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APPLICATION OF ROCK MECHANICS ALGORITHM TO OPTIMIZE DRILLING RATE OF PENETRATION

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A Thesis Submitted in Partial Fulfillment of the Requirements

for the Degree of Master of Engineering Program in Petroleum Engineering

Department of Mining and Petroleum Engineering

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ชาติวิทย์ โพธิ์จันทร์ : การประยุกต์ใช้ขั้นตอนวิธีทางกลศาสตร์หินเพื่อหาค่าอัตราการขุดเจาะที่เหมาะสม (APPLICATION OF ROCK MECHANICS ALGORITHM TO OPTIMIZE DRILLING RATE OF PENETRATION) อ.ที่ปรึกษา:ดร.จิรวัฒน์ ชีวรุ่งโรจน์, 117 หน้า, ISBN 974-53-2590-2

การศึกษานี้มีวัตถุประสงค์เพื่อสร้างแบบจำลองทำนายอัตราการขุดเจาะโดยอาศัยการประยุกต์ใช้ขั้นตอนทางกลศาสตร์หินเพื่อนำไปใช้พัฒนาประสิทธิภาพการขุดเจาะในอ่าวไทย โดยขั้นแรกจะทำการประเมินค่าสัมประสิทธิ์การขุดเจาะซึ่งมีค่าขึ้นอยู่กับประเภทของหัวเจาะแต่ละชนิดที่เลือกใช้ กระบวนการดังกล่าวจะใช้ข้อมูลจากการขุดเจาะและการหยั่งหลุมเจาะจากหลุมทดสอบเพื่อสร้างแบบจำลองการขุดเจาะด้วยโปรแกรมวิเคราะห์ข้อมูลทางกลศาสตร์หิน จากนั้นจะนำวิธีวิเคราะห์ทางสถิติมาประยุกต์ใช้กับแบบจำลองที่สร้างขึ้นเพื่อนำข้อมูลที่ได้ไปเปรียบเทียบกับผลที่ได้จริงจากหลุมทดสอบ

จากกระบวนการการศึกษาก่อนหน้า แบบจำลองการขุดเจาะถูกสร้างขึ้นด้วยค่าสัมประสิทธิ์การขุดเจาะที่เหมาะสมร่วมกับข้อมูลความแข็งของชั้นหิน ความดันเนื่องจากการกดทับ ความดันเนื่องจากของไหลในแหล่งกักเก็บและข้อมูลจากการขุดและหยั่งหลุมเจาะจากหลุมทดสอบ ในขั้นสุดท้ายแบบจำลองค่าอัตราการขุดเจาะและพารามิเตอร์ของการขุดเจาะที่เหมาะสมจะถูกกำหนดขึ้นที่แต่ละระดับความลึกของหลุมเจาะ นอกจากนั้นแบบจำลองยังสามารถแสดงบริเวณของชั้นหินที่มีการกัดกร่อนสูงซึ่งสามารถนำไปปรับพารามิเตอร์ของการขุดเจาะระหว่างการขุดเจาะจริงเพื่อยืดอายุการใช้งานของหัวเจาะได้

ผลที่ได้จากการนำแบบจำลองการขุดเจาะไปประยุกต์ใช้กับการปฏิบัติการจริงแสดงให้เห็นถึงค่าเฉลี่ยของอัตราการขุดเจาะที่มีแนวโน้มเพิ่มสูงขึ้นเมื่อเปรียบเทียบกับหลุมทดสอบ อีกทั้งยังสามารถใช้หัวขุดเจาะเพียงหัวเดียวเพื่อขุดเจาะให้ถึงระดับความลึกเป้าหมายซึ่งถือเป็นสิ่งที่ประสบความสำเร็จที่ได้จากการทดลองเนื่องจากช่วยลดต้นทุนของหัวเจาะและเวลาในการเช่าแท่นขุดเจาะ

แบบจำลองอัตราการขุดเจาะที่เหมาะสมที่ได้จากการประยุกต์ใช้ขั้นตอนทางกลศาสตร์หินเป็นเครื่องมือที่มีประโยชน์เมื่อใช้ร่วมกับการวิเคราะห์แบบค่าใช้จ่ายต่อความลึกในการปฏิบัติการจริง โดยผู้ปฏิบัติงานสามารถใช้แบบจำลองเพื่อช่วยในการตัดสินใจการวางแผนการขุดเจาะระหว่างการขุดเจาะและการประมาณค่าใช้จ่ายในการขุดเจาะ

ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม	ลายมือชื่อนิสิต Chatwit Pochan
สาขาวิชาวิศวกรรมปิโตรเลียม	ลายมือชื่ออาจารย์ที่ปรึกษา [signature]
ปีการศึกษา 2548	

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KEY WORD: /ROCK MECHANICS/DRILLING/RATE OF PENETRATION /OPTIMIZATION

CHATWIT POCHAN : ROCK MECHANICS ALGORITHM TO OPTIMIZE DRILLING RATE OF PENETRATION. THESIS ADVISOR : JIRAWAT CHEWAROUNGROAJ, Ph.D. 117 pp. ISBN 974-53-2590-2

This study aims to generate predicted drilling rate of penetration (ROP) model based on rock mechanics algorithm concept in order to improve drilling performance in the Gulf of Thailand. The first step of the study is to determine the bit sliding coefficient value which is depended on particular selected drilling bit. This process of work utilizes drilling and wireline logging data from an offset well to construct Rock Mechanics Algorithm (RMA) model with RMA software. After that, statistical analysis method is brought into this stage to facilitate in data matching result.

The drilling optimization model is constructed in RMA model with an appropriate bit sliding coefficient value derived from the previous process. In this procedure, Unconfined Compressive Strength (UCS), Overburden pressure, Fluid pore pressure, and drilled&wireline log recorded are input into the program. Finally, Specific Energy Rate of Penetration (SEROP) which is a potential maximum ROP scheme is generated at each wellbore depth. Moreover, RMA model also shows the zone of high abrasivivity formation in order to adjust drilling parameters while drilling to maintain drilling bit life.

On drilling rig site study, SEROP with recommended drilling parameters are oriented to actual drilling operation. The results show the improvement of average ROP comparing to an offset well. A single bit run to Target Depth (TD) is also one of the accomplish result from the bit life study. The major benefits are eliminating redundant drilling bit cost and drilling rig cost from tripping time.

RMA model is a powerful tool using with Cost per Foot (CPF) analysis while conduct drilling operation or encounter critical ROP situation. Drilling RMA model is also helpful for the project well designer and cost estimator.

Department of Mining and Petroleum Engineering Student's signature Chatwit Pochan
Field of study Petroleum Engineering Advisor's signature J. Ch
Academic year 2005

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Nomenclatures

A	area
A_B	borehole area
B	drilling bit cost
D_B	drilling bit diameter
E_S	specific energy
EFF_M	mechanical efficiency
F	applying force
F_{ang}	friction angle
F_t	total footage drilled
G	rock frame rigidity
N	revolution per minute
P_c	critical penetration rate
R	drilling rig operating cost
ROP	drilling rate of penetration
S_o	cohesion force
t	tripping time
T	drilling torque
T_o	formation tensile force
T_r	rotating time
V_S	sonic velocity
WOB	weight on bit

GREEK LETTER

σ	rock stress
μ	bit sliding coefficient
v	poisson's ratio
α	biot's constant
β	angle of internal friction
τ	shear stress
ρ_b	rock bulk density

SUBSCRIPTS

v	vertical
h	horizontal
H	surrounding
ang	angle of friction

Abbreviations

BHA	bottom hole assembly
CCS	confined compressive strength
CDF	cumulative distribution function
DOT	drill-off test
FES	formation evaluation specialist
FIT	formation integrity test
GR	gamma ray
LOT	leak off test
MSE	mechanical specific energy
MD	measure depth
PDC	polycrystalline diamond compact
PLA	petroleum licensed area
RHOB	bulk density
RMA	rock mechanic algorithm
ROP	drilling rate of penetration
RPM	revolution per minute
S-wave	shear wave
SEROP	specific energy rate of penetration
tvdrt	true vertical depth from rotary
tvdss	true vertical depth subsea
TD	target depth
TVD	true vertical depth
UCS	unconfined compressive strength
WOB	weight on bit

CHAPTER I

INTRODUCTION

For years, there are several attempts to minimize drilling costs and improve drilling performances by trying to build models capable of predicting Drilling Rate of Penetration (ROP). Basically, an ROP model has been developed using the concept of mechanical specific energy. This is the energy required to excavate a unit volume of rock. The model requires three steps of work. Firstly, formation compressive strength is estimated from wireline log data, lithology, and downhole pressures and empirical relationship developed from laboratory drilling test data. Secondly, the power transmitted from the bit into rock destruction is calculated from the weight on bit, rotary speed, bit diameter and a sliding coefficient that is itself dependent on bit type and rock properties. Finally, the instantaneous ROP is estimated from the minimum specific energy, the hole size diameter and the power input to rock destruction. For this study, bit sliding coefficient is the objective parameter to optimize drilling ROP.

