THE USE OF WBM TO IMPROVE ROP IN HTHP/HARD ROCK ENVIRONMENTS

A Thesis

by

ANDREW PAUL KRAUSSMAN

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

MASTER OF SCIENCE

May 2011

Major Subject: Petroleum Engineering

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Committee Members, Ahmad Ghassemi
Judith Chester
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ABSTRACT

The Use of WBM to Improve ROP in HTHP/Hard Rock Environments. (May 2011)

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Chair of Advisory Committee: Dr. Fredrick E. Beck

Modern day oil and gas well costs are driven by drilling performance as time becomes the dominant capital expense source. The ability to lower drilling costs becomes paramount when tight economic margins and high uncertainties/risk exist. Rate of Penetration (ROP) decreases drastically in ultra deep formations, and substantial time is spent drilling the deepest section of these wells. Therefore, significant cost savings may be obtained through an improvement in penetration rate in deep formations. This thesis shows that in HTHP (High Temperature High Pressure) hard shale/sand environments that PDC (Polycrystalline Diamond Compact) bits paired with water based mud (WBM) experience 88% improvement in penetration rate than those paired with oil based mud. With this improvement in drilling rate, well costs can be substantially reduced making future ultra-deep hydrocarbon accumulations economically producible. Also observed was a drastic decrease in penetration rate in PDC bits with oil base mud which led to the use of diamond impreg bits, as the water base with PDC still maintained respectable penetration rates. The conventional penetration rate controls are still applicable in this case, but there exists a fundamental difference between the rock/fluid interactions of each mud type. Bit type, operating conditions, formation characteristics, and bit

hydraulics are shown to not be the dominant influencing factor of this performance trend. The water base fluids examined have higher filtrate rates than the oil base fluids. However, a consistent data set of increasing filtrate rate corresponding to increasing penetration rate cannot be derived. Therefore filtration characteristics remain as a possible and partial influencing factor behind this data. Future experimental research is needed to confirm or disprove this theory. At this time the actual cause of this behavior is unknown, however the trend has been established showing water base drilling fluids performance versus oil base in the HTHP/hard rock environment.

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CHAPTER I

INTRODUCTION AND BACKGROUND

Drilling Costs and ROP Controls

Well costs are dictated by an array of sources, drilling costs are a significant contributor to the cost of modern day oil & gas wells. Drilling costs are driven primarily by time; as drilling rigs are usually leased on a day rate. Other drilling costs can include wireline services, drilling fluids, cementing services, and raw materials. Total well time is broken down into several categories such as drilling, tripping, reaming, nipple up/down, BOP testing, rig maintenance and repair, cementing, wireline, hole conditioning, etc. In many cases actual drilling time (IADC code 2) accounts for a significant percentage of the total. Drilling time is dictated by the rate of penetration or ROP, usually expressed in feet per hour (ft/hr) which is the physical speed that the drill bit is traveling through the rock formations. The general accepted controls on ROP are[1]:

- Bit type
- Formation characteristics
- Drilling fluid (mud) properties
- Operating conditions
- Bit wear
- Bit hydraulics

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

Significant research has been performed in the past investigating these properties with a common goal of increasing ROP. These factors can be separated into controllable and un-controllable factors. The controllable factors are bit type, mud properties, operating conditions, and bit hydraulics. These factors are considered controllable as they can, for the most part, be manipulated by drilling personnel. Formation characteristics and bit wear are generally outside the control of the drilling rig. Scientific experimental procedures usually consist of holding certain parameters constant while manipulating a variable then observing the result. For example, if a certain mud property is to be examined all other conditions (bit type, formation, operating conditions) must remain constant for the result to be meaningful. Most research involving ROP has been performed following this procedure, thus common trends of the ROP controls have been discovered. However, manipulation of one or more of the controls can have variable effects on actual ROP. A good drilling program would incorporate all of these controls to establish a highly efficient low-cost program.

Bit type is often selected by the drilling engineer and is selected to achieve a specific goal. There are several different types of bits that are commonly used in industry today. They include: tooth bits, insert bits, diamond impregnated, drag bits, rolling cutter bits, and polycrystalline diamond compact (PDC) bits (see Figure 1). Bits are selected to penetrate specific formations or perform under particular circumstances. Formations are characterized as soft, medium-soft, medium, medium-hard, and hard. The International

Association of Drilling Contractors (IADC) codes PDC bits from D1-D5 which corresponds to the formation hardness. For example a soft formation would call for a D1 bit and a hard would call for a D5 PDC bit. Roller cutter and drag bits have a similar classification system. The abrasiveness of the formation must also be taken into account. As some formations are highly abrasive and can cause bit wear faster than a less abrasive formation. A similar IADC bit classification code for abrasion resistance also exists and specific bit models are classified on this basis.

Bit selection is also based on the bit's abilities and characteristics. Bit performance is often judged by these characteristics: durability, steerability, stability, adaptability, and ROP/drillability. Durability references the bit's ability to resist damage and wear. Steerability is the bits ability to perform in non-vertical wells. Stability refers to the bit's cutting characteristic and how it affects wellbore condition. Adaptability is the bit's ability to perform under a variety of conditions. ROP/drillability refers to the aggressiveness of the bit and the speed it is expected to drill at. In general light set PDC bits have excellent ROP, good durability in soft rocks, moderate stability, variable steerability, and poor adaptability characteristics. Heavy set PDC bits have limited ROP, excellent durability, variable stability, good steerability, and poor (better than light set) adaptability characteristics. Tooth bits have good ROP, variable durability, excellent stability & steerability, and excellent adaptability. However tooth bits are highly susceptible to bit-balling (discussed later) which can lead to a decrease in performance.

Light set insert bits experience average ROP, good durability & stability, very good steerability, and good adaptability. Heavy set insert bits experience low ROP, excellent durability, reasonable steerability, good stability, and variable adaptability. Heavy set insert bits are usually selected to penetrate hard/abrasive formations but are also susceptible to bit balling. Bit characteristics are a give/take relationship for example; a highly durable bit will have more blades/cutters which leads to a decrease in ROP. A bit that shows "excellent" performance in all of these characteristics does not exist. Therefore, the selection of the optimal bit is dependent on the desired task and must be evaluated on a case by case basis.

Figure 1: Various Rotary Drilling Bits From Left: Tri-Cone Insert Bit, Diamond Impreg Bit, Tooth Bit, and PDC Bit. (National Oilwell Varco Downhole *Drill Bit Basics,* October 2010)

ROP, bit life, and bit cost are the primary factors in economic bit selection. As stated before bits are designed to operate in particular rock environments which can lead to optimal bit life and ROP. However some high performance bits can be very costly so economic considerations must be made before any bit run. For a bit run to be economically efficient the cost per unit depth (CPUD) must be minimized. The long standing CPUD equation is[2]:

$$CPUD = C_b + C_r(t_b + t_t)/\Delta D$$

where C_b is the bit cost, C_r is the rig cost per unit time, t_b is sum of drilling time for a bit, t_t is trip time, and ΔD is the interval of depth. ΔD can also be expressed by multiplying ROP by t_b thus this equation can be re-written in terms of ROP. Thus an increase in ROP for a given bit will result in a lower CPUD, so the improvement of bit performance can have a direct effect on cost drilling cost reduction[2].

Formation characteristics such as rock strength, permeability, and mineralogy have a significant impact on ROP but are practically an un-controllable force. These properties will vary drastically depending on the lithology of the formations to be drilled in a particular well. Elastic limit and ultimate strength of the rock are the most important mechanical characteristics affecting ROP. Drilling through rock is essentially causing the rock to fail; therefore a mathematical model is needed to predict failure. There are several different models used to predict the failure of rock, Mohr-Coulomb failure criteria is often used to describe formation strength. The Mohr-Coulomb theory is a mathematical model that predicts the response of brittle materials to a particular loading scenario. The model relates normal and shear stresses and provides a "failure envelope" that will predict failure of the material under a particular stress state. Figure 2 shows a Mohr circle which is used to plot shear versus normal stresses based on a loading in arbitrary x and y directions[3].

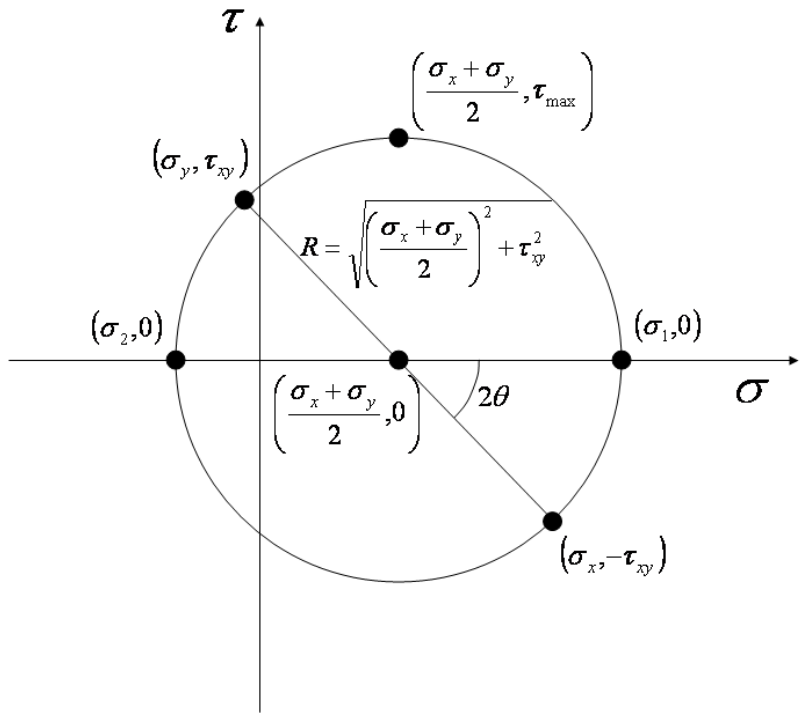

Figure 2: Shows Example Mohr Circle

(http://hades.mech.northwestern.edu/index.php/Mohr's_Circle, October 2010)

The failure envelope is generated by creating a linear relationship between shear (τ) and normal stress (σ_n) along with an angle of internal friction (φ) and cohesion strength (σ_c). This line will touch tangent to corresponding Mohr circles under different stress states.

$$\tau = \sigma_n \tan\varphi + \sigma_c$$

Shear strength is an important characteristic for influencing ROP. As bit teeth penetrate rock and turn they create a crater like cut into the rock. This failure is considered shear failure and the initial penetration of the tooth into the rock is dependent on the compressive strength of the rock. Therefore when drilling rocks with higher compressive and shear strengths, penetration rate will decrease[1].

Permeability can also have an effect on ROP. Mud filtrate can penetrate into permeable rocks ahead of the bit equalizing differential pressure that acts on individual rock chips that are formed by the bit cutters. With less pressure acting downward on the rock cuttings crater formation by the bit is more elastic thus increasing penetration rate. Further discussion of mud filtrate is presented later[1].

Mineralogy of the formation is also a factor affecting ROP. Rocks that contain hard abrasive minerals can dull the cutters on a bit at a higher rate than softer rocks similar to a grinding wheel against steel. Generally tri-cone diamond impreg bits are run at high WOB through abrasive formations. Rocks that are high in clay content, such as most shales, can also affect penetration rate. The clay particles can differentially stick to the bit (bit balling) and BHA components thus decreasing ROP. Further discussion of bit balling will be presented later.

Mud properties that have an effect on ROP are density, rheology, filtration characteristics, solid component, and chemical composition[1]. In general mud density is dictated by well control requirements i.e. a certain mud weight is needed to achieve a bottom hole pressure (BHP) that meets or exceeds the pore pressure of the rock for a balanced or overbalanced scenario. This pressure balance is needed to avoid taking kicks (formation fluid entering the wellbore) and possible blowout (un-controlled release of formation fluids). The bottom hole pressure is given by the following equation[1]:

$$BHP = 0.052(MW)(TVD)$$

where MW is the mud weight in pounds per gallon (PPG) and TVD is the total vertical depth of the well in feet. If BHP is higher than pore pressure, an overbalanced drilling situation is created. Penetration rate tends to decrease with increasing mud weight due to an increase in BHP. Therefore in HTHP environments where BHP's can be above 20,000psi the ROP tends to decrease thus driving research in this area. Underbalanced drilling is the process of drilling where wellbore pressure is lower than formation pore pressure. This allows the formation fluid to flow into the wellbore during drilling. Advantages of underbalanced drilling is an increase in ROP, decrease in formation damage, decrease of lost circulation, and decrease in differential sticking (drill pipe sticking to side of wellbore). Underbalanced drilling is also more expensive and potentially more dangerous than conventional overbalanced drilling. Therefore, underbalanced drilling does not represent a conservative approach to increasing penetration rate, but is an option.

