for increments of pressure every 5,000 psi, it is noticed that shear stress increases as pressure increases, thus it means is more difficult to move the fluid as the pressure increases, while the viscosity is the slope of the curves therefore the viscosity is directly proportional to the pressure. At high pressures the shear stress increases faster at the

beginning, then it keeps constant, since it reaches the shear stress limit, this value is lower than the specified in the manual, maybe in view of the fact that the spring is loose, particularly at 35,000 psi after 100 RPM, it can be seen that the viscometer has a reading problem, owing to the fact this erratic behavior has been happened in all the tests run, as a result of the reading of the viscometer goes far beyond the allowed range, due to the spring used, additionally it is not likely that anyone would experience this extreme pressures at low temperatures.

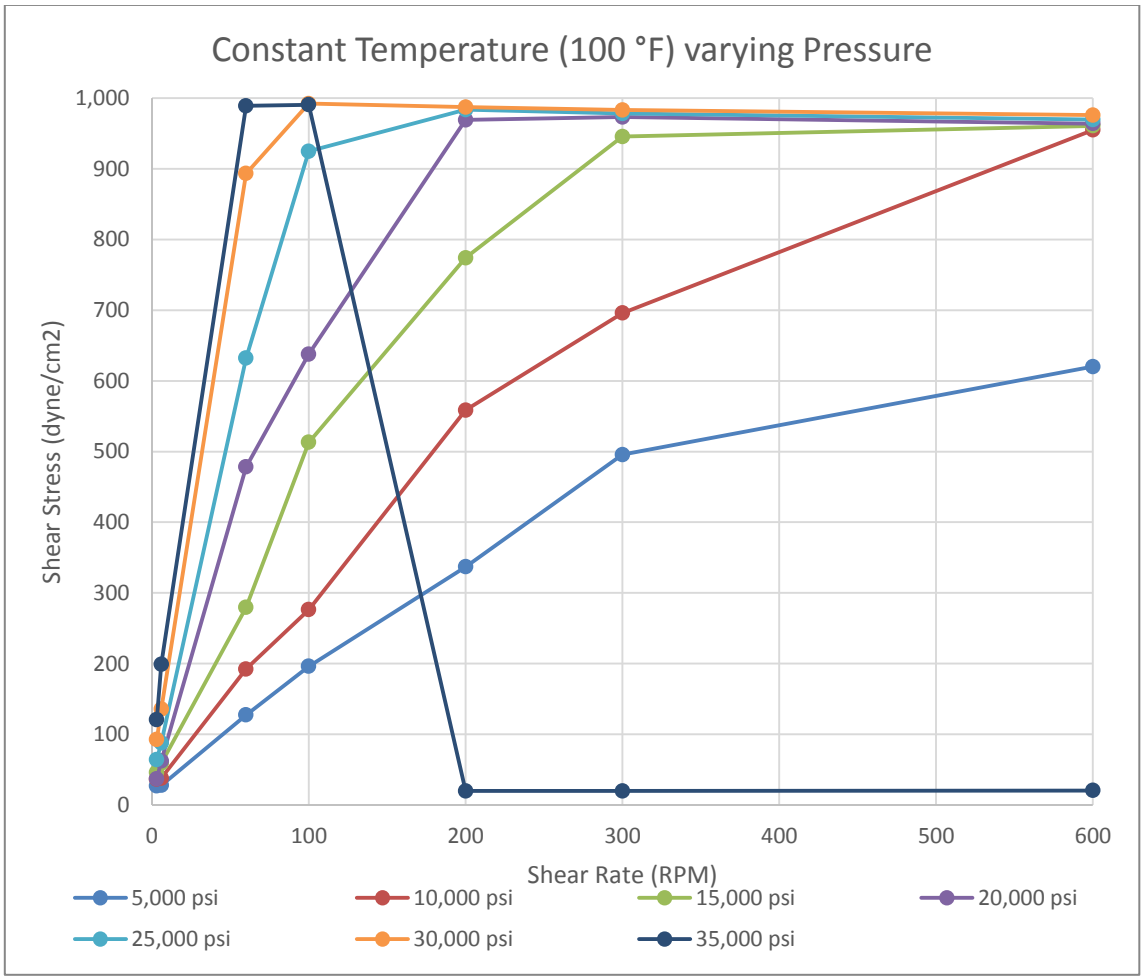

Figure 54 Constant Temperature (100 °F) Varying Pressure

Figure 55, shows a similar behavior, but now the shear stress is lower due to the sample is being heated, therefore the viscosity and YP are lower.