Rock Mechanic Algorithm (RMA) software offers new methodology which is different from existing ROP prediction methods that are based on Unconfined Compressive Strength (UCS) of the rock formation. The fact is that UCS does not represent the apparent strength of the formation and will finally tend to generate error results. On the other hand, Confined Compressive Strength (CCS) of the rock formation approach better represents the apparent rock strength to the bit. CCS is composed of UCS, hydrostatic pressure due to mud weight while drilling, overburden stress, etc. Using CCS has opened the door to predict more accurate ROP with little or no calibration. Another factor to be considered as a relative drilling parameter control for bit performance model is an internal of friction angle (F_{ang}) of the rock which normally be understood as formation abrasiveness. For this study, three geological parameters which are effect to drilling bit performance will be considered while optimizing drilling parameters namely the UCS, CCS and F_{ang}.

The RMA model is actually composed of two separate models: the Rock Strength Model, which computes rock strength and other rock properties, and the In Situ Stress Model, which assesses in situ stresses acting upon the formation and the effect of these stresses on the formation. The RMA software is designed to be run after routine log analyses have determined formation lithology and fluid content. The RMA program models rock properties using common wireline log data. Sonic or synthetic logs are required. Field data are used to calibrate the model and additional data needed (beyond the basic data needed to run RMA) may include physical rock data, drilling data, production data, and core test data, etc.

1.1 Objective

To determine selected bit sliding coefficient and properly rate of penetration scheme for the drilling operation and well planning by using rock mechanics algorithm process approaching. The offset drilling well is chosen to construct the optimized drilling model and then implement to actual field.

1.2 Outline of Approach

To determine objective drilling parameters and construct optimized drilling model, these are 10 steps to accomplish as follow:

1. Specify petroleum concession area of interest regarding to geological and drilling data are available. For this study, the area is located in the Gulf of Thailand.
2. Gather and refine preliminary available data such as geological background, lithology identification, logging data and drilling parameter data from actual field to be considered as an offset data.
3. Construct drilling well simulation model with RMA process.
4. Simulate drilling well model under formation specific energy concept and compare to offset drilling well data.
5. Verify the results and calibrate the drilling well model by varying drilling parameters such as revolution per minute of drilling (RPM) and weight on bit (WOB) in order to properly match rate of penetration (ROP) between well model and offset data.

6. Determine bit sliding coefficient for a particular selected bit run.
7. Construct new drilling well model with estimated bit sliding coefficient from the previous stage.
8. Simulate model to optimize drilling rate of penetration.
9. Orient the simulated model to actual drilling operation.
10. Make a conclusion and recommendation for the result and give further study aspect.

Figure 1.1 shows the work flow diagram of thesis study as outlined above.

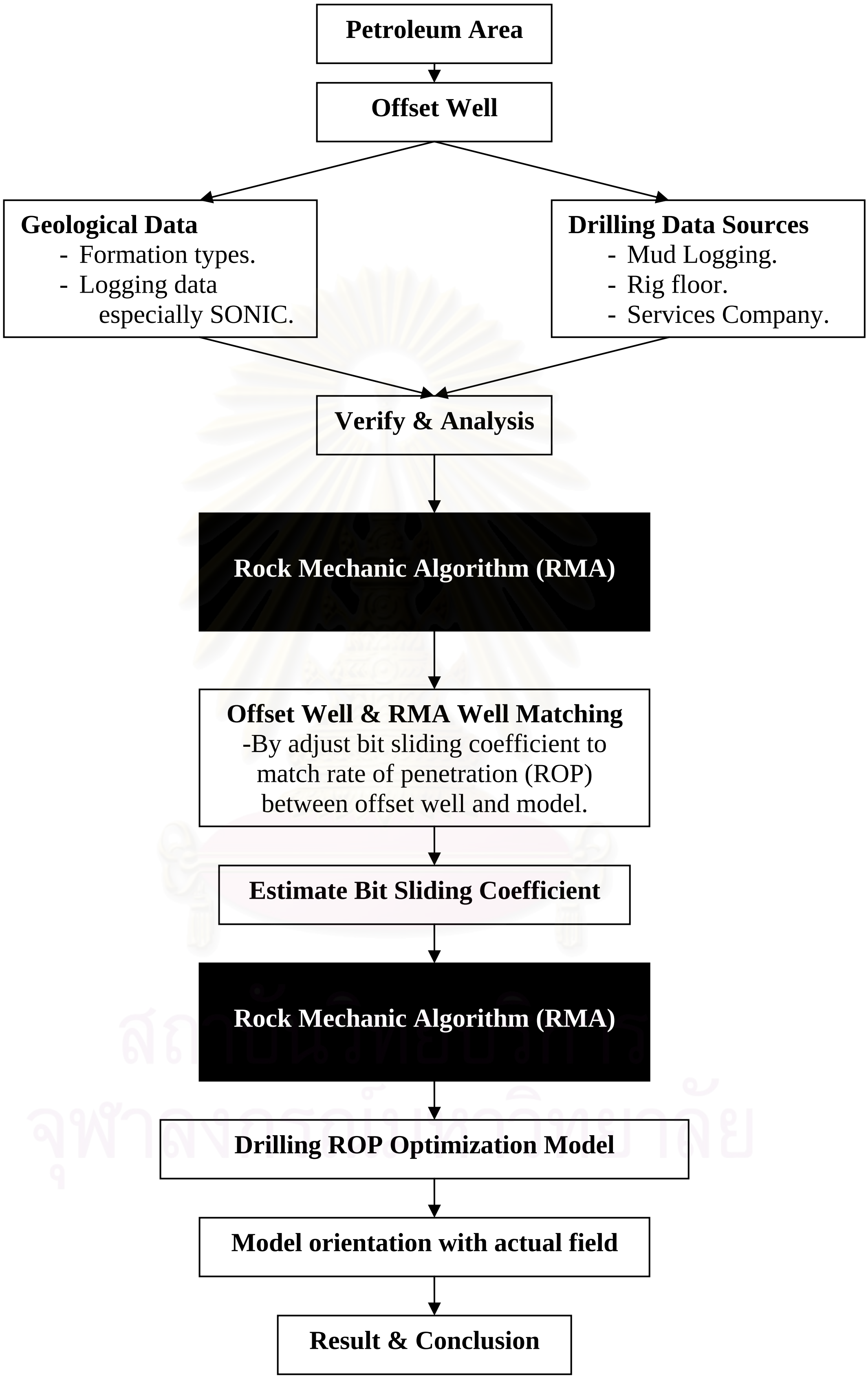

Figure 1.1: Thesis study workflow.

1.4 Thesis Outline

This thesis paper consists of five chapters.

Chapter II reviews previous works on The Rock Strength and Drillability, Formation Abrasivity and Rock Mechanical Energy concerning to this study.

Chapter III introduces the theoretical framework and methodology in this study. This chapter is divided into to sections which are geological part and drilling operation part. RMA model working principal are also discussed in this chapter and model application is also discussed.

Chapter IV presents the study results and discussions from field work model orientation. Summary of the results from each drilling well with observations are also summarized for comparison purpose. Finally, recommendation and improvement from each well case study are discussed and concluded.

Chapter V provides conclusion of the study and recommendation for the further study based on this study point of view.

CHAPTER II

LITERATURE REVIEW

Determination of rock strength is essential to optimize drilling parameter operations. The evolution of the rock strength function and discussion of the rock mechanical properties that impact strength and drillability are discussed in this chapter. The Unconfined Compressive Strength (UCS) is very significant to this discussion. The concept and the estimation techniques used by Rock Mechanics theory and by others for determine UCS are reviewed. The derivation of Confined Compressive Strength (CCS), Angle of Internal Friction (F_{ang}), and other rock mechanical properties are also discussed.

2.1 Background

For year, many endeavors have been made to determine formation strength and drillability by using petrophysical log measurements. Gestalder and Raynal (1966) reported that rock hardness increases as compressional wave velocities from conventional acoustic wireline tools increase. Furthermore, this work noted that rock hardness determined in the laboratory or estimated from acoustic logging might be possible to predict drilling performance.

Somerton (1970) made a further study of Gestalder and Raynal by reported that acoustic log travel times can be correlated with rock drillability in carbonate sand by taken a mineralogical factor into account.

Deinbach (1982) developed a method of selecting drill bits using sonic and gamma ray logs from nearby wells. He observed that the sonic log response to porosity was closely related to rock strength. When shale content was included, via the gamma ray log, bit selection was performed. Actual rock mechanical properties were not calculated. The relationships Deinbach documented were only qualitatively expressed.

Mason (1984) reported that formation compressive strengths increase as calculated formation shear wave (S-wave) velocities increase. A correlation was made between conventional roller cone bit economic performance from various offset wells and calculated S-wave travel times. Mason's method for calculating formation S-wave velocities is extremely dependent upon mineral composition and an idealized table of P-wave/S-wave velocity ratios.