Several properties of mud including the plastic viscosity (PV), yield point (YP), and gel strength make up mud's rheological properties. These properties follow the Bingham plastic rheological model for non-Newtonian fluids (see Figure 3). These properties are computed using a device called a viscometer and are reported usually twice daily on an API drilling mud report. In general an increase in solids content will increase plastic viscosity, thus decreasing ROP because of higher frictional losses in the drillstring make less hydraulic energy available at the bit.

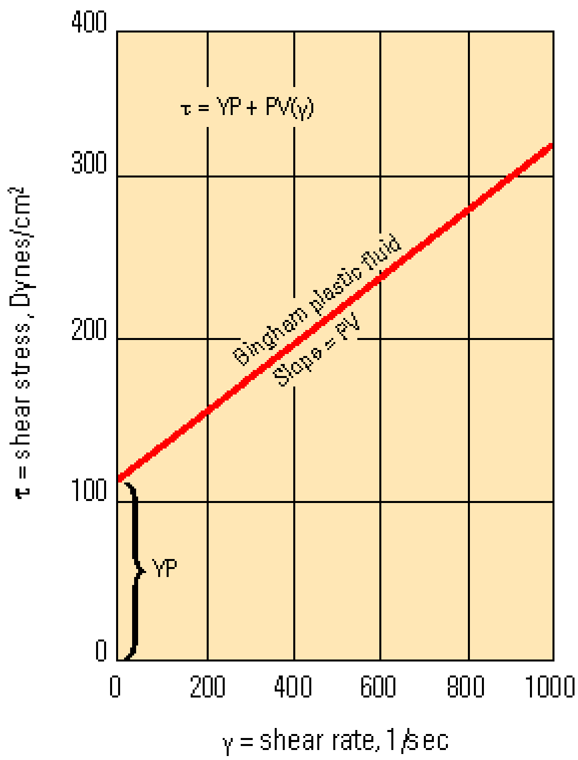

Figure 3: Bingham-plastic fluid model graphic

(http://www.glossary.oilfield.slb.com/DisplayImage.cfm?ID=374, October 2010)

Mud filtrate is the liquid component of drilling fluid, the other being the solid particles. This filtrate penetrates permeable rock adjacent to the wellbore thus leaving behind a "filter cake" which is critical to maintaining wellbore stability and avoiding loss circulation. The filtrate also enters the rock ahead of the bit while drilling equalizing differential pressure and increasing ROP. Studies have shown[4] that filtration rate has less of an effect when drilling through low permeable rocks and a greater effect on high permeable rocks. For WBM it was noticed that filtration only has an effect when it is too low, a leveling off effect was noticed with ROP with increasing filtrate rates. It can be concluded that ROP is aided by filtration, but only until an optimal level is reached. Beyond that level, higher filtrate values will not aid in the increase of penetration rate. This effect was more noticeable in high permeable formations where the filtrate can infiltrate the rock more easily and decrease differential pressure[4].

The solid part of drilling fluid is made of additives such as bentonite, and particles of rock that have been drilled. These solids affect the rheology of the mud and can affect ROP. Early research has shown that the increase of solids in mud will affect the mud's viscosity as it flows through the bit nozzles (Eckel, John pp541 1967). As the amount of solids and containments in the mud increase, the apparent viscosity and ECD of the mud also increase. This increase in viscosity leads to a decrease in penetration rate. A study was performed that examined the effect of rheology on ROP[5]. This study focused on analysis of field data for changes in fluid rheological properties while keeping all other drilling parameters the same to examine the direct effect these fluid properties had on ROP. The results of the study show that as the mud is circulated it picks up solids and other contaminants which affect the fluid's rheology. The contaminated or "recycled" mud performance was compared to new mud. The results show that the new mud had on average an increase in penetration rate by 58% over the recycled mud. Direct relationships were found between ROP and viscosity, equivalent bentonite content, flow behavior index, and Reynolds number at the bit. This led to the development of a fluid maintenance program to eliminate solids and keep the viscosity of the fluid low. Their cost analysis showed that the increase in drilling performance offset the cost of the fluid maintenance program. Conclusions from this study show the importance of rheological properties on penetration rate[5].

Mud chemistry becomes a factor in penetration rate because of chemical reactions between the mud and the drilled formation. Substantial work could not be found that gave definitive results of varying chemistry on penetration rate. Most work[6-7] focused on the chemical reactions between mud and rock which leads to differing results in ROP which is more pronounced in shale where bit balling is an issue. In general mud chemistry is dictated by needs of other factors such as wellbore stability, friction reduction, environmental concerns, and general mud properties.

Bit operating conditions include weight on bit (WOB) and rotary speed (RPM) that are applied when drilling. These properties are dependent on the drillstring design and the available power of the drilling rig. Drillstring design has a direct effect on WOB the size and number of drill collars in the BHA dictates WOB. Two parameters need to be monitored in drillstring design buckling strength and maximum tension. The stresses in the drill string need to remain in between these two parameters or serious damage can occur to the drillstring. Significant WOB can be applied but if it is too high the pipe will buckle. Buckled pipe should never be rotated. Increased WOB and RPM has been shown to increase ROP[1]. However at high WOB and RPM the ROP can decrease due to poor hole cleaning, likewise bit wear is also generally increased with increasing WOB and RPM which can lead to premature bit trips[1].

ROP tends to decrease the longer a single bit has been in operation, this is due to bit wear. Bits become dull and teeth/cutters are broken or worn off with prolonged drilling time especially in hard abrasive rock zones. Both the drilled formation characteristics, bit cleaning and cooling, and bit operating conditions have a direct impact on bit wear. As noted above certain bits are designed to operate under a set of conditions through particular formation characteristics. Some bits will experience wear at different rates, and all will eventually wear to the point where the bit must be replaced. Field evaluation of bit wear is difficult as the bit must be visually examined to confirm bit wear or other bit damage. Obvious indications of bit wear include a drop in ROP when there is no significant change in lithology or the failure of the bit to continue cutting (ROP=0). Terminating a bit run is a judgment call and is often made with some uncertainty about the best time to do so. Bit life can often be established after several wells have been drilled in the same field after the lithology of the area is established. See Figure 4 below for an example tricone bit with substantial wear.

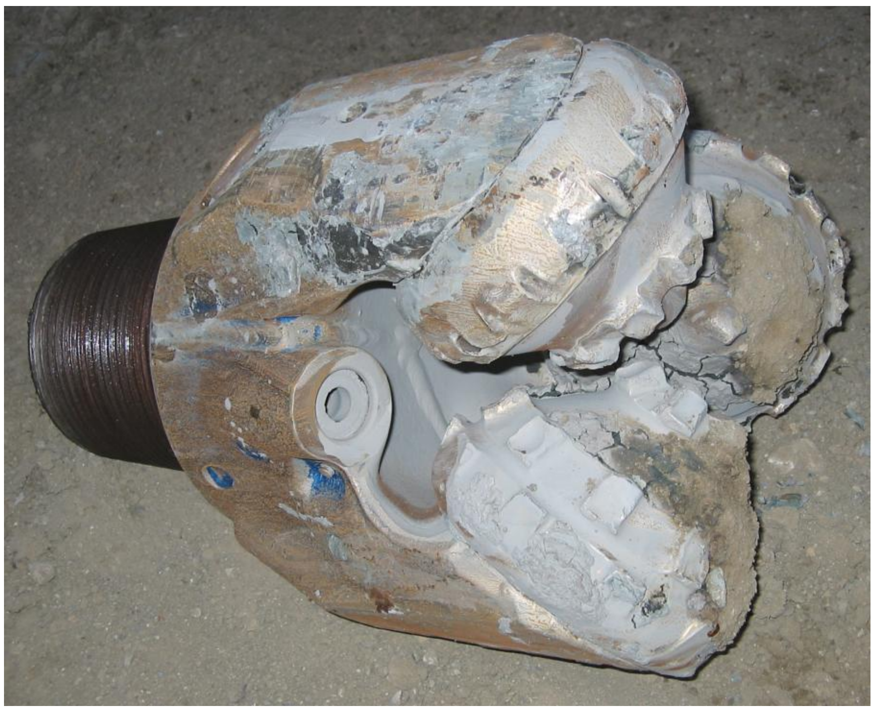

Figure 4: Shows Tooth Wear on a Tricone Bit

(http://www.enotes.com/topic/Well_drilling, October 2010)

Bit hydraulics play an important role in rate of penetration. For optimal ROP a steady-state of needs to be reached between the generation of cuttings and the removal of said cuttings from the hole. Efficient and effective bottom hole cleaning is a critical characteristic for enhancing ROP. Jet-type roller bits have been around since the 1950's and have improved bit performance from previous designs. These bits along with modern bits include multiple jets or nozzles in the bit that accelerate the mud velocity exiting the bit. This creates a "jetting" action which improves bit cleaning, cooling, and bottom hole cleaning. The common parameters used to describe bit hydraulics are hydraulic horsepower, jet impact force, and nozzle velocity. Hydraulic horsepower (HHP) is given by the following equation[1]:

$$HHP = \Delta P_b Q/1714$$

where ΔP_b is the pressure drop across the bit in psi, and Q is the mud flowrate in gallons/min. Jet impact force (F_j) is given by[1]:

$$F_j = 0.01823 C_d Q \mathrm{sqrt}(\rho \Delta P_b)$$

where C_d is a discharge coefficient, Q is flowrate in gal/min, ΔP_b is pressure drop across the bit, and ρ is density. All the hydraulics parameters are dependent on the pressure drop across the bit. This pressure drop represents the increase in velocity of the drilling fluid as it exits the nozzles. The maximum HHP, F_j, and nozzle velocity is reached when pump pressure is maximum, and frictional pressure drop in the drillstring and annulus is at a minimum[1]. It is uncertain which hydraulic parameter is best used for evaluating ROP, therefore all three are commonly used in analysis. Experimental data has shown that an increase in all of these parameters will result in an increase of ROP[1,8].

Bit balling is the “sticking” of rock particles in the crevices of a drill bit thus decreasing the bit’s performance. This phenomenon is common when drilling shale with a PDC bit. Shales can be clay rich which have a tendency to hydrate (draw in water) and swell. This causes the rock to swell, causing an increase in “swelling pressure” which can cause a shale cutting to vacuum “stick” itself to other cuttings and to the face of the drill bit (see Figure 5). This has a great effect on PDC bits because the cutters can become blocked by sticking shale and are rendered useless. These shale cuttings can also attach themselves to other BHA components including drill collars, MWD/LWD tools, motors, and so-forth. When a bit becomes balled its ability to cut rock is decreased thus the ROP is decreased, so for maximum ROP bit balling must be kept at a minimum or eliminated. Nozzle placement, bit face dimensions, and sufficient HHP are the recognized factors that minimize bit balling[8-9]. When drilling with WBM, bit balling is more common than when drilling with OBM. The use of ROP enhancers in WBM formulations has led to the elimination of bit balling[8-9]. These ROP enhancers work by “oil-wetting” the shale cuttings which prevents the sticking of the clay to the bit or BHA. ROP enhancers are a type of lubricant that is added to the mud; many different formulations of ROP enhancers exist and are commercially available.

Figure 5: An Example of Bit balling

(http://www.ogj.com/index/login.html?cb=http://www.ogj.com/ogj/en-us/index/article-display.articles.oil-gas-journal.volume-95.issue-16.in-this-issue.drilling.pao-lubricant-inhibits-bit-balling-speeds-drilling.html, October 2010)

Predicting Penetration Rate

All of these ROP controls have independent effects on ROP which have been established through conventional experiments. However, complexities arise when all of these controls are brought together in a real world drilling situation and overall the behavior is not well understood. Some service companies offer mathematical computer models that are aimed at optimizing a drilling program. These models are mathematically complex; therefore details will be not be mentioned. There are some simple mathematical models that have been created to predict penetration rate. For a drag bit the penetration rate can be estimated by[1]:

$$ROP = L_{pe} n_{be} N$$

and:

$$L_{pe} = 0.67 L_p$$

$$n_{be} = 1.92(C_c/s_d) d_b \mathrm{sqrt}(d_c L_p - L_p^2)$$

where

- L_{pe} is the effective penetration of each cutting element
- n_{be} is the effective number of blades
- N is rotary speed (RPM)
- L_p is the actual depth of penetration of each stone (in)
- C_c is the concentration of diamond cutters (carats/in^2)
- d_b is bit diameter (in)
- d_c is the average diameter of the face stone cutters (in)
- s_d is diamond size (carats/stone)

This model was developed considering the following assumptions:

1. The bit has a flat face that is perpendicular to the vertical axis of the hole.
2. Each blade is formed by diamonds laid out as a helix.
3. The stones are spherical in shape.

4. The diamonds are spaced so that the cross-sectional area removed per stone is a maximum for the design depth of penetration.
5. The bit is operated at the design depth of penetration.
6. The bit hydraulics are sufficient for perfect bottom hole cleaning.