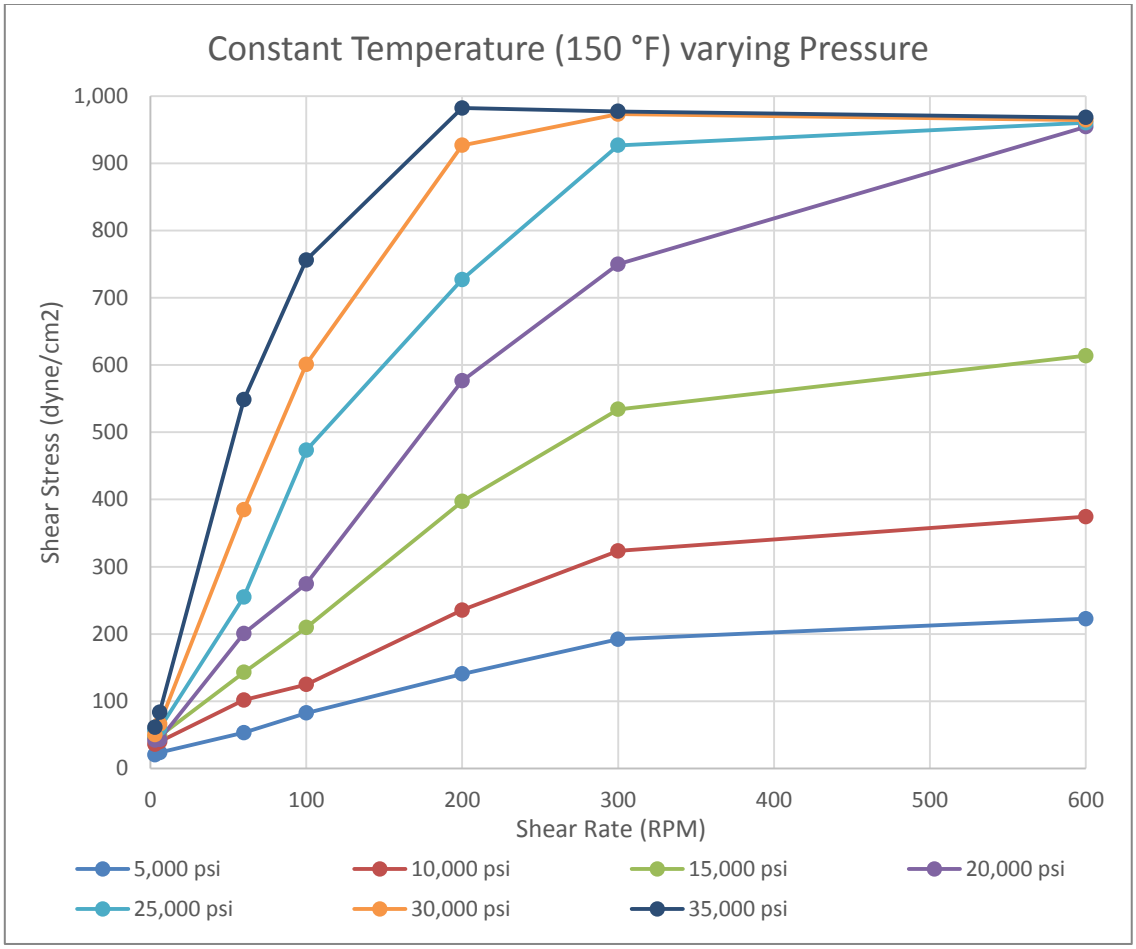

Figure 55 Constant Temperature (150 °F) Varying Pressure

In Figure 56, almost every value fit the shear stress range, except 35,000 psi; at higher pressures the shear stress changes are bigger as shear rate increases.

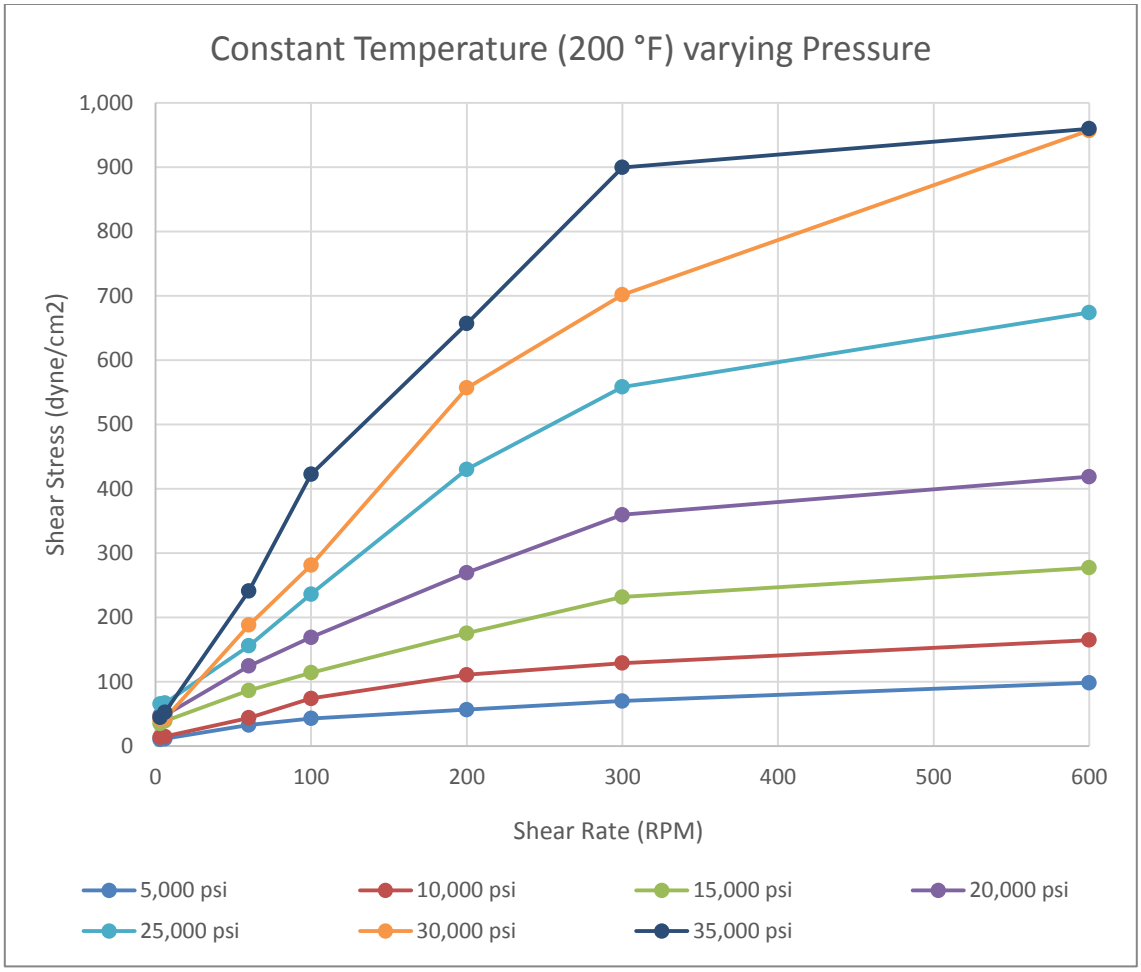

Figure 56 Constant Temperature (200 °F) Varying Pressure

In final results CSV file, can be seen that Bingham Plastic model fits better the behavior at 5,000 and 10,000 psi than Power Law model, because the R^2 value in Bingham Plastic is closer to 1 than in Power Law Figure 57.