Onyia (1988) studied the relationship between rock strength and some of wireline log properties to estimate rock drilling strength. Laboratory measured rock core strengths were correlated to wireline acoustic and resistivity data. The core/log-derived strengths were then related to the drilling performance of roller cone bits at a nearby test well. Onyia stated that, given a formation’s rock strength and drilling parameters, approximate drilling rates could be predicted.

2.2 Rock Strength Estimation and Drillability

This section presents the previous works on Rock Strength Estimation, Clay and Shale Effect, and Formation Abrasivity Estimation.

2.2.1 Previous Works on Rock Strength Estimation

Stein and Hilchie (1972) proposed the relation of Rock Frame Rigidity (G) and Incompressibility (Kb) to be more closely related conceptually to Unconfined Compressive Strength (UCS) than to shear wave velocity. Equation 2.1, relates shear wave velocity (Vs) with rigidity. Rock strength has also been linked to rigidity or rock stiffness. A strength function linking shear wave velocity to rock strength is also linked to Rock Frame Rigidity.

$$V_s = \sqrt{\frac{G}{\rho_b}} \tag{2.1}$$

where V_s = Sonic velocity, fps

G = Rock frame rigidity, gPa

ρ_b = Rock bulk density, gm/cc

Rock strength has also been shown to increase as porosity decreases. J. Gustkiewicz (1989) studied the relation between porosity and rock strength and presented the plot of core test results shown in Figure 2.1 demonstrates this fact.

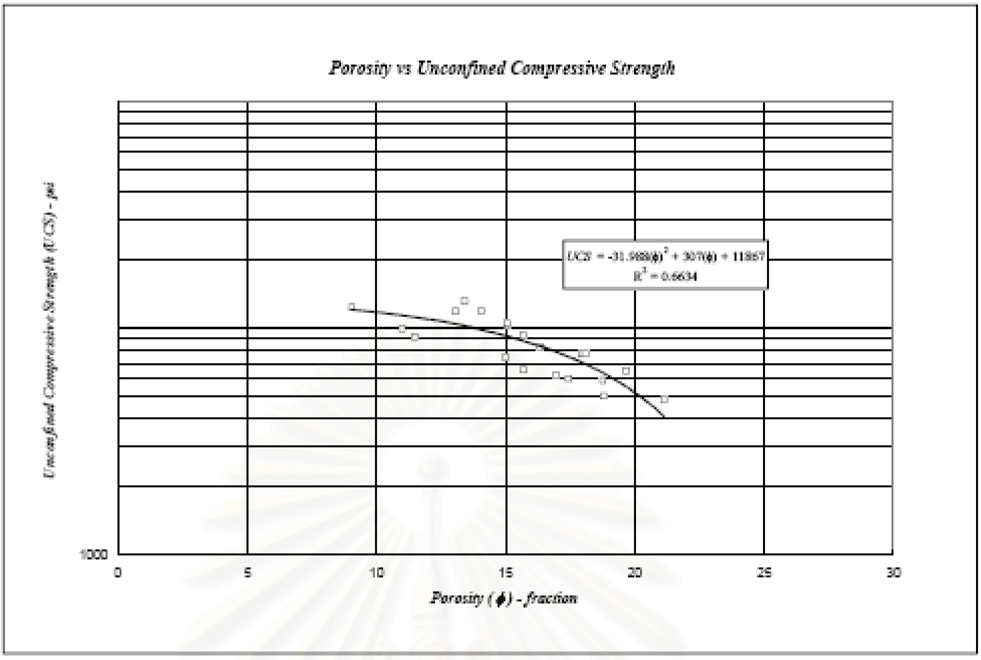

Figure 2.1: Porosity versus Unconfined Compressive Strength (UCS) plot from core measurements, (J. Gustkiewicz, 1989).

As porosity decreases, the ratio of dry frame modulus (K_A) to solid grain modulus (K_S), (K_A/K_S), which is a measure of rock stiffness. This behavior has been recognized from measurements performed on granitic rocks, limestone, refractory shale and sandstones. Figure 2.2 displays porosity versus K_{dry}/K_{ma} (identical to K_A/K_S) for dolostone formation. In this figure, rock stiffness is observed to increase with reduced porosity. Because of the inverse relationships between porosity and rock elastic moduli and between porosity and rock strength, a logical conclusion is that rock strength increases as the elastic moduli increase.

Generally, the planner has used the carry out of using UCS for bit selection criteria, performance prediction and operation planning. This assumption may be fit for formation drilled with clear drilling fluid which is normally only a small part of the rock drilled in one particular well. On the other hand, the use of Confined Compressive Strength (CCS) of rock is more useful and accurate to approach performance optimizations.

Currently, there is broadly acknowledged method for calculating rock CCS based on rock UCS, confining stress, pore pressure, and rock internal angle of friction.

The technique is a common rock mechanics approach. This CCS approach can provide a more realistic representation of apparent rock strength to the bit than UCS.

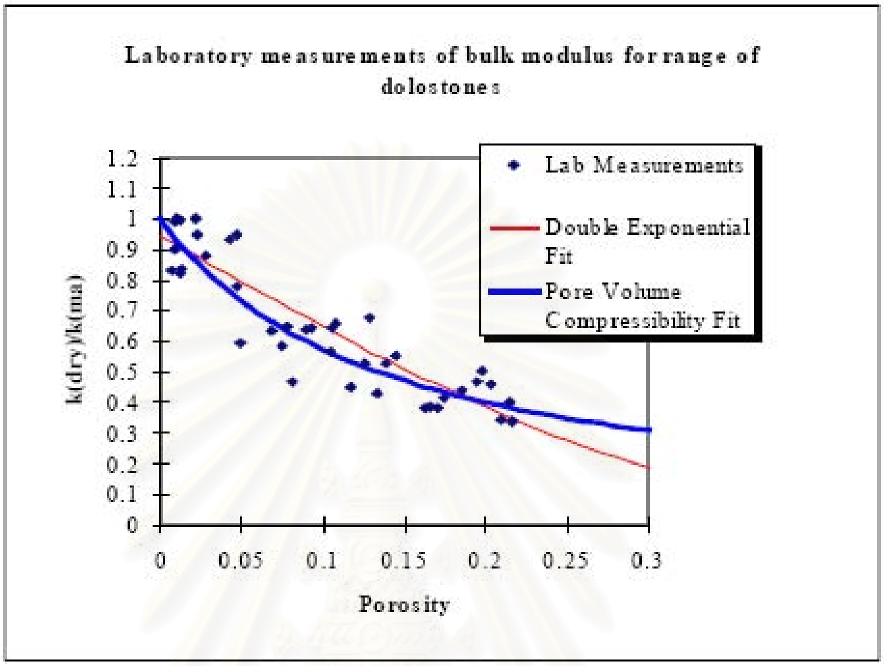

Figure 2.2: Elastic frame moduli for dolostone relative to porosity, (J. Gustkiewicz, 1989).

2.2.2 Effect of Clay and Shale to Rock Strength

As soft clay or soft shale distribution changes from disseminated or grain lining as shown in Figure 2.3, the rock frame or rock skeleton becomes more rigid. Rock Frame Rigidity increases and strength increases. Conversely, increases in grain lining weak clay and shale content causes a decrease in rigidity and a decrease in strength.

However, increasing clay or shale content as a discontinuous phase will leave the rock frame rigidity relatively unchanged, which in turn preserves rock strength.

Presently, some of rock strength models also use the concept of Shale/Clay distribution to estimate rock strength. The modeling approach depends upon whether the grains are touching and shale/clay distribution is discrete or whether the grains are "floating" in the shale/clay matrix, i.e., the shale/clay phase is the continuous matrix. Two rock strength clusters are modeled.

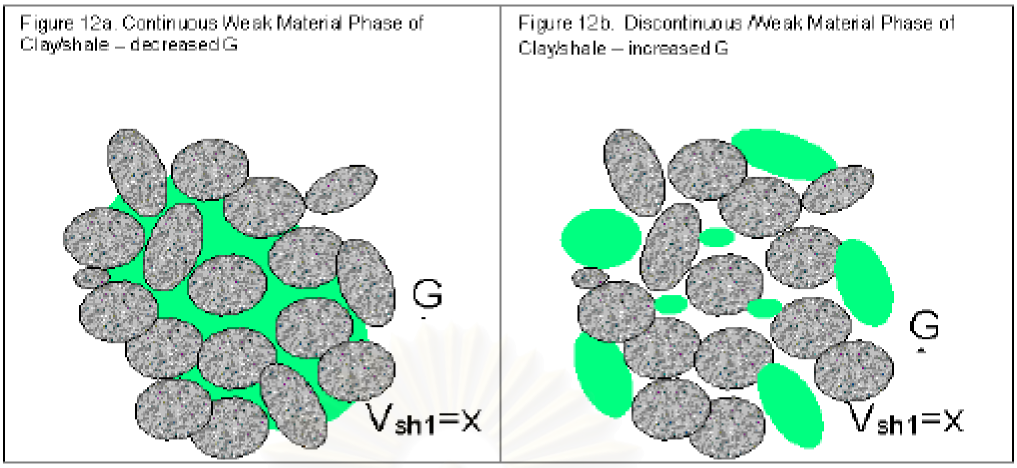

Figure 2.3: The effect of Clay/Shale distribution on formation rigidity.