This model was presented by J.L. Peterson in “Diamond Drilling Model Verified in Field and Laboratory Tests” in February of 1976 and is only good for drag bits under the stated assumptions. Therefore, its applicability today is limited. Examination of an analogous well of all the ROP factors and the actual ROP is a more popular trend in today’s world.

ROP vs. Drilling Efficiency Discussion

This thesis primarily focuses on a way of increasing ROP. However the discussion of ROP vs. drilling efficiency should be noted. The industry’s common viewpoint is there is a direct relationship exists between ROP and drilling efficiency i.e. when ROP increases drilling efficiency increases and vice versa. Studies have been performed that invalidate this viewpoint and prove that ROP must be viewed as one of several factors in determining drilling efficiency[10]. ROP is physically the speed at which the drillstring is moving while drilling measured by travel of the top drive or Kelly-drive. The objective of drilling efficiency is the reduction of the cost per foot of each drilled section summing up to a successful well. As discussed earlier there are many factors affecting ROP, likewise drilling efficiency is controlled by several factors. They include invisible lost time, unplanned events, and performance qualifiers[10]. Essentially an increase in ROP does NOT guarantee an increase in drilling efficiency. An example might be that increasing the WOB will increase the ROP but will decrease the life of a bit leading to an unplanned bit trip which is an example of lost time. Depending on the current depth, the trip can take more time to trip out/in with a new bit than it would to run a single bit through the same interval at a lower WOB. The increase in WOB can also lead to hole deviation issues which can lead to additional problems with the well (unplanned events). Another example would be decreasing the mud weight which has been shown to have a positive effect on ROP. A decreased mud weight will result in lower BHP which can lead to well control or wellbore stability problems. Well control issues can result in lost time when killing the well and circulating the kick out or the loss of the well in the extreme case of a blowout. Wellbore stability problems are the primary cause of un-planned costs and non-productive time when drilling a well[6]. Stability issues may lead to back reaming, premature setting of casing, stuck pipe, and the potential loss of the well. The drilling program must be evaluated as a whole with the common goal of decreasing the cost of the well not the instantaneous increase of ROP[10].

HTHP Drilling

HTHP is defined as high-temperature high-pressure and is a challenging environment to successfully drill a well. Thresholds for HTHP vary by source but generally above 10,000 psi and 300°F are considered HTHP and above 20,000psi and 500°F are considered ultra-HTHP. Regardless, HTHP drilling technology and research is an important topic in the present day exploration & production business.

As the industry pursues oil & gas deposits that are in deeper and are in harder to reach locations challenges, arise during the drilling of these wells. The deeper the wellbore the higher the temperature and pressure due to the proximity of the earth's core and the increase of overburden pressure that compacts pore fluids. Thermal and pressure gradients vary by location but are generally between 13-15^{o}F/1000ft, and 500-800psi/1000ft respectively. Therefore at greater depths the temperature and pressure is increasing so the term ultra-deep is synonymous with HTHP. Some operators have drilled wells in Texas, Louisiana, and Wyoming that are up to 25,000ft in depth and have experienced a variety of problems and challenges but have provided unique solutions in each case[11-12]. Some common challenges with drilling HTHP/ultra-deep wells are:[11]

- Costs are high
- Mechanical limit of drilling equipment (drillstring, MWD/LWD, motors, etc.) can be exceeded
- Temperature effects to mud, cement, and drilling equipment
- Increased stresses & hard rock in deep formations
- Low penetration rate
- High frictional pressure losses in drillstring/annulus
- Well control issues

- Higher consequences for human error

All of these challenges present a higher level of risk as opposed to lower pressure/temperature wells. Reduction of this risk is an important factor during the design, planning, and execution of an HTHP well. These wells require more data acquisition and analysis from analogous wells. From this data the design engineer can hopefully reduce some of the uncertainty in the temperature & pressure profiles, formation lithology, and other factors that can affect drilling operations. Careful examination of the mechanics of the drilling equipment (pressures, loads, temperature tolerance, etc.) must also take place to avoid mechanical failure. Mud programs are very important in HTHP wells as well control, stability, and performance characteristics are often significantly affected by mud properties. A good drilling program can be developed if all these factors are given careful consideration; however un-expected problems can always still arise during drilling requiring quick solutions[11-12].

Work is being done to improve technologies and provide better understanding/techniques for drilling these types of wells. This thesis focuses on solving one of the challenges (low ROP); while utilizing water based mud which can reduce another challenge (high costs). These technical challenges will always exist with these wells but as technology/techniques catch up the rewards of these wells can be achieved. Sufficient data gathering & analysis paired with through planning in the design phase and excellent drilling practices can lead to a successfully drilled HTHP/ultra-deep oil & gas well[11-12].

Mud Types

There are several types of drilling fluids (muds) that can be used; they include liquids (oil, water, synthetic), gas-liquid mixtures (foam, aerated water), and gases (air, natural gas). This thesis focuses on the use of liquid drilling fluids. Drilling fluids are utilized to perform the following functions:[1]

- Hole cleaning
- Well control
- Wellbore stability
- Bit cooling and lubrication

The selection of a drilling fluid is based on the following factors:

- Formation characteristics
- Temperature range
- Pore pressures
- Availability of water
- Environmental concerns
- Economics
- Performance

The optimal drilling fluid is based on the needs of the particular well to be drilled, therefore data gathering & analysis from analogous wells is an important stage of the development of a fluid program. Once a fluid program is designed and implemented, fluid maintenance while drilling is the next priority. In most cases a mud engineer, a drilling fluid expert, is continuously on site monitoring and manipulating fluid properties as needed thought the drilling phase. Fluid maintenance is an important job as discussed earlier containments and rock cuttings can have negative effects on the fluid properties which have shown to lower drilling performance[5].

Water based drilling fluids are the most common drilling fluid. This is largely because of the availability of water and the relative low cost versus other fluid types such as oil based muds. Water based muds are generally more than three-quarters water the other one-quarter is a composition of lubricants and varying density solids that impact the density and viscosity of the fluid. The most common solid additive is a clay called bentonite, which is chemically composed of sodium montmorillonite. The purpose of bentonite addition is density/viscosity manipulation and the creation of filter (mud) cake. As the drilling fluid comes in contact with rock formations in an overbalanced situation the fluid will invade the rock. This leaves behind solid particles such as bentonite, polymers, or LCM (loss circulation material) to clog pore throats and fractures creating the "mud cake". This mud cake is vital for avoiding loss circulation and maintaining wellbore stability. Other solids are introduced to the mud during the drilling process they include: sands, clays, limestone, feldspar, barite, and silts. For the most part these solids are un-desirable (except barite) because they affect rheology, density, and frictional losses so need to be removed from the mud. Processes for removal of these solids are screening, forced settling, chemical flocculation, and dilution. Chemicals are also added to WBM for pH control, viscosity control, filtrate control, and contaminant removal. Caustic, lignites, lignosulfates, phosphates, lime, gypsum, sodium bicarbonate, and sulfur are common chemicals added to water based muds[1]. Further discussion of water based muds will be presented later in the thesis.

Oil based muds are made from a liquid hydrocarbon; generally diesel fuel is selected because of its viscosity characteristics, low flammability, and low decomposition to rubber. Generally an oil based mud will be over half diesel fuel, about one-third water, and the rest solids. Oil based mud is selected for the following applications[1]:

- HTHP drilling
- Drilling salts, anhydrite, carnallite, potash, or reactive shales
- Formations containing CO_2 or H_2S
- Corrosion control
- Reduction in torque/drag in directional wells
- Drilling weak formations with low pore pressures

Additives are also utilized in oil muds to emulsify water, control wettability, viscosity, filtration, density, alkalinity, and solids contents. As stated oil muds have oil and water phases; the oil phase is generally diesel #2 fuel and the water phase is emulsified water.

The water must be emulsified to prevent water droplets from forming and dropping out of the solution. A calcium or magnesium fatty acid soap is generally added to oil mud to emulsify the water. They work by attaching themselves to the oil/water interfaces with the oil soluble end of the chemical chain in the oil phase and the water soluble end in the water phase. This will prevent each accumulation of water from connecting to another and separating itself from the mixture. Another additive to oil based mud is a wettability control additive. Naturally when two liquids are brought into contact with a solid one liquid will "stick" to the solid; this is referred to as the wetting phase. For oil based muds it is preferred that the wetting phase be the oil not the water. If the water acts as the wetting phase, drilled solids will be absorbed by the water and will eventually deplete the water phase causing high viscosities and the settling of barite. Generally the emulsified water is used to control viscosity in oil muds, but asphaltanies and amine-treated bentonite can be added to further increase viscosity. Lime is used to control alkalinity which can be used for corrosion control and the dissolving of harmful CO_2 or H_2S gasses. Barite is the main density control additive of oil based mud as with water based muds[1].

Another form of oil based mud is a synthetic based mud. The oil phase generally made of diesel in conventional oil muds is replaced with a lower toxicity fluid such as mineral oil or some kind of olefin. In environmentally sensitive areas the use of OBM presents high environmental risk and in some areas is not allowed. Examples of these types of areas are offshore, near wildlife sanctuaries, and areas near highly sensitive groundwater. For instance, in the Gulf of Mexico and North Sea regulations are in place that restrict the disposal of cuttings into the ocean that have been drilled with OBM[13]. Therefore the development of a mud that maintains the same performance properties as oil based mud but is environmentally friendly is highly desirable. These muds are often very expensive, have proven their reliability, and have shown to be cost effective when the overall economics are considered.

Drilling fluid type is dependent on the needs of the well and the conditions for which it is expected to perform under. Each mud type has its own set of advantages and disadvantages. Table 1 below lists each liquid mud type and some example advantages and disadvantages[14-18].

Table 1: Advantages/Disadvantages of different mud types

Type	Advantages	Disadvantages
Oil Based	Good rheological properties at high temperatures	Expensive
	Will not react with shales	Not environmentally friendly
	Effective against corrosion	Can affect performance of logging tools
	Excellent lubrication properties	Treatment for loss circulation more difficult
	Mud densities as low as 7.5 ppg	Detection of gas kicks more difficult because of solubility
	Resistance to contamination	Can negatively affect completion operations
	lower torque & drag	
Water	Low cost	Poor performance relative to OBM
	Available	Shale stability issues
	Considered environmentally friendly	Poor tolerance to high temperatures
Synthetic	Performance similar to OBM	Very Expensive
	Considered environmentally friendly	

Focus on Water Based Mud

As mentioned before water based mud is the most popular drilling fluid utilized today, however it does come with a unique set of advantages/disadvantages. Some advantages such as the low cost, availability, and low environmental impact have driven the experimentation and research of the use of WBM in applications that previously were reserved for oil based muds. HTHP, directional wells, and ultra-deep offshore are a few of these scenarios. Recent research has been performed[13,17] with the objective of finding a water based system that exhibits oil based performance but does not exhibit oil based costs or environmental concerns. Dye et. al.[13] presented on a high performance water based mud (HPWBM) system that was developed to achieve the following goals:

- Shale stability
- Clay inhibition
- Cuttings Stability
- Good ROP
- Low bit balling
- Reduction in torque & drag

In order to have shale stability, one must eliminate the invasion of filtrate into the rock. This filtrate invasion causes pore pressure to increase in the near wellbore region which is already at high stress from drilling to become unstable. In order to eliminate this, a barrier must be created between the mud and the wellbore walls. The HPWBM utilizes both physical and chemical techniques to address this challenge. First, a micronized deformable sealing polymer is used to physically block off pore throats and micro-fractures. This provides an impermeable barrier that "plugs" up the passageways that the fluid can travel through. A second technique utilizes aluminate chemistry that is soluble in the mud but precipitates when it enters a shale matrix due to a reduction in pH and a reaction with multivalent cations. This precipitate acts as an internal barrier that paired with the polymer provides excellent membrane efficiencies. In addition to this barrier an osmotic pressure differential is created using a salt to increase salinity. This pressure differential will drive water out of the rock and into the fluid thus de-hydrating the shale. When dehydrated pore pressure decreases, clay swelling decreases and a more stable condition is created[13].

Clay inhibition is the suppression and dispersion of clays and gumbo. If the clay is allowed to hydrate and swell problems such as bit balling, poor hole cleaning, and mud contamination can occur. Wellbore instability problems in shales can also exist if swelling clays increase the stresses in the shale. Therefore clay inhibition is an important attribute of a good drilling fluid. The addition of potassium chloride is a common solution for the clay inhibition problem. However KCl does come with some disadvantages such as its inability to suppress clay swelling in certain clays, does not provide the best osmotic pressure differential compared to sodium chloride, and KCl is banned in certain areas such as the Gulf of Mexico. Therefore KCl is not utilized for clay inhibition in the HPWBM. Alternatively an environmentally acceptable, water soluble clay hydration system (CHS) is utilized. The chemical formulation is not given, but the CHS is said to function similar to the KCl but is not limited in its use by environmental concerns. Tests confirm the effectiveness in reduction of hydration and swelling with the CHS versus a base fluid[13].