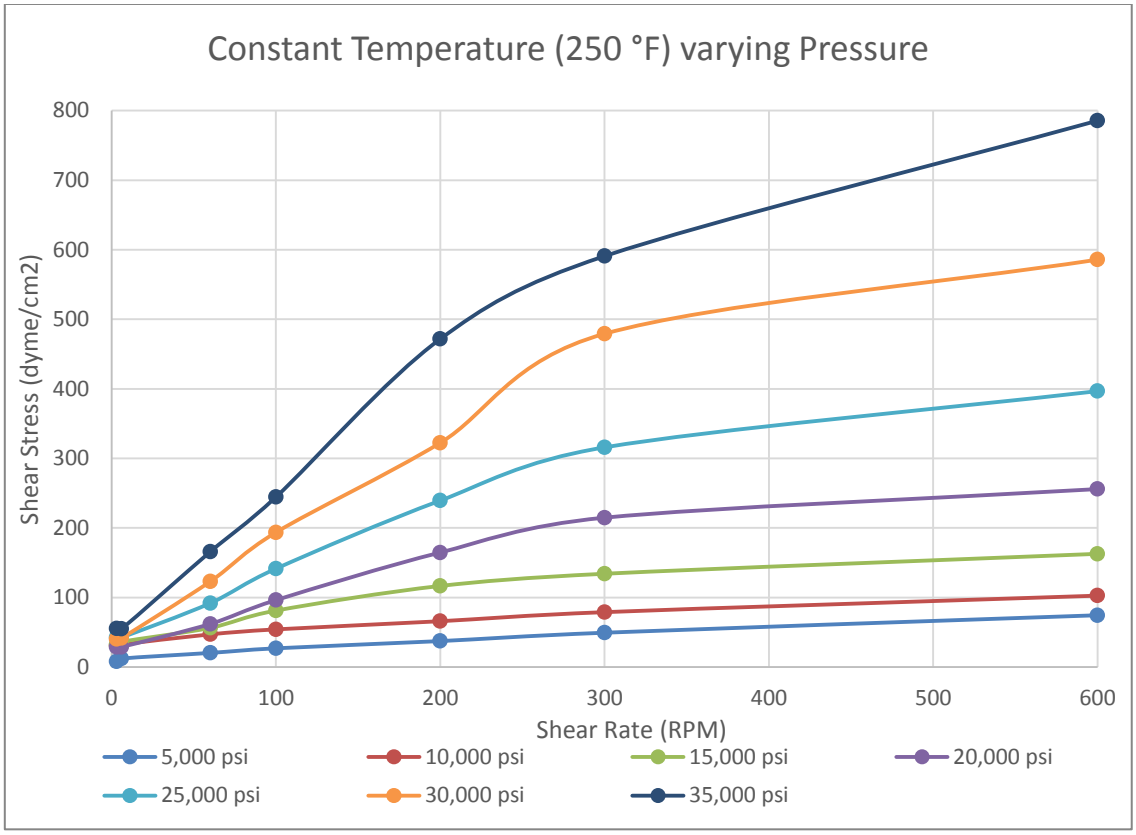

Figure 57 Constant Temperature (250 °F) Varying Pressure

In Figure 58, Bingham Plastic fits better the behavior at 5,000 psi than Power Law. The changes in shear stress are bigger for higher pressures.

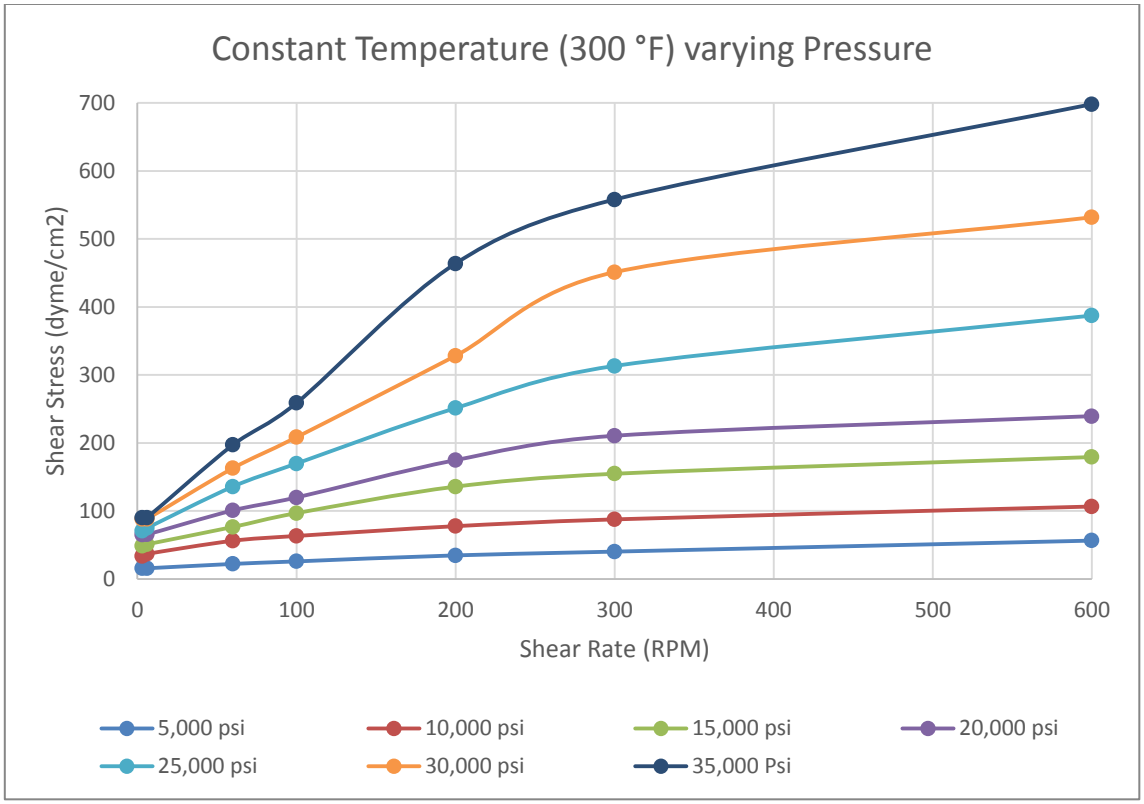

Figure 58 Constant Temperature (300 °F) Varying Pressure

In Figure 59, at 350 °F the YP and shear stress before 60 RPM are low for higher pressures, after that, shear stress is high for higher pressures, hence the sample has failed.