For this study, program uses the shear wave velocity (V_S) to describe UCS. This approach is taken since current logging technology does not provide direct measurement of either the frame moduli or rock strength.

The current function of V_S-UCS function was revised in 1997 using C. Bovberg's and R. Ewy's measurements of unconfined compressive strength and shear wave velocity. H. Goodman created the original strength function in April 1988. Goodman's function used Mason's idea of relating shear wave velocity to unconfined compressive strength (Mason, 1987). Mason developed the notion of using shear wave velocity to assess compressive strength, and ultimately related roller cone bit type selection directly to shear wave travel time. However, his shear wave velocity estimation technique is primitive by this study standard.

2.2.3 Previous Works on Formation Abrasiveness Estimation

Turk and Dearman (1986) developed an expression for the angle of internal friction. The function predicts that as Poisson's ratio (ν) changes with changes in water saturation and shaliness, the angle of internal friction (F_{ang}) changes. (Note, the angle of internal friction is also related to rock drillability and therefore to drill bit performance.) This definition of friction angle has been found to be quite useful for comparing formation materials according to angle of internal friction and for relating friction angle to abrasivity. Consequently, friction angle rankings from the least to highest values are:

$$F_{ang.\,(Shale)} < F_{ang\,(Limestone)} < F_{ang\,(Dolostone)} < F_{ang\,(Sand)}$$

This ranking of F_{ang} from least (shale) to highest (sand) corresponds to abrasivity rankings from least (shale) to highest (sand) and in the same order. Accordingly, the degree of abrasivity is valuable in drilling operations especially in bit life concerning. From an offset log and formation data, operator could possibly plan drilling parameters to deal with the variable degree of rock abrasiveness in order to minimize worning problem and prolong bit life.

2.3 Rock Mechanical Energy Properties

A simplified approach to optimize drilling rate of penetration in this study is based on Mechanical Specific Energy (MSE) of rock concept. MSE theory has been derived, utilized and published for years with experimental data and actual field data. This section reviews proposed theories and previous work on MSE of rock.

2.3.1 Specific Energy Theory

Teale (1965) derived The Specific Energy (E_S) in rotary drilling as the following equation:

$$E_S = \frac{WOB}{A_B} + \frac{120\pi NT}{A_B ROP} \tag{2.2}$$

where E_S = Specific Energy, psi
WOB = Weight on Bit, lbf
A_B = Borehole Area, in^2
N = Revolution per Minute, rpm
T = Torque, lbf-in
ROP = Rate of Penetration, ft/hr

He also introduced the concept of the minimum specific energy and/or maximum mechanical efficiency that the minimum specific energy is reached when the specific energy roughly approaches the compressive strength of the rock being drilled but cannot be demonstrated in a single accurate number because the drilling process is conducted under wide fluctuations of the drilling variables. However, he conducted his experiment under atmospheric condition.

Rabia (1985) defined the specific energy as the energy required to remove the unit volume of rock. He concluded that the specific energy is not a fundamental or intrinsic property of rock but it is highly dependent on bit type and design characteristics by the following equation:

$$E_S = k\frac{WN}{DR} \tag{2.3}$$

where E_S = Specific Energy, psi

k = constant, dimensionless

W = Applied Weight on Bit, lbf

N = Rotary Speed, rpm

D = Bit diameter, in.

R = Penetration Rate, ft/hr

For a given formation compressive strength, soft formation bit will produce a totally different amount of input Specific Energy $(E_S)_{input}$ when compare to hard-formation bit will. By this property of E_S, therefore, selecting an appropriate bit type and design will achieve high drilling performance result. He also demonstrated the relationship between input specific energy and cumulative cost per foot of drilling irrespectively rig cost and trip time as shown in the Figure 2.4 by drilling bit that give the lowest E_S is taken as the most economical bit. This concept is convenience to drilling engineer for bit selection criteria.

Pessier and Fear (1992) proposed the concept of specific energy in rock drilling by using the Full-scale simulator testing and the interpretation of field data demonstrating the value of mechanical and energy-balanced model while drilling under hydrostatic pressure. The model can be used to improve and interpret drilling data in the detection and correction drilling problems, analysis and optimization drilling practices, bit selection and further development of expert system, etc. Their study also based on Specific Energy Concept which was derived and proposed by Teale earlier.

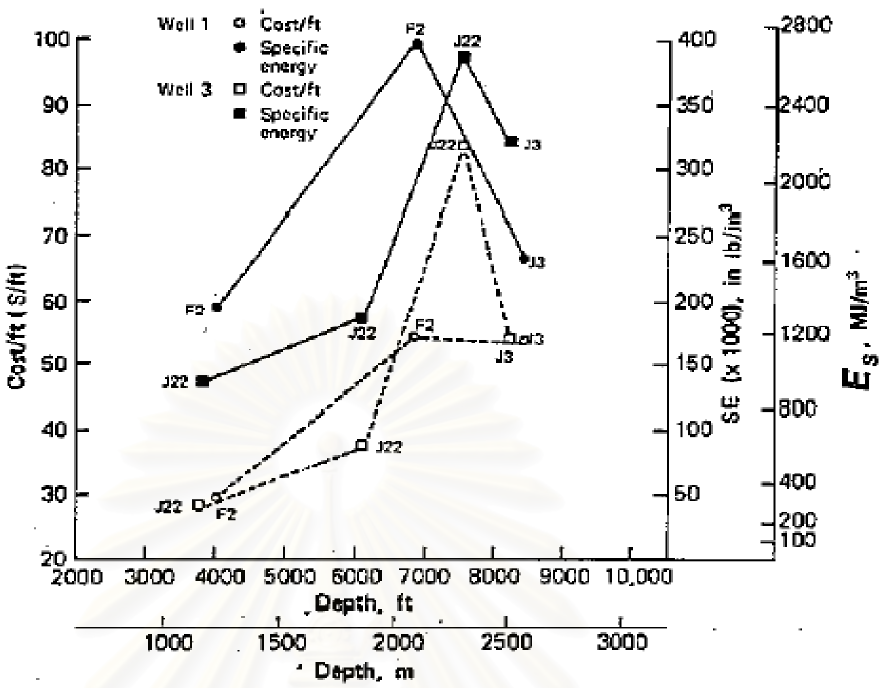

Figure 2.4: Relationship between cumulative cost per foot of drilling and specific energy for a given hole section (Rabia, 1985).

They also conducted the experiment to investigate Bit Sliding Coefficient (μ) for 7-7/8” Tungsten Carbide Insert (TCI) bit. Results shown the wide range of values which was depended on types of formation had been drilled. In grout drilling simulator test, μ was observed in the range of 0.16 to 0.23 while the value of 10 was derived from drilling in Mancos shale. However, the results from both tests demonstrated the similar drilling characteristics by gaining higher ROP when approaching E_S or rock strength which was supported their primary hypothesis and specific energy equation.

Next chapter presents theoretical framework and methodology of this study which are Rock stress and strength relationship, RMA geological and drilling model construction processes, and specific energy theory with drilling operation application.

CHAPTER III

THEORETICAL FRAMEWORK AND METHODOLOGY

This chapter presents theory and principal of rock mechanics and rock specific energy concept applying to drilling operation and planning. The study methodology and application are also provided and discussed in this chapter.

3.1 Rock Stress

Understanding the drilling optimization process is the perceptive of the character and behavior of rocks that make up the formation. The concepts include stresses that can be acting upon a rock, rock strength and the interactions between stress and strength. The basic stress and strength terms and concepts are also briefly reviewed in this section, including the types and sources of stresses, the physical and mechanical properties that contribute to rock strength.

3.1.1 Stress

Stress is a magnitude of the force applied to a unit surface area. Stress can be oriented into or away from the rock. The application of stress to a rock causes changes in the rock and can cause deformation or destruction of a rock. Stress can be expressed as:

$$\sigma = \frac{F}{A} \tag{3.1}$$

where σ = Stress, psi

F = Force, lbf

A = Area, in^2

Stresses are tensor which have both magnitude and direction. Figure 3.1 shows how an applied force can create different stress levels. In this example, the area changes while the magnitude of the force remains constant at each area. Since stress equals to the force divided by the area then the magnitude of stress changes as the size of each area changes. The stress on Area 2 is greater than the stress on Area 1, and is even greater at area 3, which is an area approaching a point in space.