The above techniques for shale stability and clay inhibition also apply to cuttings stability. A third technique that the HPWBM integrates is the addition of a polymer that acts to encapsulate cuttings as they are circulated through the annulus thus preventing disintegration. This stabilization of cuttings will lead to better hole cleaning and better solids control thus keeping mud contamination down and avoiding potential drilling performance limitations[13].

Oil based muds outperform water based systems in ROP, anti-balling, and friction reduction. The HPWBM addresses these shortcomings through the previously mentioned CHS and an anti-balling additive. The CHS as mentioned suppresses clay swelling which will decrease the tendency of the clay to stick to the bit and BHA components, thus reducing bit balling and increasing ROP. The HPWBM also contains a patented anti-balling additive that coats the metal and rock with base fluids and surfactants. The additive is ideally injected continuously during drilling to provide a non-emulsified supply of the material to the bit. The additive coats the metal surfaces of the bit which eliminates the adherence of cuttings thus reducing balling. The additive also reduces the accumulation of cuttings to each other which leads to improved bottom hole cleaning. The same additive acts as a friction reducing agent between the drillstring components and the open hole/casing. A reduction in friction will lead to a reduction in torque and drag in the drillstring which is a common limiting factor in horizontal/extended reach wells. Test results of the HPWBM show that with increasing additive concentration a reduction in friction factor is observed[13].

This research shows that manipulation of a water based fluid can solve some of the downfalls that are usually associated with water based muds. A similar paper[8] presents on the successful drilling of a well in the North Sea that is typically drilled with a synthetic based fluid. The same factors as listed above were addressed with a different but effective formulation of water based mud. Extensive modeling and planning was done for this particular well which led to a reduction in risk and an increase in the chances of success. Intervals were identified where the mud needed to be modified for better performance from a shale inhibition standpoint using a dielectric constant measurement technique. Conclusions from this example show that through extensive planning mud treatment that a water based fluid can be successful in this type of environment[17].

With growing environmental concerns and very dynamic commodity prices the need for a low cost, high performance and environmentally friendly drilling fluid is acknowledged. The use of water based drilling fluids in circumstances when oil based is generally reserved will be the focus of research in petroleum engineering in the future.

Wellbore Stability and WBM

Wellbore stability is defined as the maintenance of constant wellbore size, shape, and direction. Rocks at depths are subject to in-situ stresses that are caused by the weight of the rock above them. Over time these rocks have reached a state of thermal, physical, and chemical equilibrium. Drilling removes a volume of rock, replaces it with drilling fluid, thus altering this state of equilibrium. Stresses are re-distributed and a stress-concentration is formed in the rock in the near-wellbore region. Heat is transferred to/from the rock and drilling fluid. And chemical reactions can take place between the rock, formation fluid, and drilling fluid. The maintaining of a stable wellbore is critical to the drilling process. Problems such as hole enlargement, fracturing, hole reduction, and collapse can cause serious and costly problems during the drilling process. A good understanding of the causes of these issues and data analysis from analogous wells is critical for the design of a good drilling program[1].

Shale can account for over three-quarters of the drilled formation in most oil & gas wells and most wellbore stability issues are related to shale. Therefore, shale stability problems have the potential to be the leading cause of un-anticipated costs during drilling. Characteristics of shale such as its susceptibility to fresh water, rock strength, low permeability, and susceptibility to thermal effects are the primary causes of shale instability[15].

As discussed earlier shale contains clay, which tends to swell when introduced to fresh water. Mud additives and bit hydraulics can solve the bit balling problem associated with swelling clays. However wellbore stability problems can also be complicated with swelling clays. The rock in the near wellbore area is under higher stresses due to drilling activity, swelling clay will increase this stress. If the stress exceeds rock strength then failure will occur. Oil based mud is an easy solution to the clay swelling problem, but clay inhibition can be achieved with water based mud. One way to accomplish this is to decrease the water activity of the drilling mud. The addition of electrolytes such as NaCl, KCl, lime, gypsum, xanthan, and some polymers can chemically create an osmotic pressure differential between the rock and mud that will drive water out of the clay and into the mud. This de-hydrates the rock, thus eliminating clay swelling and sticking which will reduce bit balling and promote a more stable wellbore condition.

Most shales experience very low permeability's (nano-pico Darcy range) this low permeability can cause complications with wellbore stability. As discussed earlier when mud is in contact with rock the mud filtrate invades the rock leaving behind a filter cake. This invasion of filtrate into the rock also increases the pore pressure of the rock that is invaded. An increase in pore pressure leads to a decrease in confining pressure which, when expressed by Mohr circles will shift the circle to the left. If the shift is large enough the Mohr circle can intersect the established failure envelope. With shale permeability very low this confines the filtrate to the near wellbore wall vicinity only as it cannot penetrate any further. The stresses are already at their highest around the wellbore wall. In order to reduce filtrate invasion an impermeable membrane must be created by plugging pore throats and fractures. Several different polymer mud additives exist that physically block flow to the pores and fractures. They work by bonding together and getting stuck in these openings. Another technique is to use a chemical additive that will precipitate when in contact with the rock, the precipitate will fill the voids and block off flow into the rock.

Heating of drilling fluids will cause them to expand, if filtrate or formation fluid is already present in a particular rock and heat is transferred to it, it too will expand. This expansion will cause the pore pressure in the rock to further increase thus enhancing the effects. Thermal effects can become a problem in wells with large sections of open hole and high bottom hole temperatures. The mud will be heated downhole then travel up the annulus, transfer heat to the shallower formations, and increasing the risk of instability problems.

In order to successfully drill shale with water based mud ample data gathering, analysis, planning, and monitoring of wellbore conditions and mud properties must take place. Without good knowledge of what is taking place downhole, problems are likely to arise.

Future Work/Research Regarding ROP

As stated before the controls on ROP are dependent on a variety of controllable and un-controllable factors. Optimal bit selection, operating conditions, mud type, and properties can be selected after a significant number of offset wells have been drilled in an area. Uncertainties will always exist so planning a good drilling/mud program is not an exact science. Since ROP dictates total drilling time, cost benefits will always exist when a reduction in drilling time occurs. Therefore research of the future is expected to focus on maximizing penetration rate by manipulation of the stated ROP controls.

CHAPTER II

RESULTS

Introduction

As mentioned before the purpose of this project is to investigate the performance properties of different drilling fluids in conjunction with PDC drill bits in deep HTHP environments. Early indications lead to a hypothesis that drilling performance is superior when water based fluids are utilized versus oil. Figure 6 in the appendix shows bit runs from wells in the Deep Bossier Sands field. Bit type, depth in/out, penetration rate, and fluid type are identified on this chart. The square data points indicate bit runs with water base, and the circle data points indicate oil base. From examination of this chart it is clear that many of the water based bit runs experience better performance than the oil base along with extended life. Refer to the bottom right quadrant of the graph which represents the deeper well section and the faster penetration rates. This chart was an early indicator that supports the hypothesis. This hypothesis is counter intuitive to the conventional industry procedure when dealing with HTHP wells which is to use oil based mud. Oil based mud is utilized in this situation because of its ability to withstand high temperatures, contaminant tolerance, low drag properties, and non reactivity to shale. Oil based fluids, nevertheless, have one major disadvantage; which is cost. High volumes of oil base fluids are very expensive as they are diesel based as opposed to water, storage, and disposal in an environmentally friendly & regulatory compliant manner is also expensive. For these reasons water based fluids are used when feasible. This thesis will present data from fourteen gas wells drilled into the Deep Bossier Sands in Leon County, Texas. The data indicates that in the deeper intervals (>14,500ft) that penetration rates are higher with water based mud than oil base. With penetration rates around ten feet per hour it often takes a month or more and several drill bits to drill these deeper intervals. Therefore, significant costs are incurred during this period of time. These costs can be reduced by increasing the penetration rate and decreasing the drilling fluids cost. The evidence presented in this thesis will show that these cost savings can be obtained by drilling with water based mud and PDC bits in these types of environments. Background of the area and wells used for analysis will be presented along with the data gathering & analysis methodology. The data validating this performance trend, possible root causes, conclusions, and a recommendation on a path forward will also be discussed in this thesis.

Background on Deep Bossier

The Bossier Sands oilfield is located in East Texas in Robertson and Leon counties. It is considered an unconventional play that has been explored by multiple US operators since 1980 and developed since 2003. Sediment deposition occurred in the Jurassic period in the deep marine environment. Multiple production zones exist in the Bossier formation as deep as 20,000ft. Wells in this area experience high initial production, long life, and high recovery percentages. These wells are often vertical or S-shape stimulated by hydraulic fracturing. These wells represent a significant drilling challenge due to the temperatures and pressures that are observed at depths beyond 15,000ft.

Origins of Data

After the data presented in Figure 6, was analyzed it was clear that a group of wells from close proximity needed to be identified and data collected for more thorough analysis. Data from fourteen wells was obtained and analyzed. These wells all come from the "Hilltop Lakes" area of Leon County, Texas and are drilled into the Deep Bossier Sands. Seven of the wells were drilled completely with water based mud. The other seven wells were drilled with oil based mud in the deeper intervals. Bit records, mud logs, morning reports, and EDR data was source of data for these wells. Each well was examined and analyzed for comparability with the others. A summary of the wells is shown below in Table 2.

Table 2: Data Summary of All Wells

Well	Mud Type	TVD	Avg. ROP	Avg. H S I	Avg. PV	Avg. YP	Corrected Downhole PV
1	**WBM**	**18,022**	12.95333	2.9	30.13333	9.87	30.133
2	**WBM**	**18,525**	12.12381	3.2	23.66667	8.33	23.667
3	**WBM**	**18,791**	10.74828	4.2	25.86207	6.2	25.862
4	**WBM**	**17,266**	11.55	3.68	23.77778	6.09	23.778
5	**WBM**	**18,000**	10.24706	1.835	29.94118	7.88	29.941
6	**WBM**	**18,250**	14	4.88	23.94118	8.18	23.941
7	**WBM**	**17,800**	8.61	1.77	33.01968	10.5	33.020
8	**OBM**	**19,000**	6.243133	0.1	36.34072	8.49	7.268
9	**OBM**	**18,200**	7.509079	0.98	36.44412	8.62	7.289
10	**OBM**	**18,800**	6.354455	0.24	56.43589	10.97	11.287
11	**OBM**	**18,090**	5.747727	0.75	54.14286	10.05	10.829
12	**OBM**	**19,106**	5.1375	0.4734	46.3125	8.25	9.263
13	**OBM**	**19,500**	5.712778	0.679	39.68571	9.05	7.937
14	**OBM**	**18,900**	5.214286	1.14	52.37037	8.59	10.474

Data Analysis Methodology

As mentioned before the sources of data originated from several different sources. The best data was obtained from EDR data as it shows all recordings of all drilling variables on a foot-by-foot basis. As this data is recorded instantaneously on a recorder there is often a significant amount of "noise" associated with the data. In order to smooth out this data, an average was taken over several footage intervals. These footage intervals are between 150-200ft, and only data from beyond 14,500ft was examined. The other sources such as morning reports, bit records, and fluids reports are given on a day-by-day basis. Therefore the average penetration rate, fluid properties, and depths are already established. In general a drilling rig would make about 100-200ft of progress per day at these depths. With this formatting, all the data from each source was matched up and considered congruent. Microsoft Excel was utilized for all the data analysis. Once the data was compiled, penetration rate versus several characteristics was plotted and trended. These plots are used to examine the behavior or influence that a particular characteristic has on penetration rate. Figures 7-19 in the appendix shows these plots.

Data Presentation

Please refer to Figure 7 in the appendix for the following discussion. Figure 7 shows all fourteen wells average penetration rate through 100-200ft intervals versus depth. The blue circles represent wells 1-7 which were drilled with water based mud. The red triangles represent wells 8-14 which were drilled with oil based mud. The blue and red horizontal lines represent the overall average of the water base and oil base wells respectively. The water base wells had an average of **11.28ft/hr** penetration rate and the oil base wells had an average of **5.98ft/hr**. That represents an **88%** increase in penetration rate with the water base over the oil base. Running simple economics it would take 354 drilling hours to drill 4,000ft with water base mud, and 680 hours with oil based mud. Assuming a rig day rate of $20,400/day or $850/hr the water base fluid could save an operator **$267,100** drilling this 4,000ft alone. That's just drilling time, other cost savings would originate from reducing fuel consumption, reducing operator's personnel time, and fluids savings by using water based mud. Elimination of standby time for third party contractors is another source of savings. If an operator budgets about $50,000 per day for a similar well then the savings is over $600,000 per well.