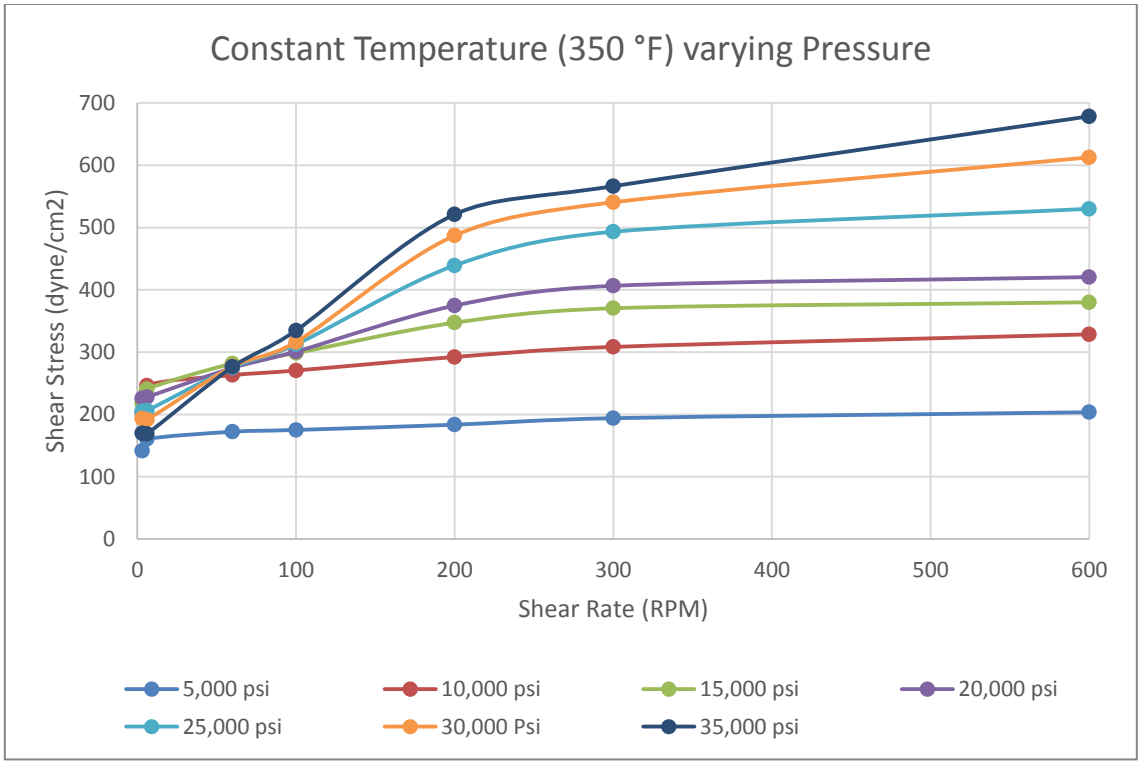

Figure 59 Constant Temperature (350 °F) Varying Pressure

Owing to the sample has failed, the same behavior can be seen in Figure 60, YP and shear stress is low for higher pressures, but after 100 RPM shear stress become high. Thus, for the highest temperature, the lowest viscosity is seen.

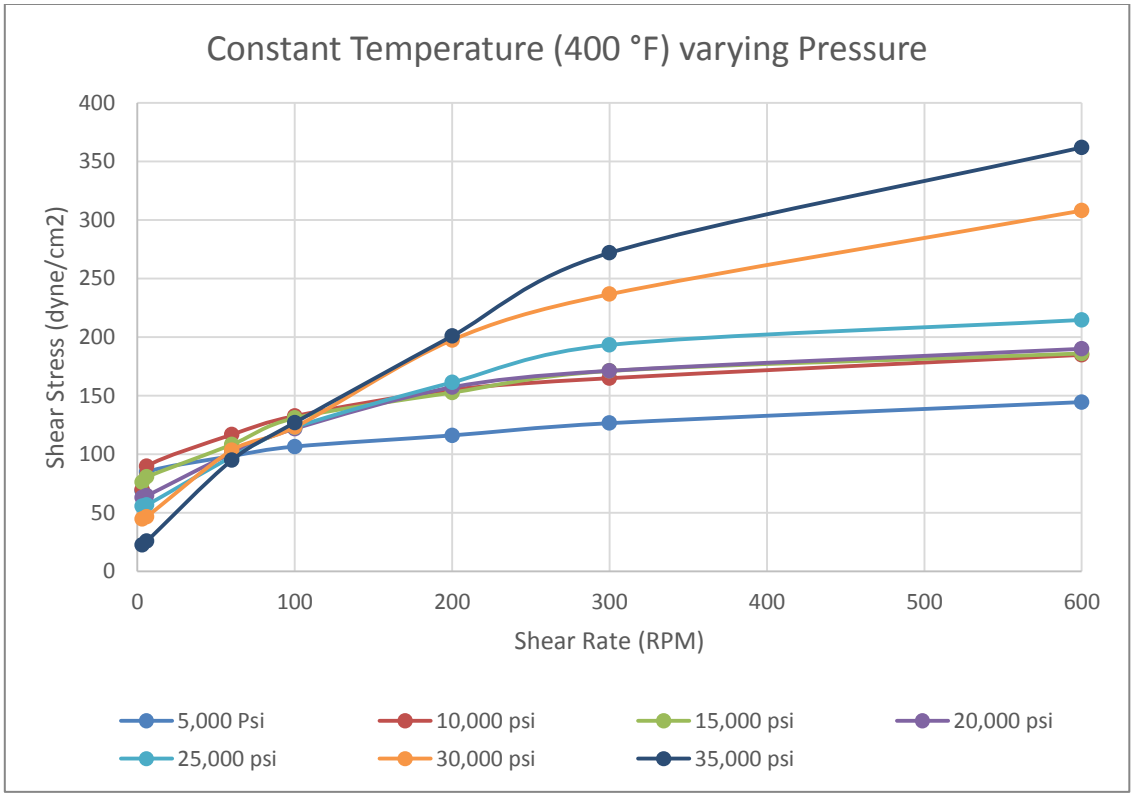

Figure 60 Constant Temperature (400 °F) Varying Pressure

4.2 Constant Pressure Varying Temperature

The results keeping pressure constant, at different temperatures follows. Shear stress, YP and viscosity decreases as temperature increases, so they are inversely proportional to temperature. The effect of pressure is more predominant than temperature. At 350 and 400 °F the shear stress is higher than the expected behavior Figure 61.