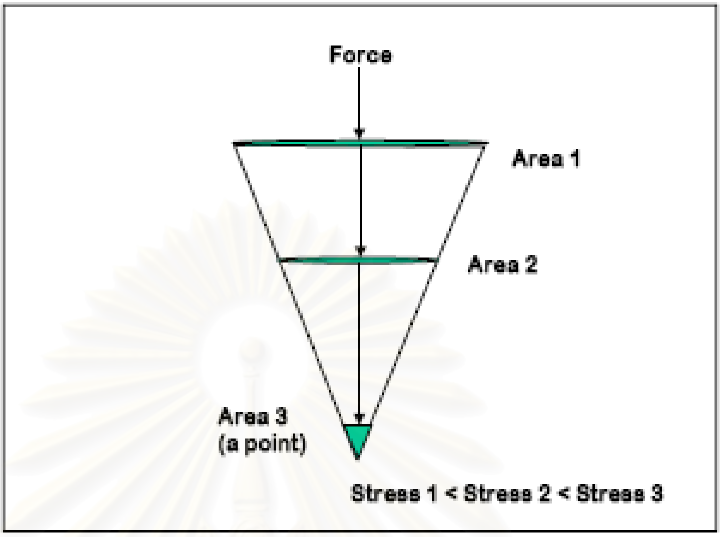

Figure 3.1: Different stress magnitude by variable applied area.

In the nature, rock is applied by forces from many directions. The most accuracy way to represent rock stress is to consider rock cube model in three dimensions as shown in the Figure 3.2.

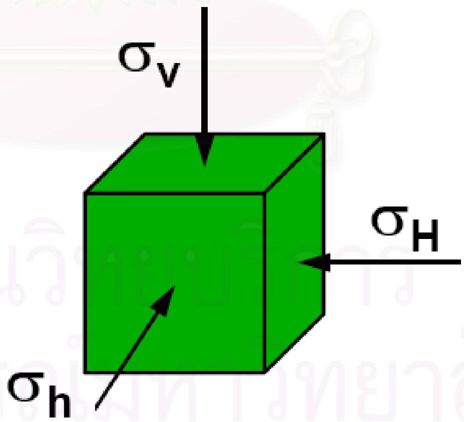

Figure 3.2: Stress in x-y-z coordinates.

Typically, the right-handed system of rectangular axes is used to define the positive and negative direction of the stresses. In the natural (in situ) state, rocks are usually being compressed due to the weight of the overburden. For this reason, the study considers stress in the compressive direction into the rock to be positive but negative stress is an outward-oriented stress or a rock in tension.

3.1.2 Types of Stress

Types of stress are categorized in three types as follow:

a) Vertical Stress, σ_v

Vertical stress in the pre-drilled structure is mainly due to gravitational forces. The weight of the overlying strata above the depth of interest together with the fluids they contain is the primary cause of this stress which is called overburden stress. The other sources of vertical stress include stresses that may result from such geologic conditions as magma or salt dome intrusion in the vicinity of the formation. The magnitude of the vertical stress is the sum of all vertical stresses acting on a rock but for most rock mechanics applications it is generally considered to be equivalent to the overburden stress. In this study, the overburden stress is calculated by integrating the density log from the depth of interest to the surface by following equation:

$$\sigma_v = \int \rho_b(h)dh \tag{3.2}$$

where σ_v = Overburden Stress, psi

ρ_b = Rock bulk density, psi/ft

h = Depth of Interest, ft

b) Horizontal Stress, σ_h

Horizontal stresses are the result of forces oriented perpendicular to each other in a horizontal direction. Horizontal stress may come from many sources. One important source of horizontal stress is due to the vertical overburden stress. As the vertical stress squeezes the rock vertically, it pushes horizontally. The amount of resulting horizontal stress depends largely upon the Poisson's ratio of the rock. For example, rock with higher Poisson's ratio will have higher horizontal stress than will the low Poisson's ratio rock. The following equation demonstrates relationship between horizontal stress and Poisson's ratio:

$$\sigma_h = \left[\frac{\nu}{(1-\nu)}\right](\sigma_v - \alpha P_p) + \alpha P_p \tag{3.3}$$

where σ_h = Horizontal stress, psi

ν = Poisson's ratio

σ_v = Vertical stress

α = Biot's constant

P_p = Pore pressure, psi

Other horizontal (σ_H) stress sources may exist. Tectonically active areas where faulting or mountains are present or where other geologic anomalies, such as salt domes, exist can add to the horizontal stress and cause unequal horizontal stresses to result. The most effective method of obtaining minimum horizontal in situ stress magnitude in drilled holes is from hydraulic fracture testing. However, fracture testing is not routinely performed, and even when performed at casing seats, only a limited set of data points will be available. Consequently, the approach used in this study is calibrate the value of rock stress comparing to obtaining value from Leak off pressure which is mostly performed at the intermediate casing seat.

c) In Situ Stress

Prior to be drilled, formation rocks are in a balanced or nearly balanced stress state with little to no movement occurring in the rock system. The system is said to be "static" or not in motion. The three principal stresses prior to drilling are called in situ stress. In situ stress consists of one vertical stress and two horizontal stresses as shown in the Figure 3.3. The in situ stress includes of overburden and horizontal stresses can be represented in a rectangular coordinate system. The axes of this coordinate system correspond with the direction of the in situ stress.

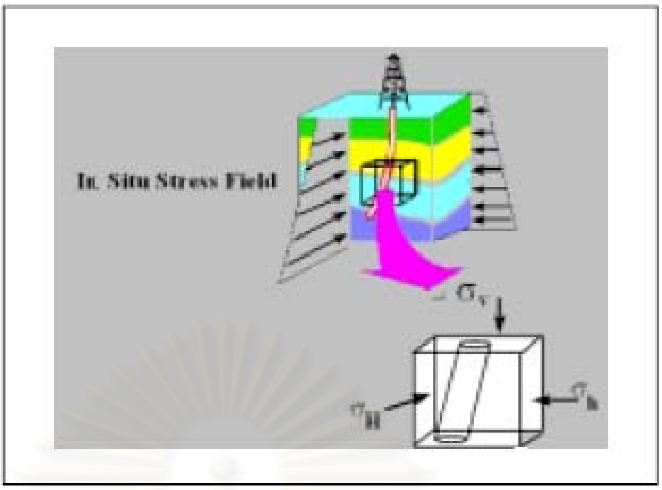

Figure 3.3: In situ stress component diagram.

3.1.3 Stress at The Wellbore

A wellbore drilled into a formation disrupts the stress condition and changes the in situ stress condition near the wellbore. During the drilling process, rock is removed and replaced with drilling fluid. Since the mud pressure does not exactly match the stress previously exerted by the removed rock, an imbalance in the stresses around the wellbore results.

The stresses at any point around the wellbore can be calculated. Near wellbore stresses are calculated from in situ stresses and are a function of overburden stress, horizontal stresses, and angle of the wellbore (the degree of wellbore inclination or deviation from vertical). In situ stresses are first transformed into a rectangular coordinate system in which the z axis is parallel to the wellbore axis.

Then, the near wellbore stresses are calculated and represented in a polar coordinate system. Because the wellbore is circular in shape, a polar coordinate system is used to represent stresses around the wellbore. The force diagrams are shown in the Figure 3.4 and 3.5.

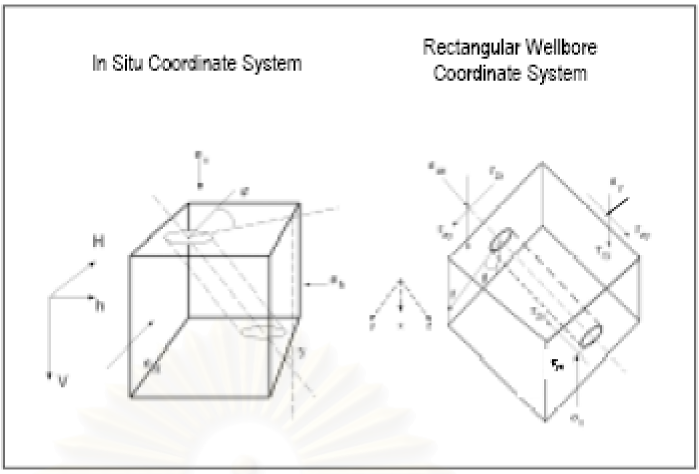

Figure 3.4: In situ stress and coordinate system (RMA NT manual, 2002).

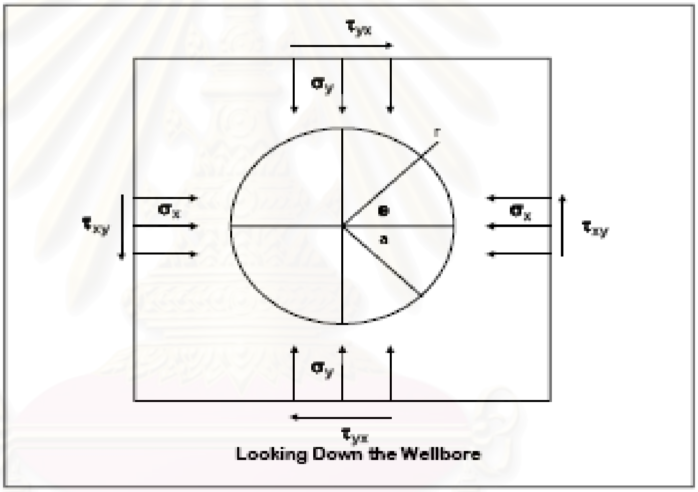

Figure 3.5: Stress at the well bore direction (RMA NT manual, 2002).