Limitations of PDC Bits

It was observed that during the drilling process in the oil based wells, the operator noticed that beyond 18,000ft the drillibility of PDC bits was reduced to the point that these bits were no longer economically viable. These bits were only lasting a short time before their penetration rates reduced drastically and a bit trip was necessary. With bit trips lasting a day or more the operator opted to use diamond impreg bits at these depths as a means to reduce the overall cost of the well. The reasons behind this lack in performance are not yet known, and no research has been done in this area. Therefore, in Figure 8 the oil base data was split up into red and green (triangles) data points. The red were drilled with oil based mud and PDC bits, and the green were drilled with water based mud and diamond impreg bits. The average penetration rate of the oil base wells with PDC bits is **6.955**ft/hr and **5.478**ft/hr for the impreg bits. It is expected that the impreg bits would drill slower because of their less aggressive cutting structure and the reduction in bit hydraulics. However, the oil base with PDC bits still experience significantly lower penetration rates across the data set. Therefore, the main comparison will be between the differences between the two mud types and how they affect penetration rate in this environment. Future research is needed in this area to determine the limits of PDC bits. It should also be noted that none of the water based wells were drilled deeper than 18,500ft. The operator did not provide reasoning for this, but it is possible that a similar decline in performance was observed in these wells too. This leaves question one unanswered, experimental work needs to be performed on this topic to provide answers.

ROP Controls

This information supports the theory that water based mud is out performing oil based mud in this environment. Clearly a fundamental difference exists between the two mud types that is influencing this trend. In order to analyze this, the original penetration controls must be revisited. Recall that the following accepted controls on ROP are[1]:

- Bit type

- Formation characteristics
- Drilling fluid (mud) properties
- Operating conditions
- Bit wear
- Bit hydraulics

Since all the sample wells are from a close vicinity to each other and the depth interval selected for analysis is also the same then the formations are virtually identical. Therefore, formation characteristics are not a possible driving force behind this performance trend.

The operating conditions for any bit are usually specified by the bit manufacturer for optimal performance. They will specify a range of weight on bit (WOB) and rotary speed (RPM) for which the bit is designed to be subject to. For the sample wells, the assumption is made that both operators kept these bits under their recommended operating conditions throughout each of the wells. Therefore, bit operating conditions can be excluded from the driving factor in this performance trend.

Bit wear is characterized by the oil base mud's effect on the PDC bits. This trend is not well understood at this time, and the data supports the notion that water base mud can still drill these deep formations effectively (see Figure 8). More research needs to be performed to explain this phenomenon. There exists some property in the water base mud that reduces the bit wear and allows for effective drilling. This factor is a partial contributor to the overall observed performance trend.

For the sample wells in question, two types of bits were utilized; PDC and Impreg (refer to Figure 8). The Impreg bits were used exclusively with the oil based muds because of a drop in performance with the PDC bits. Therefore, an exact comparison holding bit type constant while varying fluid type/properties cannot be concluded from this data. Therefore, the study on why the water based mud allows for drilling with PDC bits in these deep intervals will have to be done as the cause of this is still unknown. Looking at the PDC bits exclusively the water base wells had an average penetration rate of 11.28ft/hr while the oil base had 6.96ft/hr. So there is still an improvement in penetration rate when water based mud is utilized over oil base with either bit type. Figure 9 in the appendix shows the three most popular PDC bit types for the water base wells utilized in the deep intervals. They are the Smith MSI613WPX, Hycalog DSR711DB, and the Security FMHX543ZZ. Their average penetration rates are 10.159, 10.183, and 10.411 respectively. These penetration rates are very close to each other, therefore it can be concluded that the penetration rate in this case is not dependent on bit type.

Now that formation characteristics, bit operating conditions, bit wear, and bit type have been examined drilling fluid properties, hydraulics, and the fluid properties' effect on hydraulics must be looked at as possible causes of the observed performance trend.

As mentioned before HSI or horsepower per square inch is a normalized bit hydraulics characteristic adapted for any hole size. It is dependent on fluid flow and bit nozzle size. The role of bit hydraulics is to help keep the bit clear of cuttings and reduce bit balling. High bit hydraulics lead to better hole cleaning and better bit performance. Therefore HSI is an attribute to investigate in these wells. Figure 10 in the appendix shows penetration rate versus HSI as noted from the daily fluids reports for all fourteen wells by bit run. The impreg bits experience very low HSI due to the loss in fluid energy from the turbines. For the PDC the data supports the generally accepted[1] trend that higher bit hydraulics corresponds to better penetration rates. In this Figure the water base is shown to again outperform the oil base wells even though the HSI values experience overlap. This shows that water based muds do not increase HSI over oil base because of fluid properties alone but still experience better penetration rates.

Plastic Viscosity is the slope of the shear stress/shear rate line above the yield point. Basically it is a characteristic of how "thick" the fluid is and how much energy is needed to deform it. Higher viscosity leads to lower penetration rates due to a reduction in hydraulics through an increase in fluid pressure loss due to friction. The mud engineer draws samples from the mud tanks at the surface to use for the mud check. This mud is between 90-120°F, the downhole mud temperature is much higher. Since some of the mud properties (PV in particular) are sensitive to temperature and pressure changes, these properties must be adjusted to reflect the downhole environment. The wells used for analysis are at roughly 350°F and over 15,000psi, therefore the circulating mud is expected to be between 250-300°F when it reaches the bit. Plastic viscosity in oil and water based muds is temperature dependent. Previous work has been done to coorelate mud properties between different temperature and pressure regimes (13458) for both oil and water based muds. Politte (13458) provided a correlation for 80/20 oil/water emulsion at 15,000psi; the result is a $PV_{downhole}/PV_{@\ 90°F}$ of 0.20 (Figure 13 in appendix of 13458). Taking this ratio an estimation of the downhole plastic viscosity can be made; refer to Table 2. Water base mud does not behave as predictably as oil base with regard to temperature and pressure changes. There is no good resource that presents a correlation of rheological properties to similar water base muds used in these wells at higher temperatures and pressures. Therefore, no correction can be made for the water base fluids. Figure 11 in the appendix shows the penetration rate as a function of plastic viscosity. Notice that both the water and oil base fluids follow the common trend of increasing PV, decreasing ROP. The PV values of the OBM are reduced by 80% as provided by (13458). No conclusions can really be drawn from this chart other than the fact that both fluids behave as predicted. This leaves the cause of the performance behavior of the water base fluids to still be unknown.

Water base fluids are generally composed of mostly water along with solid and liquid additives that control density, rheology, and chemical composition. Oil base fluids are primarily diesel base with 20-30% emulsified water and liquid/solid additives. The water phase in oil base fluids is held together by soap molecules that prevent the water from falling out of the solution. The result is filtrate "bubbles" of water that are small, but large when compared to shale or tight sandstone pore throats or micro fractures. Their size is large enough to prevent them from entering these types of formations. Water base on the other hand does not contain these water "bubbles" which allows the filtrate to invade these smaller pathways. The effect of filtration rate on penetration rate has been established by previous research[1]. It is considered that the higher the filtrate rate the higher the penetration rate will be. The logic is that the filtrate can invade the rock ahead of the bit, decrease the differential pressure (difference between wellbore and formation pressure) and promote the removal of rock cuttings. This is characterized by chip hold down, where rock cuttings are stuck or forced to the wellbore floor/wall by the hydrostatic pressure in the wellbore. This leads to poor hole cleaning and a decrease in penetration rate. Water base fluid's filtrate characteristics allow this trend to be applicable in lower permeability formations. Therefore, this is a strong possible driving factor explaining the previously mentioned behavior. Figure 12 in the appendix shows the penetration rates versus the API filtrates for all the water base fluid wells. Looking at this chart, a generalized trend of increasing ROP versus increasing API filtrate does not exist. However if each well is isolated, wells 1-2 show downward trends, wells 3-4 have strong upward trends, and wells 5-7 have relatively flat trend lines. Refer to

Figures 13-19 in the appendix for these charts. Wells 3-4 show a strong correlation, but the lack of consistency between the seven wells does not prove that higher filtrate values can serve as the controlling factor in this performance trend. And since there is no way to correlate between API and HTHP filtrate values to each other, a legitimate comparison between the water and oil muds cannot be done. Therefore filtration characteristics cannot be proven to be the main influencing factor, but may be a contributing factor. Future research and some experimental work would have to be done to confirm or deny this theory.

CHAPTER III

CONCLUSION

The purpose of this project was to investigate the details of an observed drilling performance trend in an HTHP/hard rock environment. That performance trend indicated that water based drilling fluids were responsible for higher penetration rates than oil base fluids. Data from fourteen analogous wells was collected and analyzed for this trend. The results show that water base mud with PDC bits can experience an 88% increase in penetration rate over oil base. This results in significant time saved when drilling a similar well, which can lead to substantial cost savings. Also shown was the water base fluid's ability to allow a PDC bit to perform in an environment where oil base could not. The PDC bits with oil base mud were drilling at extremely slow penetration rates and not lasting as designed. Therefore the operator had to switch to diamond impreg bits from a cost standpoint. There are still many uncertainties about why this is happening. There is a fundamental difference between the interaction of drilling fluids and rock in this environment. There exists a property of the water base fluid that facilitates rock failure more efficiently than oil base. Most of the accepted controls on penetration rate are still followed, but there leaves no explanation on why the water base fluids are performing better. Bit hydraulics, filtration properties, rheology are all possible causes but a definite confirmation cannot be obtained from this particular set of field data. In order to investigate this problem further and come up with a solution experimental methods or additional data collection and analysis is necessary.

CHAPTER IV

FUTURE RESEARCH

As presented in this project there is clearly a difference between the behaviors of oil and water based drilling fluids in the HTHP/hard rock environment. The water base fluids in conjunction with PDC bits have been shown to outperform PDC or impreg bits with oil base mud in this environment. None of the general accepted ROP controls can provide a definitive solution on why this is occurring. This leaves the problem still unsolved without further research/investigation.

The next steps to having a better understanding of this project will involve setting up an experiment. A high pressure high temperature drilling machine would have to be identified and utilized. A drilling machine owned by the United States Department of Energy located in Pittsburgh, Pennsylvania exists with this capability. Through utilization of a machine like this all the conventional ROP variables can be held constant while changing mud formulations. The effect on penetration rate can be measured and corresponded to specific changes in mud formulation.

The first variable to try is the filtrate rate. The filtration rate of the water base mud is higher than the oil base mud, but no good correlation could be made by examining the water base mud’s filtrate rate versus penetration rate. Hopefully through an examination of API filtrate for both the mud types as compared to penetration rate can be obtained.

Oil base mud still maintains advantages over water base in this environment such as it's high temp rheology, contaminant tolerance, inhibition to shale, corrosion protection, and lubricity. Therefore the goal of any future research would be to determine the exact fluid property that the water base possesses that is responsible for this improvement in performance and adapt an oil base fluid. Then all the advantages that oil base possesses can still be maintained and the performance characteristics of water base can be obtained.