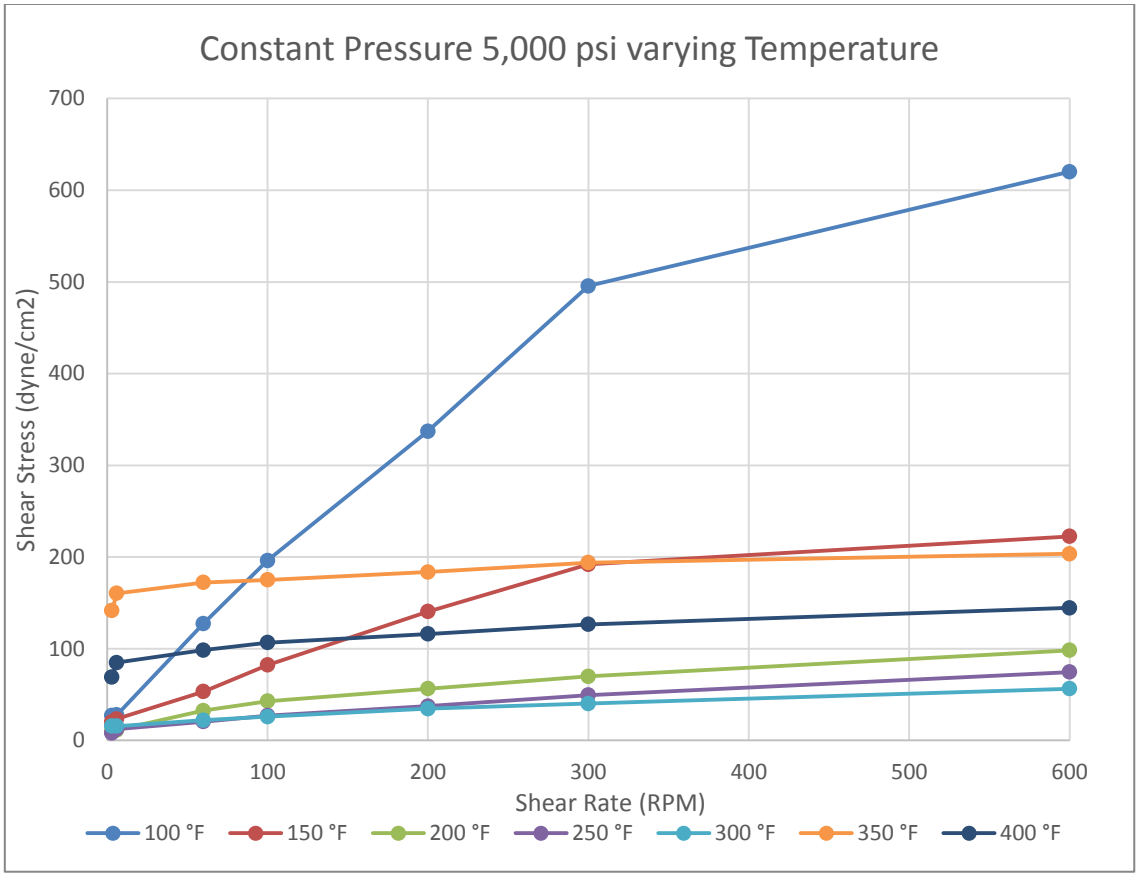

Figure 61 Constant Pressure 5,000 psi Varying Temperature

At 100 and 150 °F the shear stress changes are more noticeable, so viscosity for 100 and 150 °F is high, but for the other temperatures viscosity is low. At 300, 350 and 400 °F the shear stress is higher than the expected behavior Figure 62.

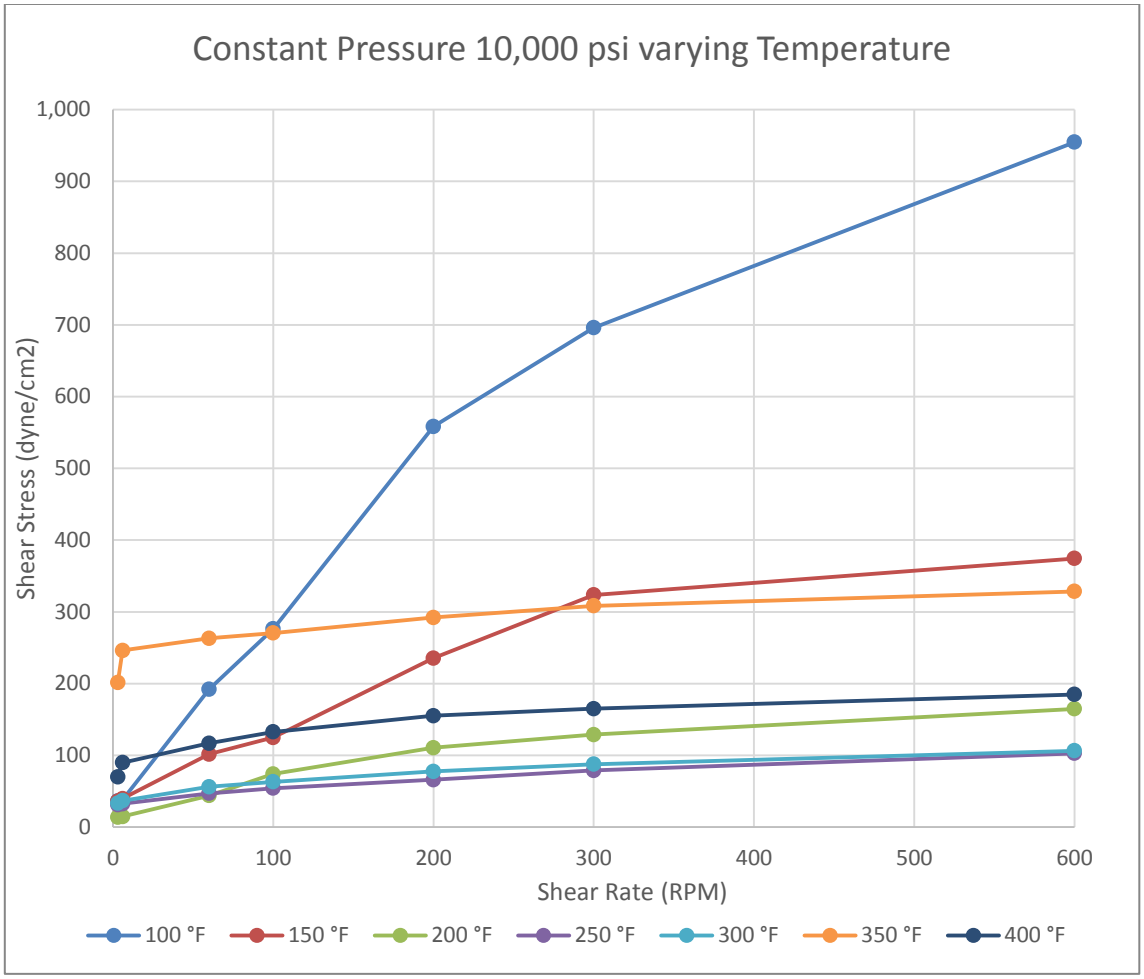

Figure 62 Constant Pressure 10,000 psi Varying Temperature

At 100 °F the shear stress has reached the viscometer range. At 300, 350 and 400 °F the shear stress is higher than the expected behavior Figure 63.