Next section introduces rock strength and failure criteria with Mohr-Coulomb theory and model. This model is also used as a geological framework in the RMA model software.

3.2 Rock Strength

Rock strength is an indication of a rock's ability to resist deformation when external stresses are applied to the rock. It is measured as the limiting stress that a rock can withstand without failing by rupture or continuous plastic flow. Rock strength is affected by the confining stress of the rock and the physical properties of the rock. Rock strength is measured in terms of compressive strength and tensile strength. The ability of the rock to resist being compressed or crushed is called compressive strength. The ability to resist stress that would stretch or pull a rock apart is called tensile strength.

Shear Strength is the stress required to cause shearing in a rock. In magnitude, it is the amount of stress required to overcome cohesive strength and frictional resistance to shearing.

The cohesive strength of a rock is the strength of the cementing material holding rock particles together. It is that portion of shear strength attributable to the bonding of rock grains. Also referred to as inherent shear strength or cohesion, it does not depend upon the inter-particle friction. It is the strength required to hold a single sand grain to the rock surface. Since rock grains have a higher density and greater resistance to compression than does the cementing material, the cementing material holding grains together becomes the "weaker" part of the rock matrix. As the cementing material changes, so will the resulting cohesive strength and the overall strength of the rock.

The frictional resistance is the product of the coefficient of friction and the compressive (normal) stress. The coefficient of internal friction is the resistance to movement along a shear plane due to frictional forces. The coefficient of friction is the tangent of the Angle of Internal Friction (F_{ang}). The angle of internal friction is the angle from horizontal of the plane along which shear failure occurs in a destructive test of a core specimen. The angle of internal friction is used as an indicator of rock abrasiveness when performing drilling operation. It is one of the key to adjust appropriate drilling parameters in order to maintain bit life and eliminate cutter worn out problem. Consequently, drilling cost and time saving from multiple trips will be achieved.

3.3 Failure of Rock

Naturally, stresses in balance or failure condition are not a concern. Only when an interruption of the stress balance occurs, for example by drilling a well, is formation failure possible. When rock material is removed from the wellbore, the rock material at or near the wellbore wall must support in situ stresses as well as the stresses that were previously supported by the removed material. Stresses that greater than those of the surrounding in situ stresses are the total stresses result at the wellbore wall.

Rock failure scheme can be explained with Mohr-Coulomb failure theory by studying interactive of core sample when applied by force. According to the model study, normal force (compression) is introduced as a σ_1 in uniaxial stress model and σ_2, σ_3..., σ_n as a confinement pressure in triaxial model as shown in the Figure 3.6.

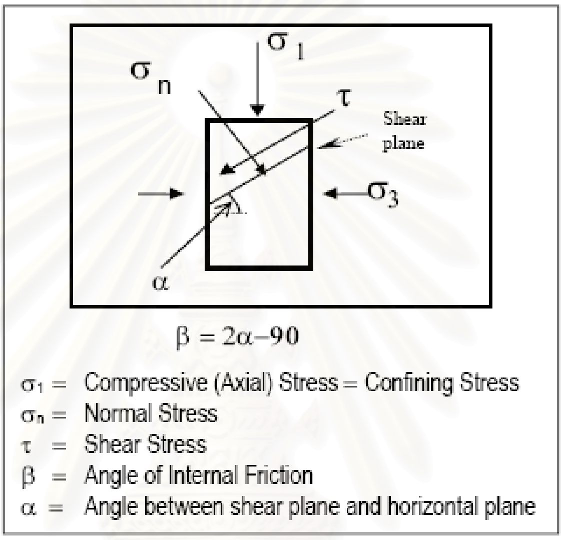

Figure 3.6: Mohr-Coulomb theory model.

A rock will fail when the magnitude of the applied stress exceeds the rock strength. Unconfined Compressive Strength (UCS) indicates the stress magnitude required to fail a rock in the absence of confining pressure, for example, $\sigma_3 = 0$. As confining pressure increases, the rock strength increases. See Figure 3.7 for an illustration of this fact.

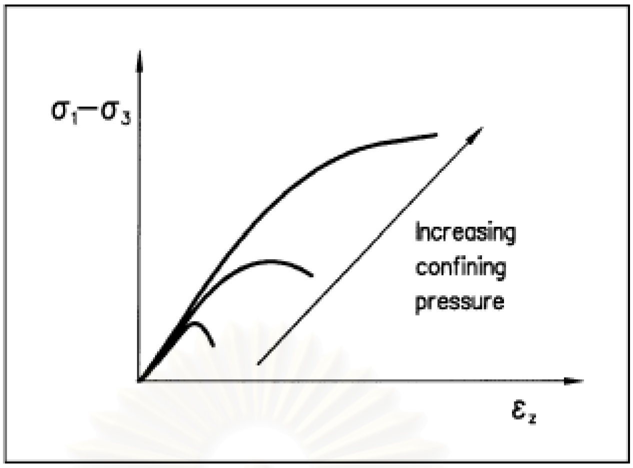

Figure 3.7: Rock strength changes as applied pressure changes.

3.3.1 Mohr-Coulomb Theory

Predicting the potential for formation failure is critical to the petroleum industry especially in drilling. The process of drilling a well can greatly change the in situ stresses and result in disturbing consequences to development drilling or production activities.

Evaluating the potential for formation failure requires knowledge of the in situ stress state including of pore pressure evaluation, and elastic moduli and other rock strength parameters for the formation being evaluated. Key steps to predicting formation failure include of:

a) Determining stresses around the wellbore.

b) Determining formation strength and strength-stress relationships.

c) Comparing formation strength to wellbore stresses relative to specified failure criteria.

3.3.2 Types of Failure

Formations fail in one of two ways which are shear or tension mode. In fact, formations can experience both shear and tensional failure simultaneously.

Shear failure results in response to a formation in compression or normal stress as mentioned earlier.

Compression can occur without failure resulting, depending on the amount of stress asserted by the formation. Failure results when shear stress exceeds the cohesion and frictional resistance of the rock. Within the wellbore, shear failure is associated with excessive hoop stress, and will most commonly be the primary cause of sand production or wellbore instability while well is producing.

Tensile failure occurs in formations experiencing effective tensile stress, which is higher than the rock tensile strength. In most rock the tensile strength, T_o, is usually less than the UCS, indicating that rocks have less resistance to tensile failure than to compressive failure. In the study, tensile strength is estimated as one twelfth of the magnitude of UCS. Existing micro fractures and any discontinuities existing in the rock matrix may affect the tensile strength and contribute to tensile failure.

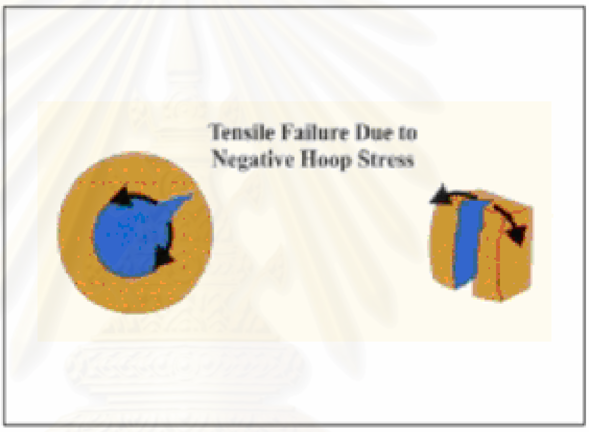

Figure 3.8: Rock failure due to tensile stress.

Tensile failure produces fractures in the case of increased radial stress due to increased drilling mud weight. This is the basic principle of Hydraulic fracturing work. Figure 3.8 illustrates tensile failure at the wellbore wall associated with a negative hoop stress.

3.3.3 Failure Criteria

The prediction of how formation fails or what criteria should be used to specify the conditions that will cause formation failure are the basic aim of rock mechanics study. The failures criteria help provide the answers to these questions. Many criteria exist for predicting rock failure. Those of interest for this study include the maximum tensile stress criterion for indicating failure under tension, and Mohr-Coulomb criteria for predicting shear failure. Rock failure occurs if either of the failure criteria is met.