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APPENDIX

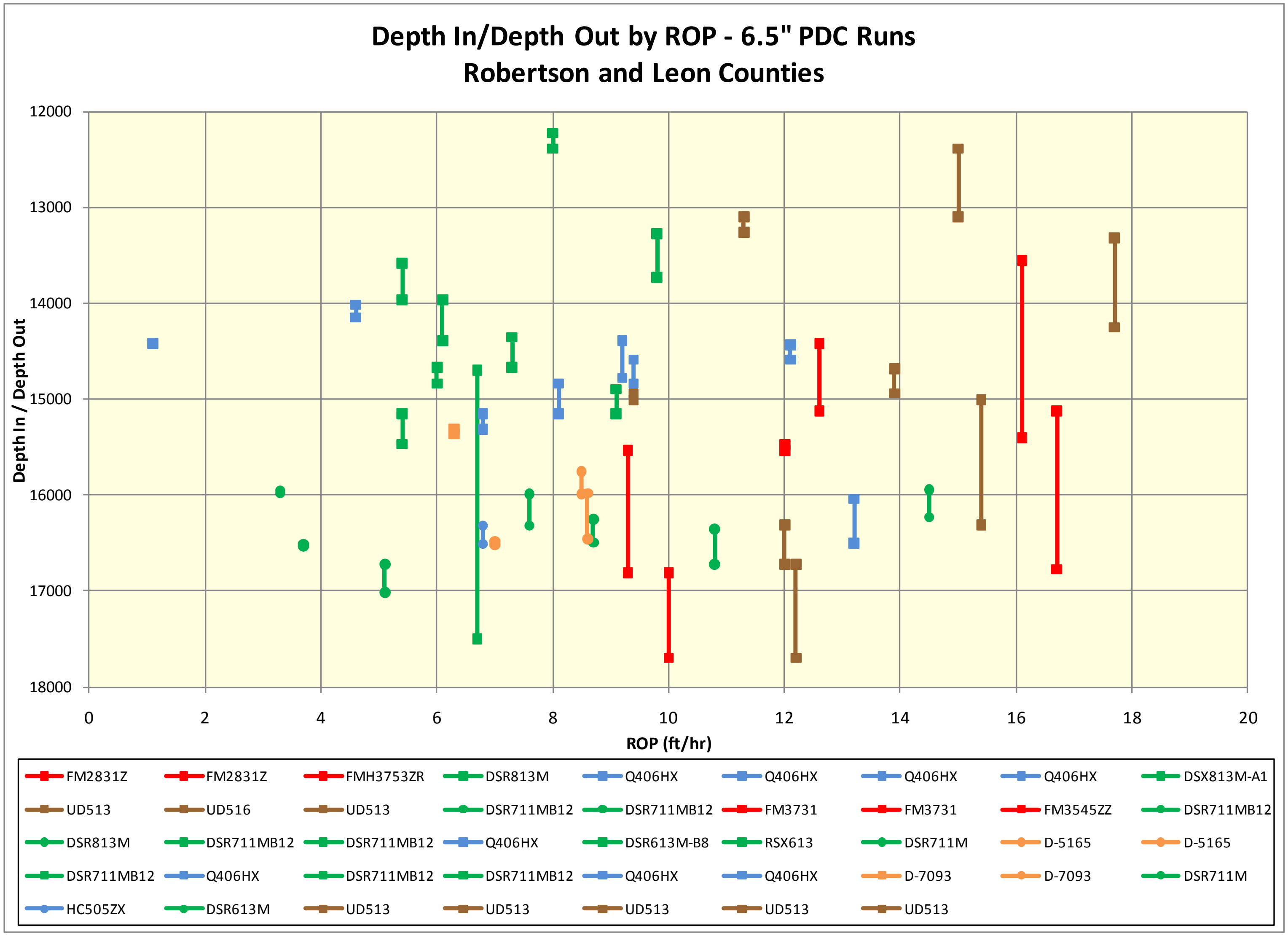

Figure 6: 6.5in PDC Runs Robertson/Leon Counties

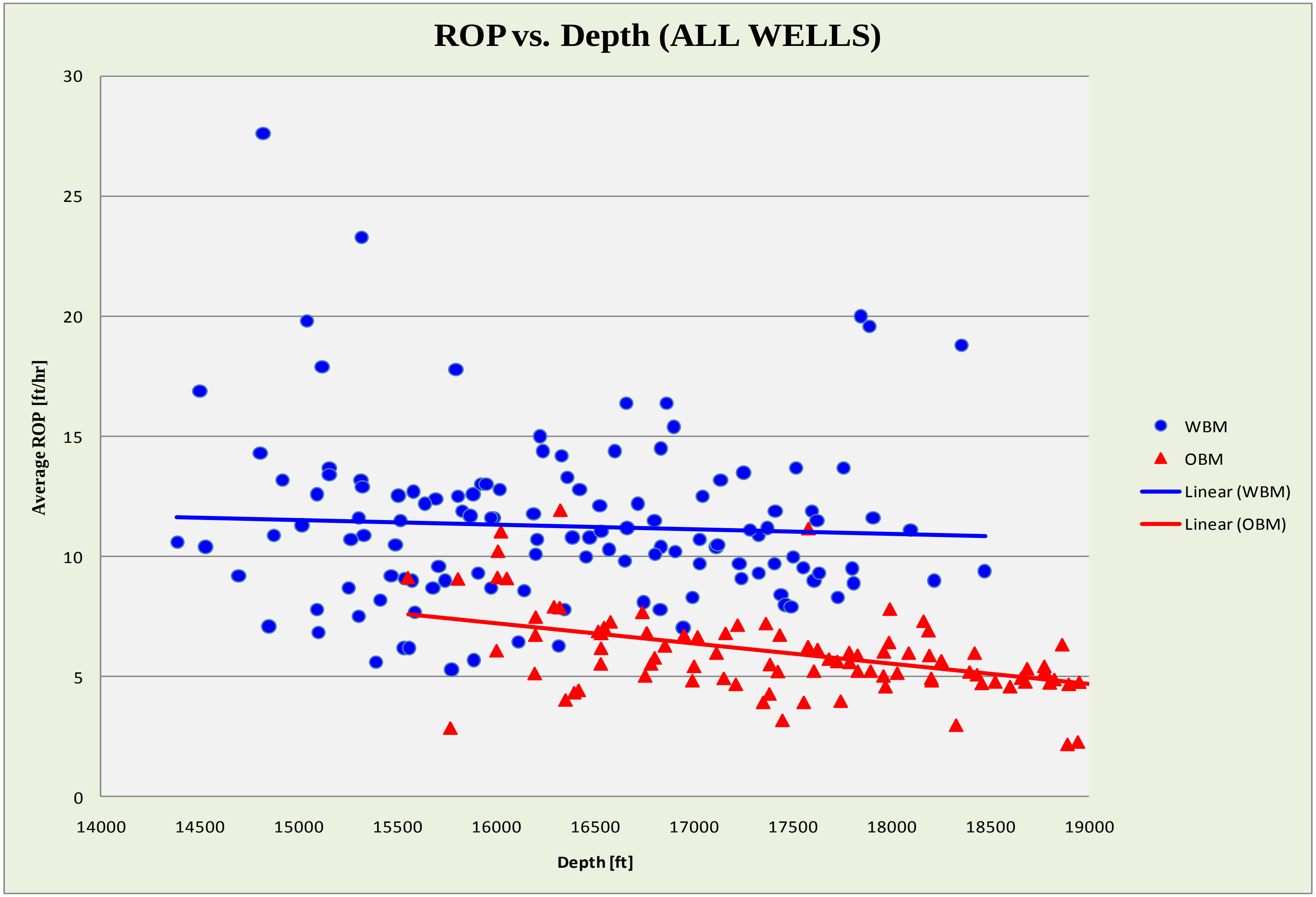

Figure 7: ROP vs. Depth for All Wells

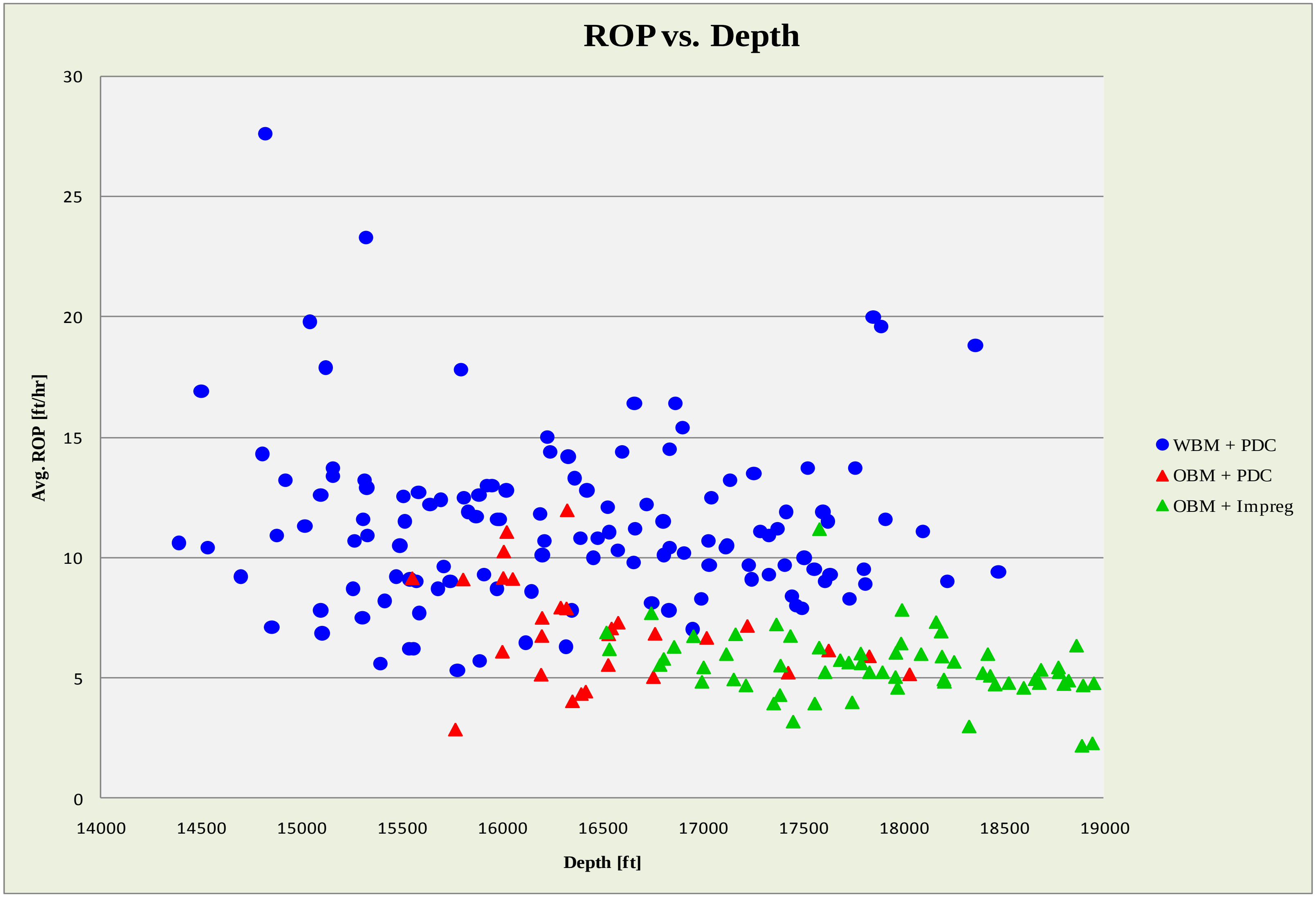

Figure 8: ROP vs. Depth for All Wells by Bit Type

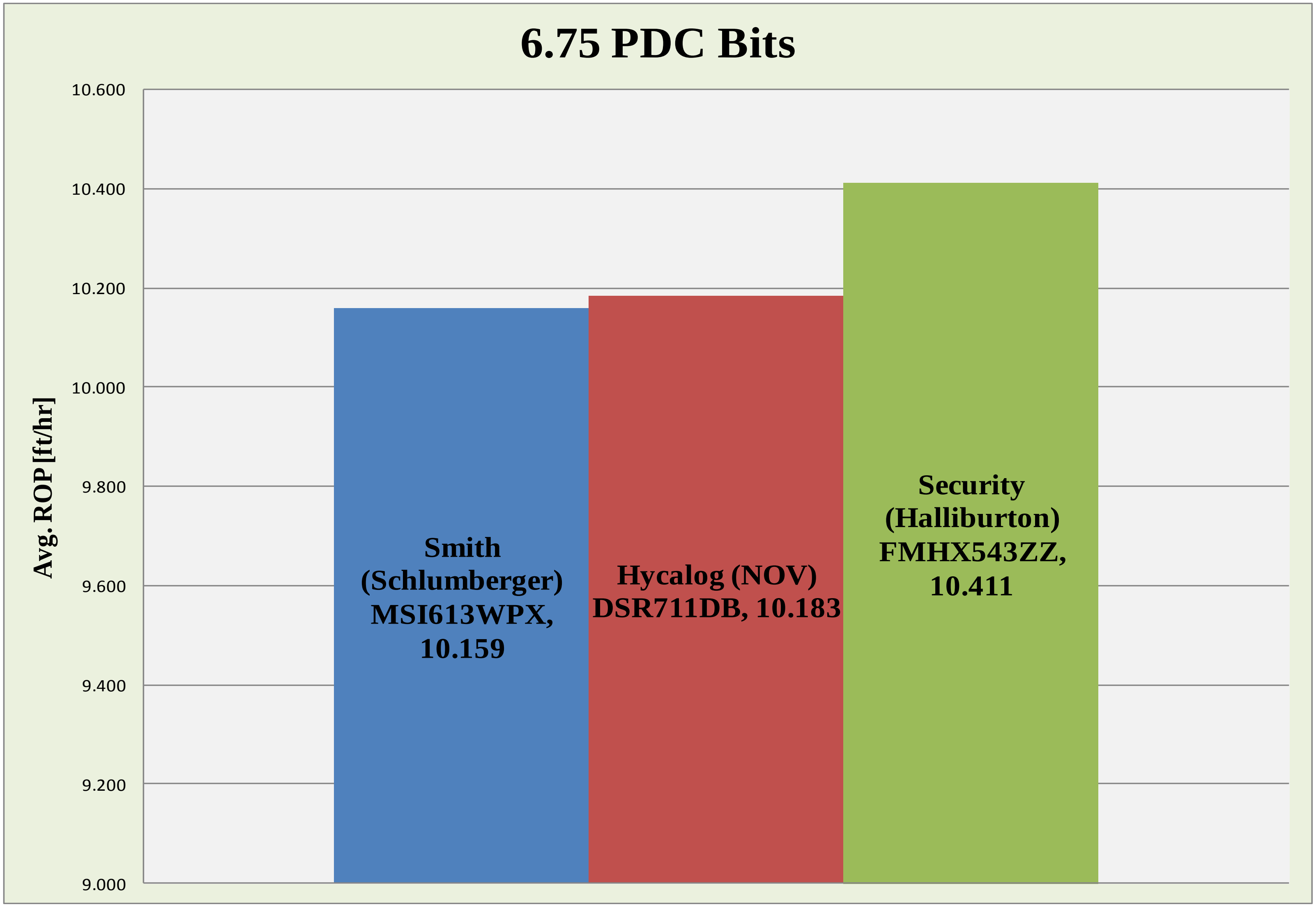

Figure 9: Average Penetration Rates of Most Common PDC Bits in WBM

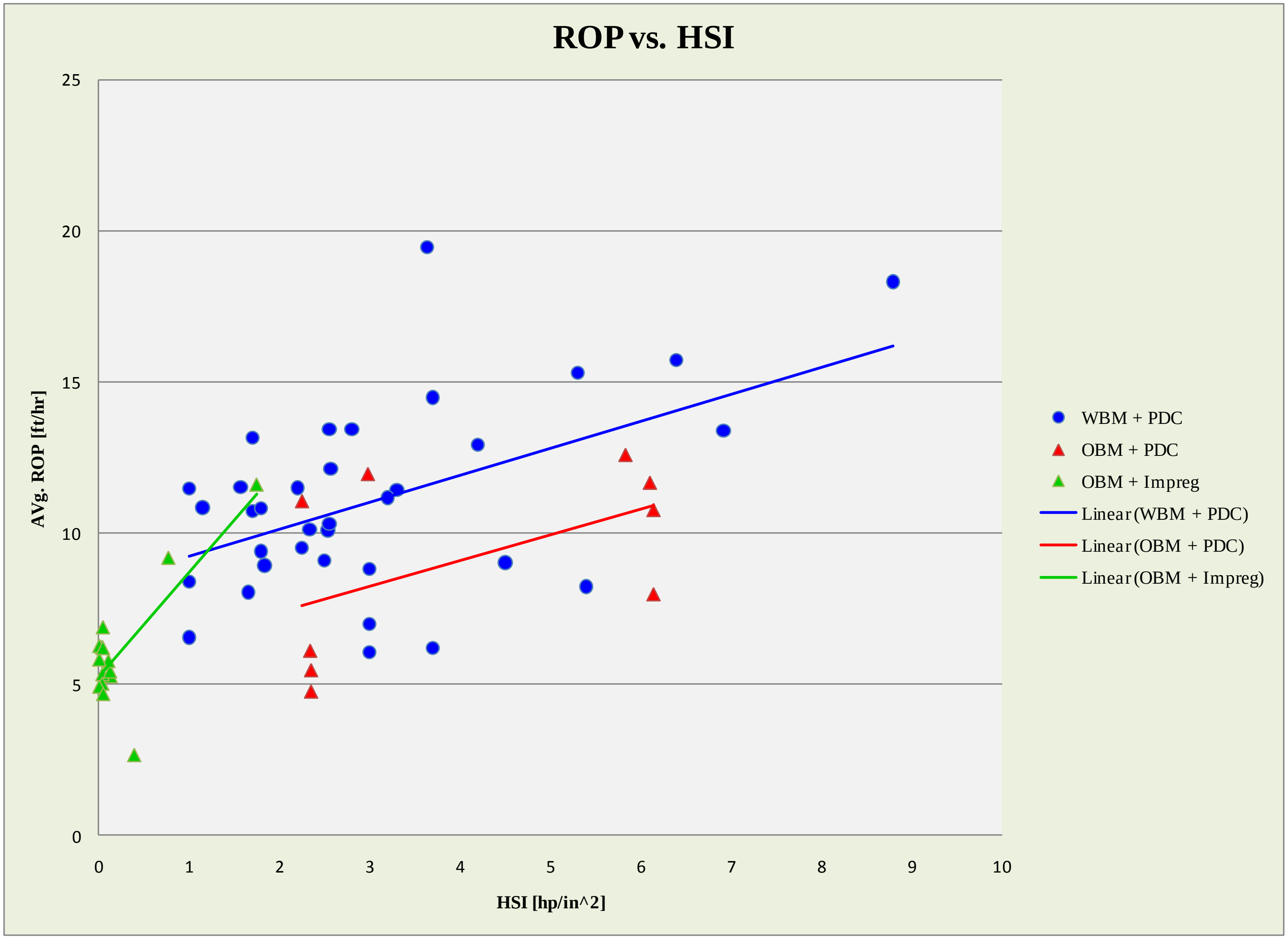