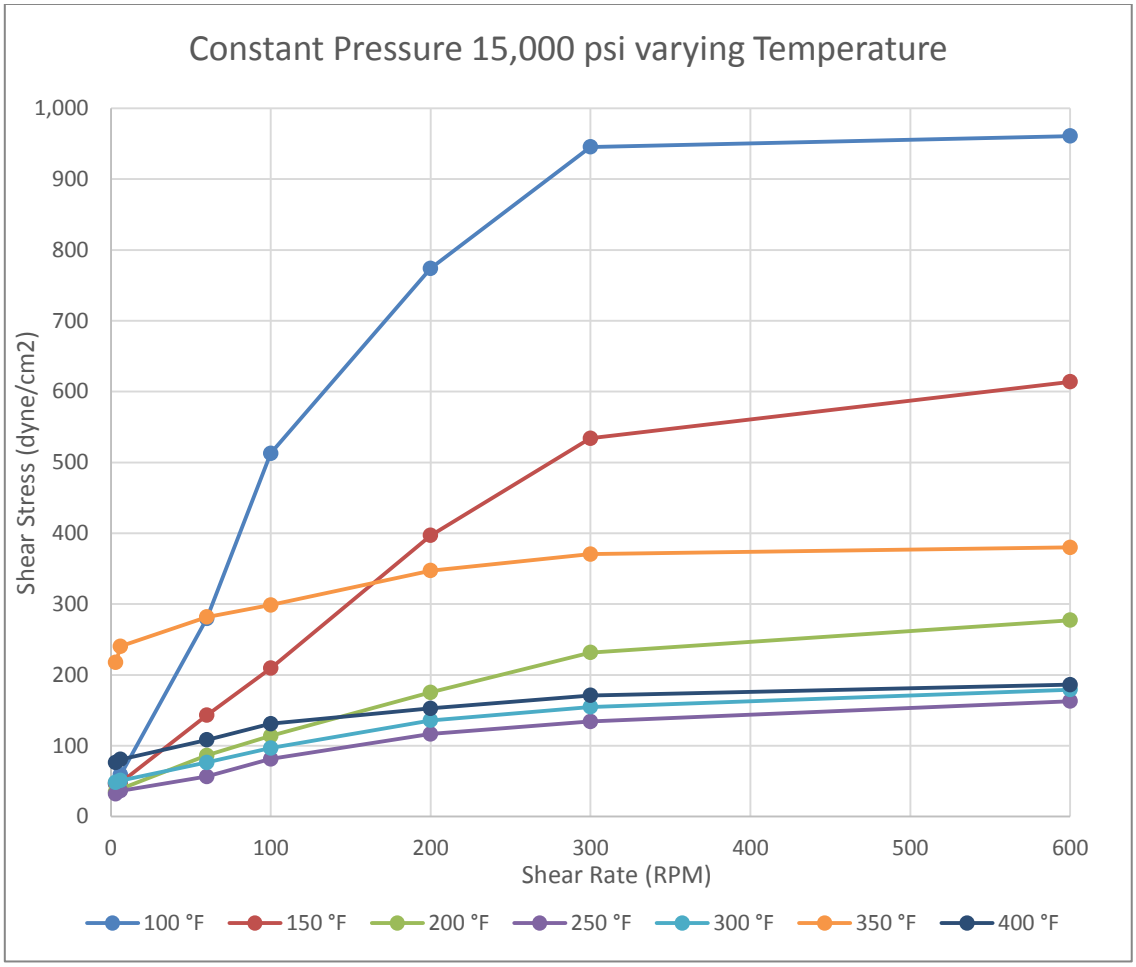

Figure 63 Constant Pressure 15,000 psi Varying Temperature

In Figure 64, at 300 and 350 °F the shear stress is higher than the expected behavior.

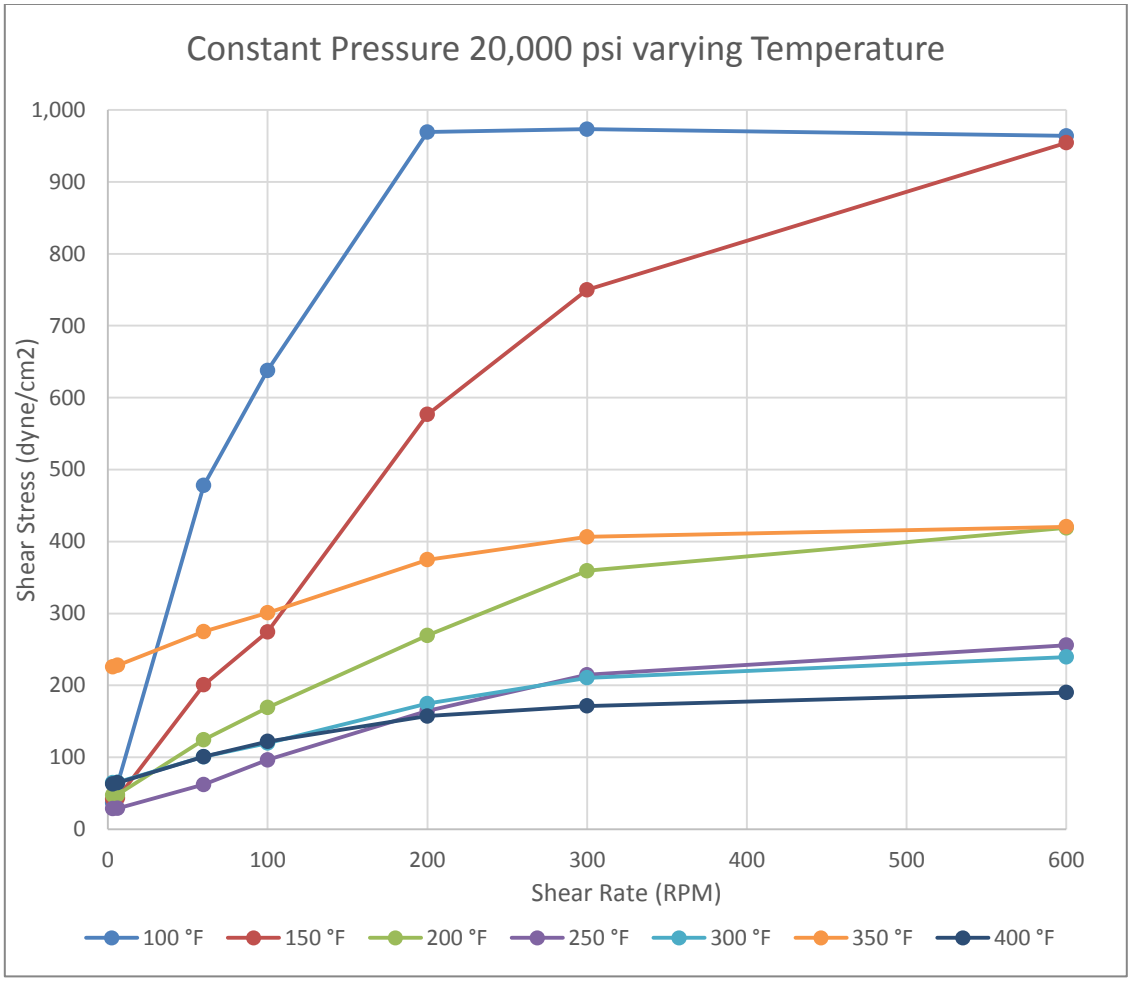

Figure 64 Constant Pressure 20,000 psi Varying Temperature

In Figure 65, at 350 °F the shear stress is higher than the expected behavior.