These failure criteria are based on the stress/strength relationship, describing the interaction of stresses and rock strength to determine the tendency of formation failure. The maximum tensile stress criterion states that a rock will fail in tension if the least principal stress is negative and its value is equal to the uniaxial tensile strength. Tensile failure is always in response to a negative stress. Tensile failure will develop perpendicular to the minimum stress direction. The maximum tensile stress criterion is expressed as:

$$\sigma_3 = -T_o \tag{3.4}$$

where σ_3 = Principal Stress

T_o = Tensile Strength

In this section, the relationship between rock strength and stress will be discussed with Mohr-Coulomb Theory. For shear failure explanation, Mohr-Coulomb failure theory describes failure in terms of maximum effective principal stress (σ_1) and minimum effective principal stress (σ_3). The Mohr-Coulomb theory assumes that failure will occur when the maximum shear stress in a plane exceeds the shear strength of the rock. The shear stress causing failure is resisted by the cohesion of the material and friction.

Multiple Mohr's Circles can be plotted based on repeat core tests on samples. As shown in Figure 3.9, the tests are run with varying magnitudes of confining and axial stresses applied a line is constructed tangent to the plotted circles, forming the Mohr failure envelope.

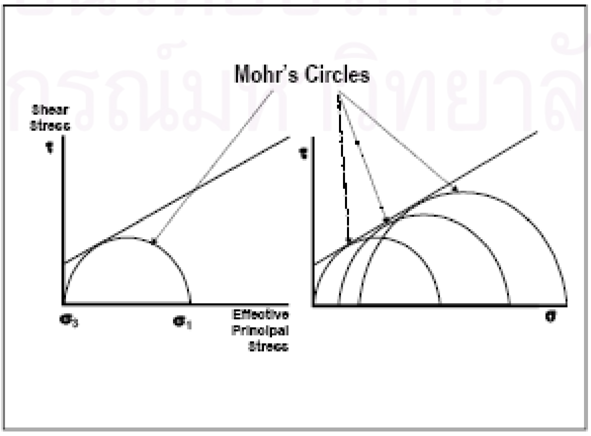

Figure 3.9: Example of Mohr's circle plots.

According to Mohr-Coulomb failure criteria, the point where the failure plane intersects the vertical axis gives the cohesion (S_o) of the rock. The angle formed by the line intersecting the horizontal or principal stress axis gives the angle of internal friction (β) as shown in the Figure 3.10. The slope of Mohr's failure envelope is tan (β), also referred to as the coefficient of internal friction, F_{ang} in the RMA software model.

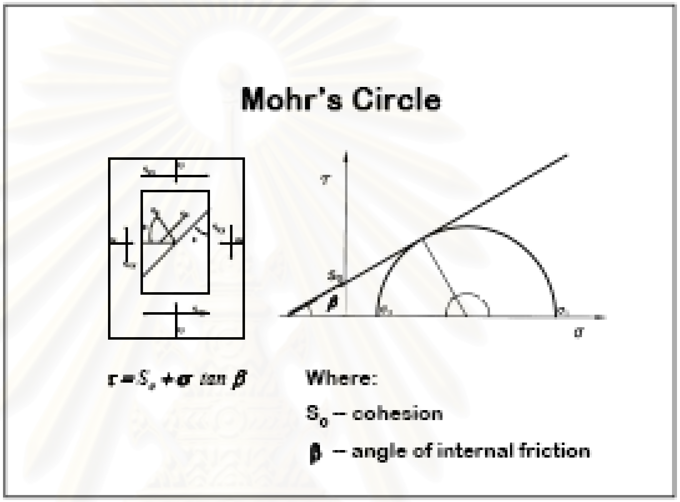

Figure 3.10: Mohr's circle plots with obtain rock properties.

The meaning of rock strength and stability are shown in the Figure 3.11. The stability and instability area are indicated by failure plane boundary. This is helpful for understand formation and stress and strength relation when utilizing RMA to actual field implementation.

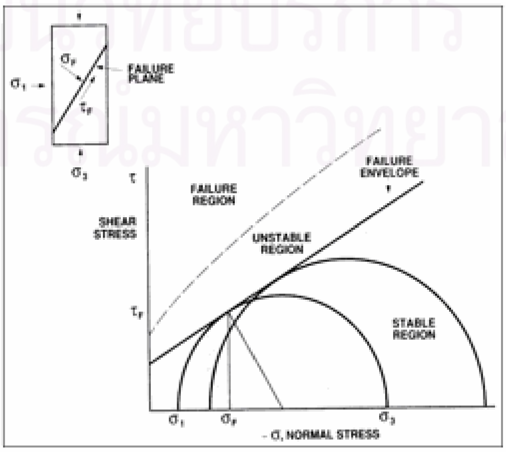

Figure 3.11: Mohr's coulomb plot and Failure prediction.

RMA software model considers magnitude of the surrounding pressure at any point in the wellbore drilling. Mohr-Coulomb theory is brought into this process to determine wellbore stability while drilling. However, in practical field work, rock stresses and properties measurement cannot be executed by core sample study due to rig time limitation. Next section introduces the practical procedure to evaluate rock stresses and properties by the absent of core sample.

3.4 Measurement of Rock Strength and Stresses in Field Works

Presently, practical techniques and tools to directly use for measuring rock strength and in situ stresses include of Core tests, Leak-off Test (LOT), Formation Integrity Test (FIT), and mini-frac test. Core tests provide the only means of directly measuring rock strength and static mechanical properties, and involve laboratory procedures for testing a core sample of rock as available. The Leak off test, Formation integrity test and mini-frac tests are field methods for determining stresses. Only laboratory test procedures are reviewed next.

Prior to performing core tests, visible descriptive information about the core sample is recorded. These data include grain size and grain size distribution, mineral composition, cementing, fracturing, and bedding together with bedding orientation if possible. Acoustic tests may also be conducted. Laboratory measurement of rock strength can be physically achieved through testing of a core sample extracted from the formation. Sample size is generally a length to width ratio of 2:1.

In core testing, a rock sample is placed in a cylindrical, piston-type testing device where a compressional stress can be applied in one or more directions. Tensile strength can also be determined using core testing, but is generally not a concern since tensile strength is very small relative to compressive strength (approximately of one twelfth). Laboratory measurements of strength are made in either the Uniaxial Core Test or the Triaxial Core Test. Other procedures for determining strength include the use of empirical equations and well logging data to calculate strength. Figure 3.12 illustrates the stress to core relationships for each type of core test.

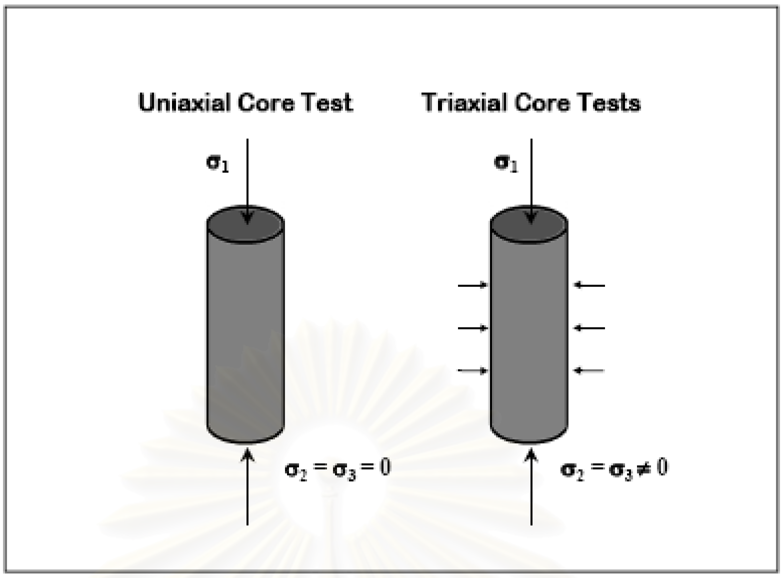

Figure 3.12: Types of core test.

The Uniaxial Core Test is an unconfined test in which a force is applied parallel to the axis of the core sample. No lateral forces are applied and therefore the sample is unconfined. The magnitude of applied stress is increased until sample failure is reached. The stress at failure is the Unconfined Compressive Strength (UCS), which is a measure of a rock's strength expressed as the amount of stress a rock can withstand when unconfined laterally without failing. This test also yields data for Young's modulus and Poisson's ratio.

The Triaxial Core Test is a confined test that measures strength at different levels of confining pressure. This method can represent the nature of formation being drilled. Axial and confining pressures are applied to the sample, increasing each simultaneously until the desired test pressure is reached. The confining pressure is then held constant while the axial pressure is increased until failure of the sample occurs. This test yields Confined Compressive Strength (CCS). Multiple confined core tests are used to determine cohesion and angle of internal friction. It is also used to measure elastoplastic stress-strain behavior.

Practically, it is not widely taking core sample from development well drilling because of the economic reason. On the other hand, for a certain area of this study, rock strength and properties interpretation usually refer to exploration drilling data in the proximity area which has core drilling program or Full-set of lithology logging program. In next section, the correlation for interpretation is presented because this is the fundamental data acquire to optimize further drilling parameters by the absent of core sample and laboratory test.