Figure 10: ROP vs. HSI by Bit Run for All Wells

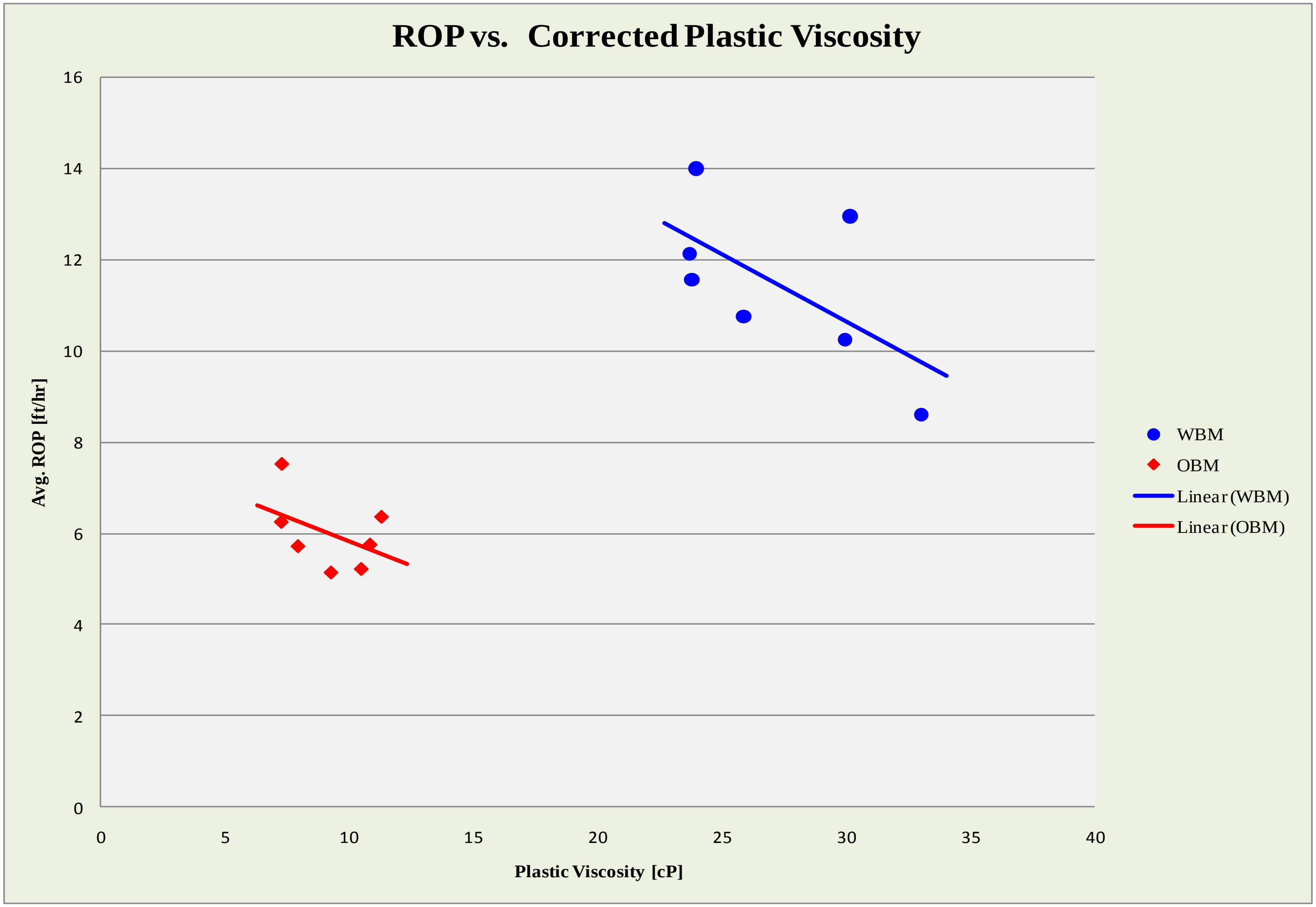

Figure 11: ROP vs. Plastic Viscosity with Corrected OBM PV Values

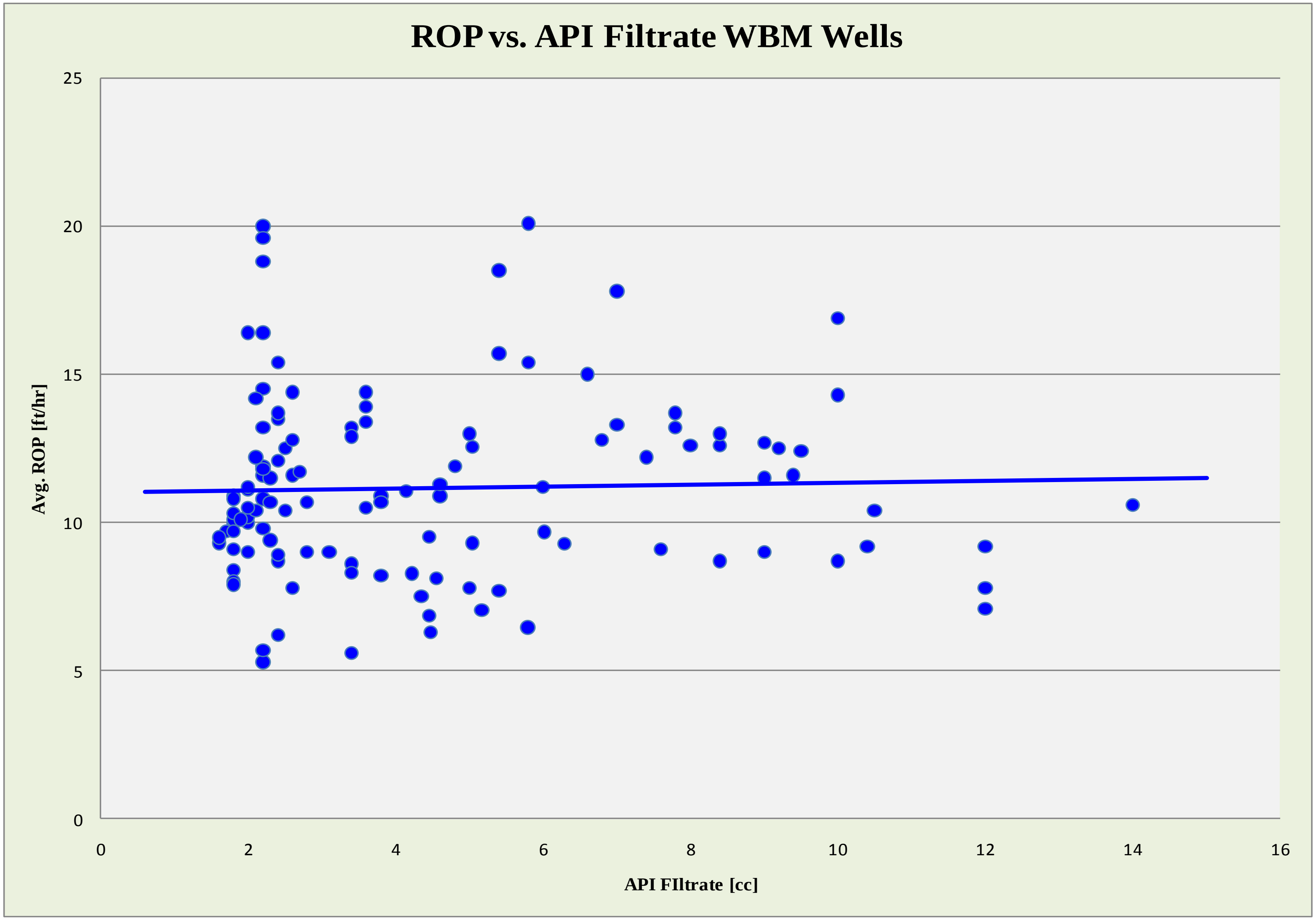

Figure 12: ROP vs. API Filtrate for all WBM Wells

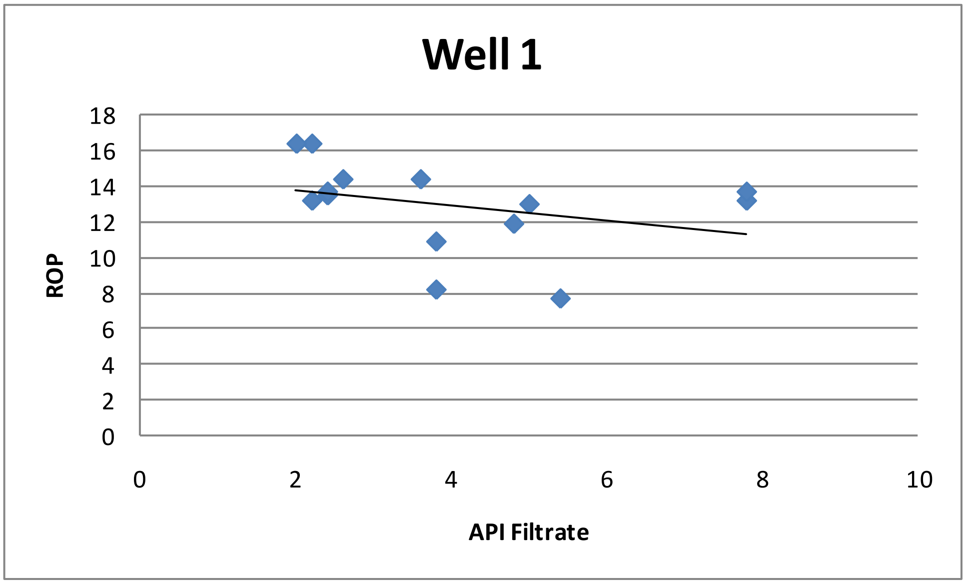

Figure 13: ROP vs. API Filtrate for Well 1

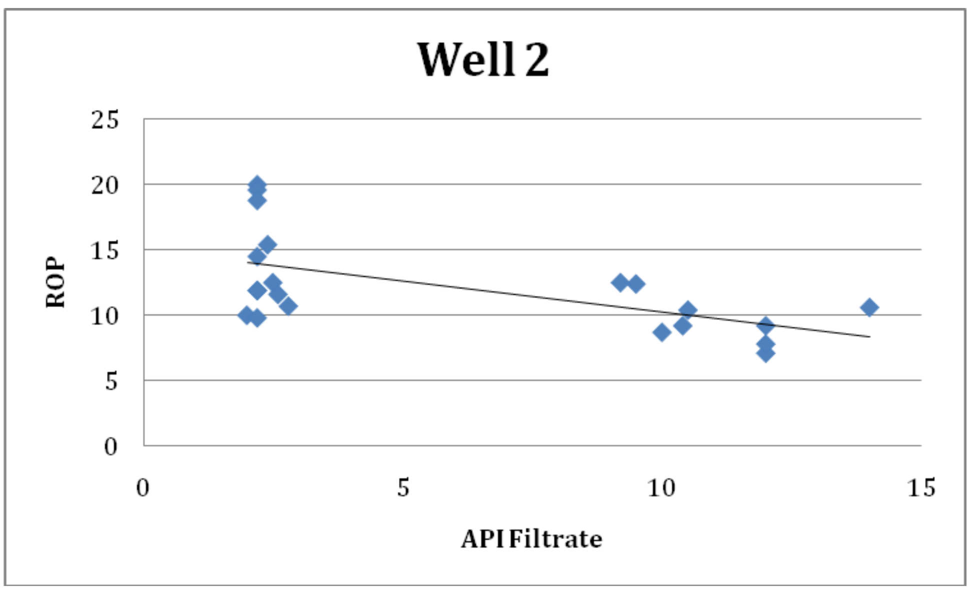

Figure 14: ROP vs. API Filtrate for Well 2