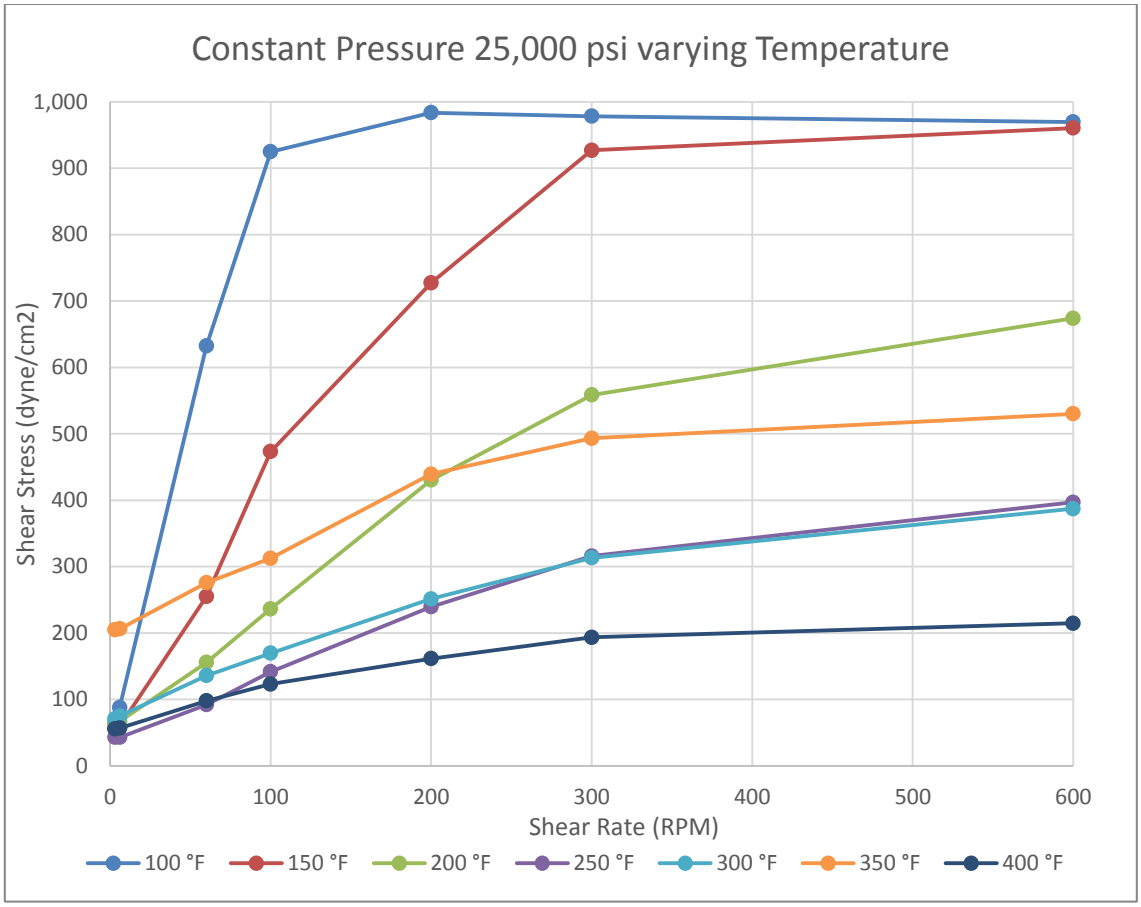

Figure 65 Constant Pressure 25,000 psi Varying Temperature

In Figure 66, at 350 °F the shear stress and the YP at 300 °F are higher than the expected behavior.