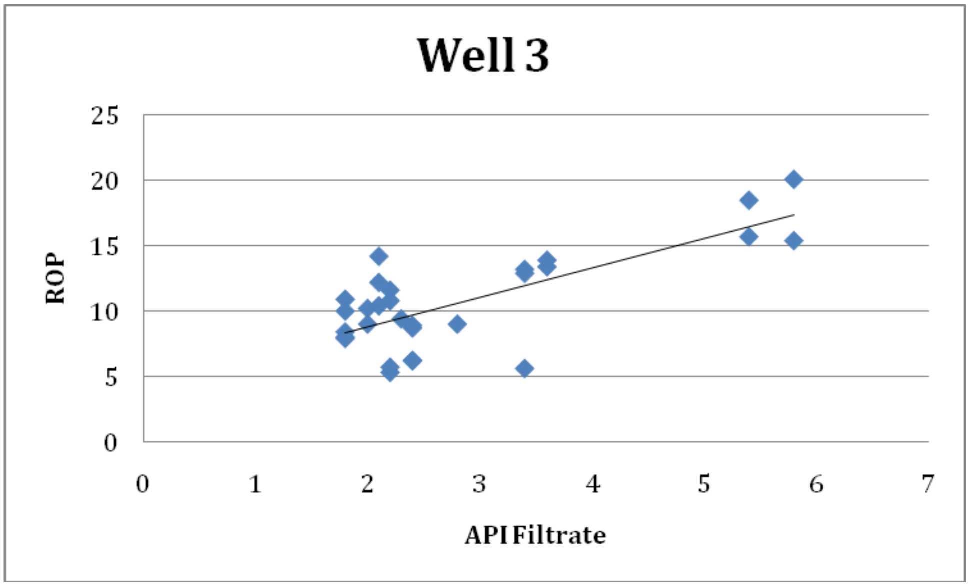

Figure 15: ROP vs. API Filtrate for Well 3

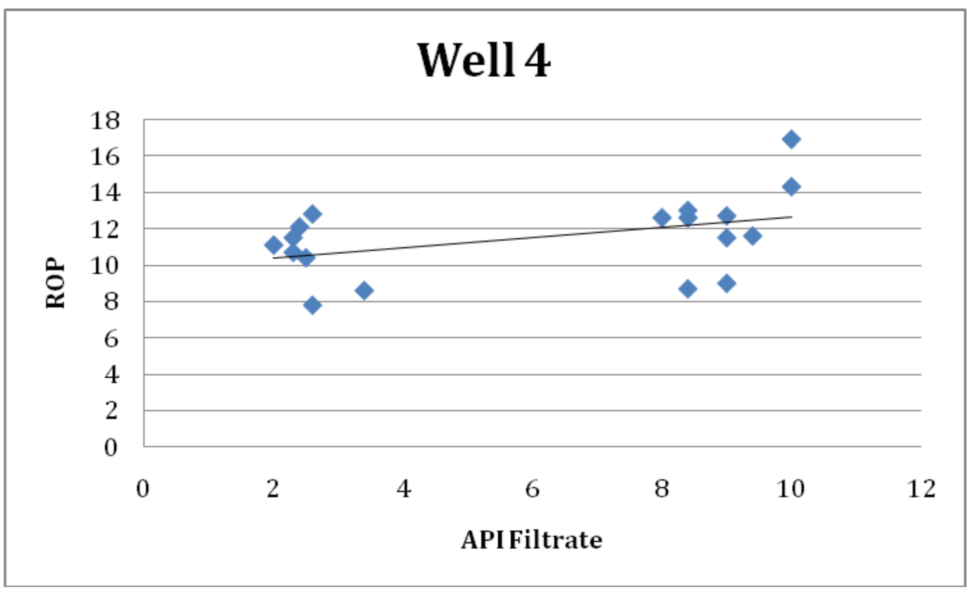

Figure 16: ROP vs. API Filtrate for Well 4

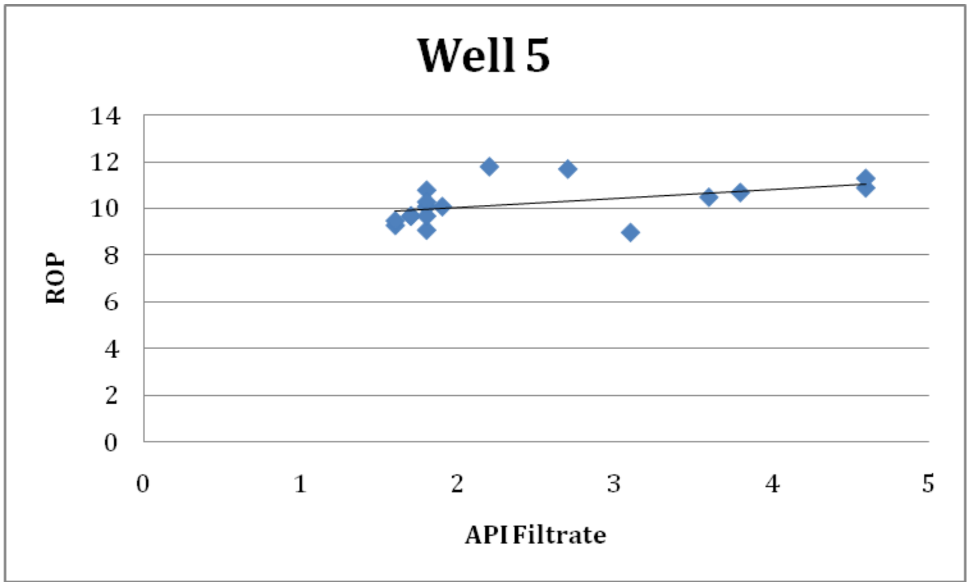

Figure 17: ROP vs. API Filtrate for Well 5

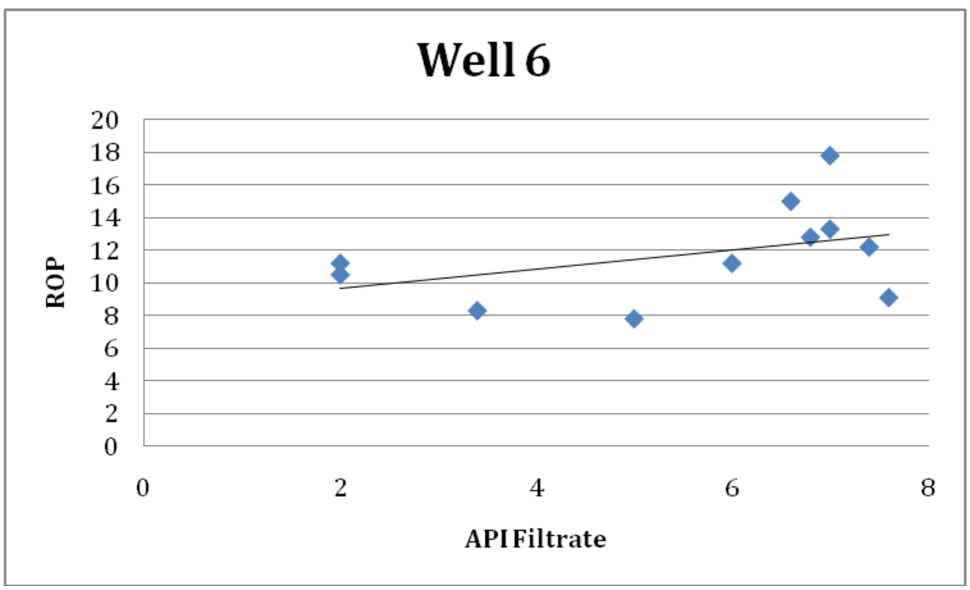

Figure 18: ROP vs. API Filtrate for Well 6

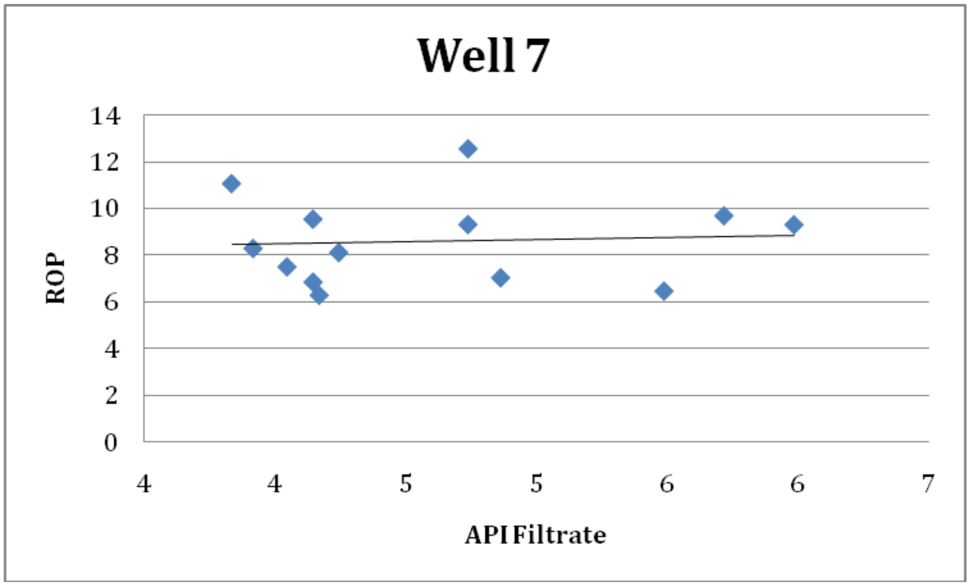

Figure 19: ROP vs. API Filtrate for Well 7

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