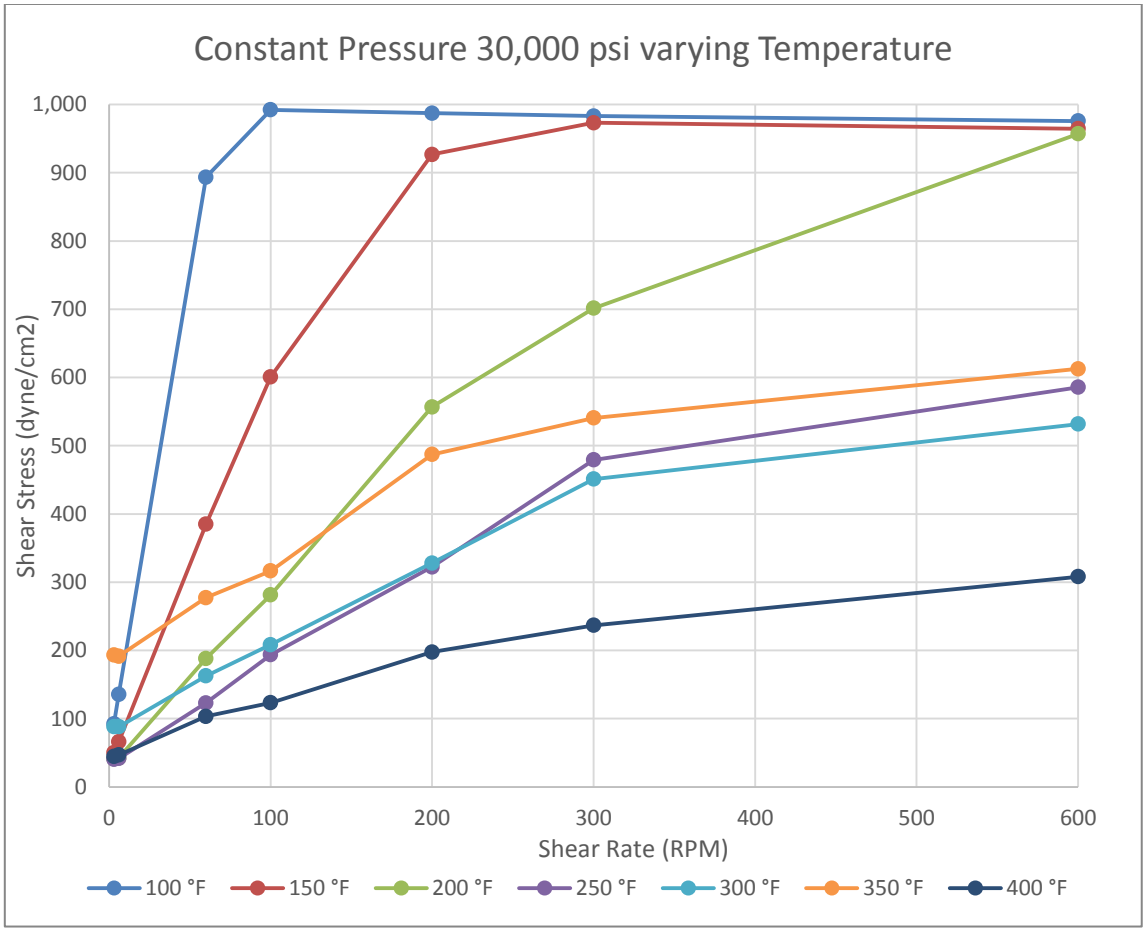

Figure 66 Constant Pressure 30,000 psi Varying Temperature

In Figure 67, the shear stress changes are more significant, so the changes in viscosity are bigger, as temperature arises viscosity reduces, therefore viscosity is inversely proportional to temperature. At 100 °F after 100 RPM it was an instrument error as mentioned before.

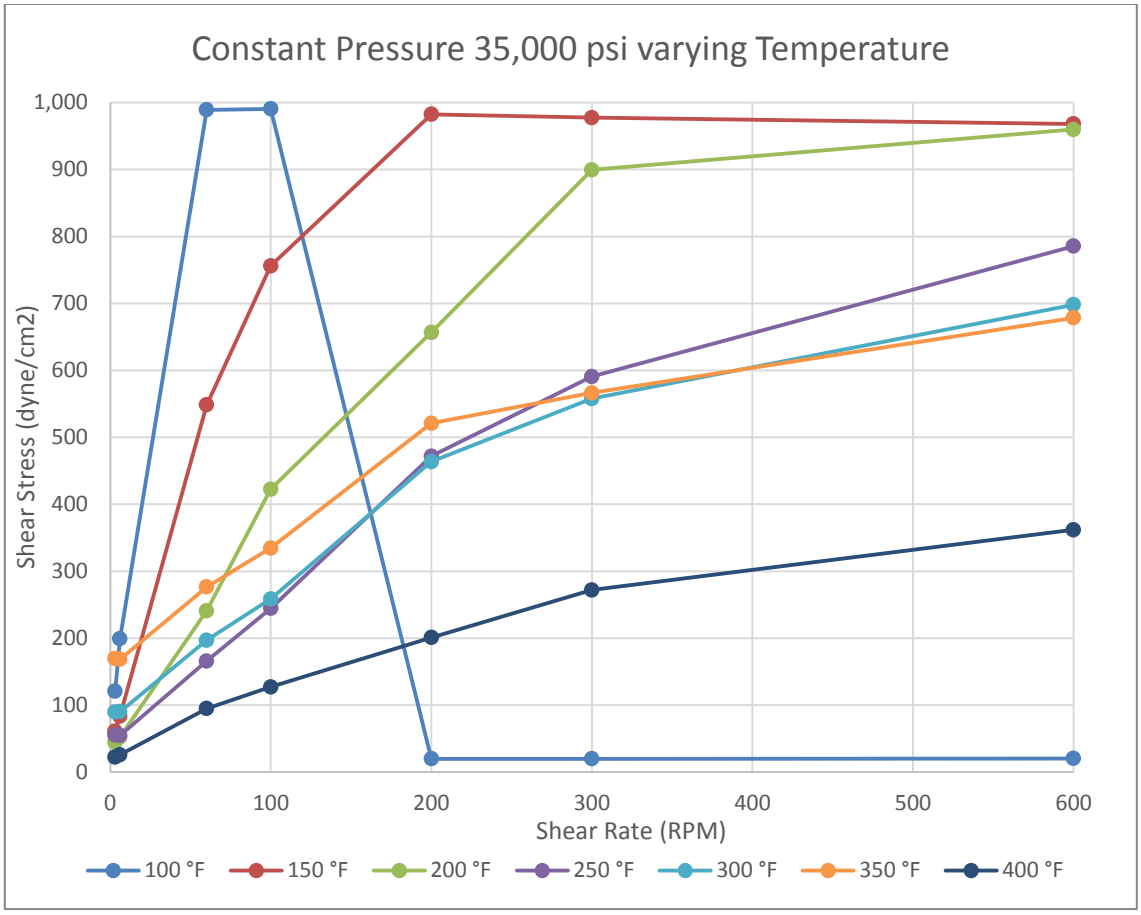

Figure 67 Constant Pressure 35,000 psi Varying Temperature

At constant temperatures, the sample failure can be identified when the shear stress curves crosses among them.

At constant pressures, the sample failure can be identified when the shear stress curve increases as temperature increases; the tendency must be that the shear stress curve decreases as temperature increases.

According to these parameters, it seems that the sample has failed at 350 °F. The rheological behavior of the sample is pseudoplastic. The pressure effect is more noticeable at low temperatures.

The water test was run, yet a Newtonian behavior was just performed at 5,000, 10,000 and 15,000 psi, above these pressures an anomalous behavior was performed, due to as more DURATHERM oil is needed to achieve the pressure, it mixes with the sample.

CHAPTER V

CONCLUSIONS, RECOMMENDATIONS AND FUTURE WORK

Throughout the performance of these tests, it is necessary to pay close attention to the spring module assembly, as it is the part that gave the dial reading lectures and hence the shear stress lectures and it is very sensitive to a loose spring and if the pivot is not placed correctly the lectures will be very high, also the screw has to be set in the flat part of the shaft of the bob.

The rheogram´s curves fit 2nd polynomial functions very well, especially at constant temperature. The R-squared values are all between 0.95 and 0.99, until the temperature hits 300 °F.

In summary, it is necessary to continue studying the rheological properties of the drilling fluids at xHPHT conditions (300 to 600 °F and 20,000 to 40,000 psi), because there is little information. The main focus of this research is to study the rheological behavior of an OBM sample at these extreme conditions. In future research work, it would be interesting to evaluate the performance of other fluids, for example by getting a formate brine sample.

Currently another research is being done for adapting the viscometer to simulate gas influx in order to avoid the mixture problem, by constructing an extreme HPHT PVT cell to have the ability to measure properties of drilling fluids, reservoir gasses, and its solubility in drilling fluids for conditions equivalent to the Model 7600 HPHT Viscometer. The goal is then to inject the gas laden drilling fluid into the Model 7600

HPHT Viscometer to determine the effect of the gas on the rheological properties of drilling fluids. This will allow developing an xHPHT gas kick behavior simulator.

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