3.4.1 Building RMA Geological Model

The aim of the Rock Mechanics Algorithm (RMA) study is to support well planning, drilling, completion, and production operations. The program determines rock properties and models that influences in these applications. Using the RMA program to assist with well planning has resulted in enabling more quality and timely simulation studies. The RMA workflow concept is shown in the Figure 3.13.

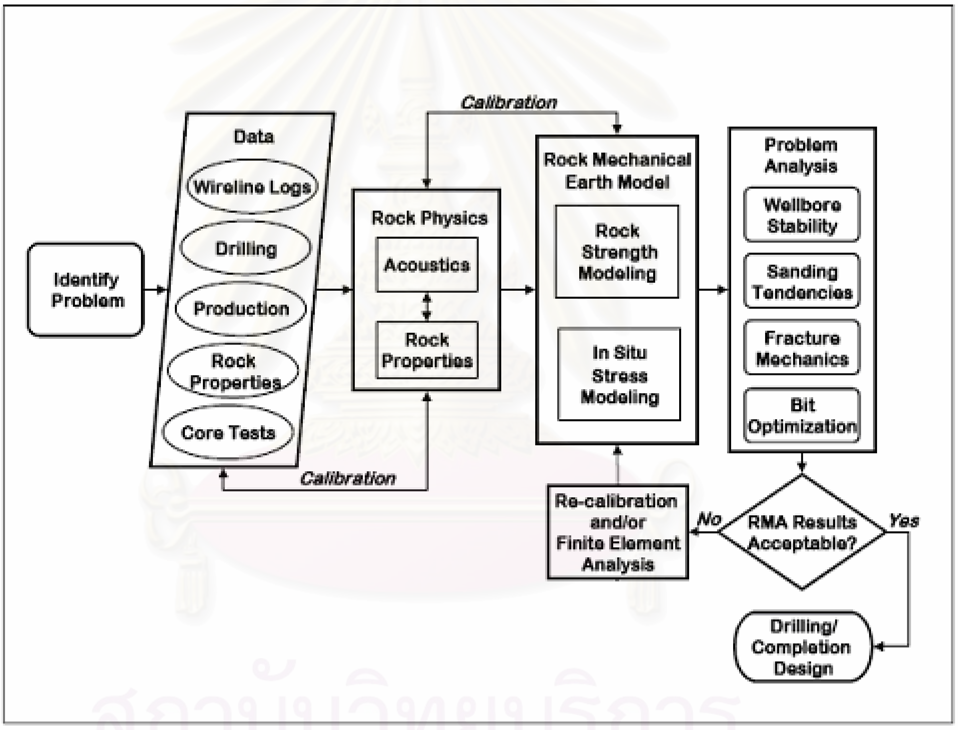

Figure 3.13: RMA program workflow (RMA NT manual, 2002).

RMA software program workflow can be explained step by step of works as the following:

a) Problem Identification

In this study, the goal of Optimization Bit and Drilling parameters are the identified problem.

b) Data

The basic requirement for input in RMA software is Gamma Ray and Sonic Log from open hole wireline process. The supplement data from Drilling, Production, and History loggings are very useful. This study input Lithology information, Drilling records, Pore pressure, Directional surveys, Mud weight, and Bit records as a model construction data and presentation format. The RMA logging analysis workflow is shown in the Figure 3.14.

c) Rock Physics

Rock physics is derived from previous available logging data. Wireline logs provide very important data inputs to the program. The minimum wireline log data inputs to begin execution are Compressional Travel Time (dt_c) log and a Gamma Ray log or Shale Volume (V_{shale}) data. RMA analysis is enhanced by also using other open hole log data such as rock density and porosity into the calculation processes.

d) Rock Mechanics Earth Model

Model is estimated by gathering all data as mentioned earlier. Then, the program also generates database and model for further using.

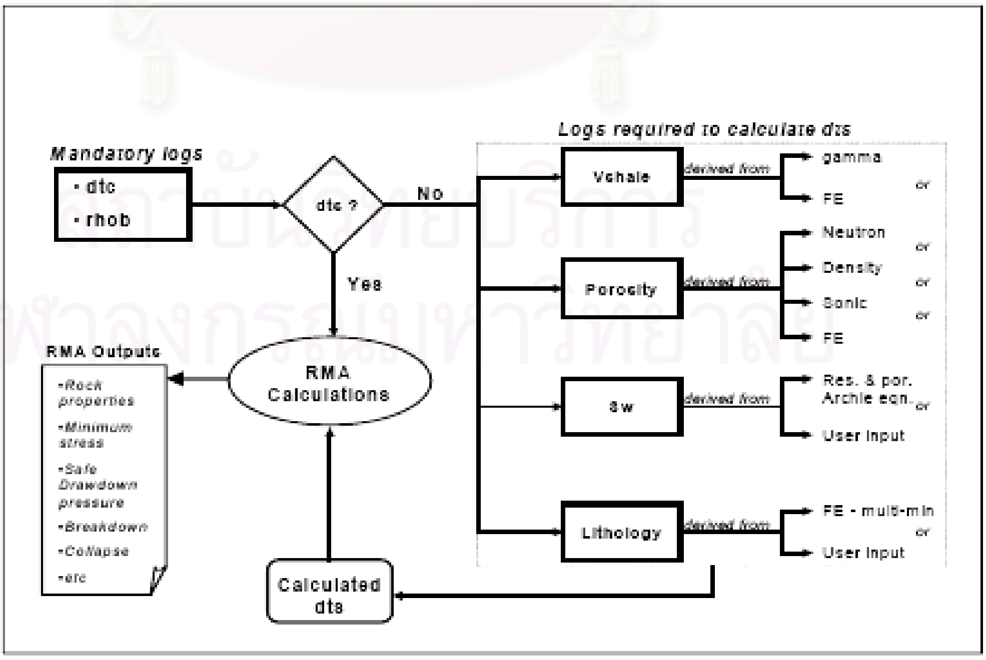

Figure 3.14: Logging data analysis workflow (RMA NT manual, 2002).

e) Calibration

This process needs historical data to calibrate the model. It will occur many times during the study until reach matching model.

3.4.2 Estimate Rock Strength and Properties from Correlations

Due to the absent of actual core lab measurement, the study utilizes the correlations to calculate preliminary data as follow:

a) Unconfined Compressive Strength (UCS)

According to logging data and formation lithology, UCS can be determined from these values with an evaluation from Formation Evaluation Specialist (FES). UCS is a function of Shear wave velocity which can be measured or calculated. For this study, UCS is estimated from the following equation together with wireline data:

$$UCS = AV_S^2 + BV_S + C \tag{3.5}$$

where UCS = Unconfined Compressive Strength, psi

V_S = Shear wave velocity, fps

A, B, C = constant (proprietary)

The Unconfined Compressive Strength (UCS) is the most commonly utilized mechanical property for bit selection and performance prediction. UCS denotes the maximum compressive load a material can withstand before failure. UCS can be determined experimentally by measuring the stress necessary to fail the material under a compressive load without the presence of any other confining pressures (uniaxial testing). UCS does not inherently increase with depth since its measurement assumes an absence of confining pressures.

Several mechanical properties utilize the logged compressional sonic values and material constants for the relevant lithology to estimate the UCS value. Additional log data can be utilized if it is available, including shear sonic, porosity, and/or density. If log data is not available for these parameters, they are calculated. One of several UCS algorithms is used based on an internal logic that selects the most appropriate method. This system of equations and selection logic ensure that estimator can arrive at the best possible estimation of UCS available in the industry today.

UCS values are commonly used in the drill bit industry to assist in bit selection and estimates of anticipated bit performance. It is difficult to establish precise bit selection rules using UCS due to variances of other parameters such as lithology type, compressibility, fracture toughness, and confining pressures. However, local guidelines can usually be built around experience utilizing the tool. The UCS values are used to help derive many of the other values listed in this section.

There are several limitations associated with the UCS value calculated by software. First and foremost, the only way to actually measure UCS is to perform a uniaxial compression test on a core sample of the material itself. The UCS values developed through the interpretation of log data are estimates only. If the lithology description developed by the user through interpretation of the gamma ray log is inaccurate, the UCS will be inaccurate as well. UCS calculations use several material constants that depend greatly on the defined lithology. Lastly, always remember that UCS is the unconfined compressive strength value. Rock formations are always under some amount of confinement pressure.

b) Overburden Stress

For this study, Overburden Stress calculation uses correlation 3.2 as described in the section 3.1.2. The value is calculated and put into vertical stress estimation. Directional well path also affects the magnitude of overburden stress calculation.

c) Horizontal Stresses

Horizontal Stresses are accounted for Poisson's Ratio effect of the rock as shown in equation 3.3.

3.5 Well-site Geological Data Requirements

In order to construct RMA program, the fundamental data requirements are comprised of:

a) Wireline Loggings

Wireline log quality is extremely important in generating rock stress model. This process is closely monitored and evaluated by Formation Evaluation Specialist (FES) team who construct and validate RMA geological model. Wireline logging data are composed of:

1) Sonic Logs

Sonic Logs provide Compressional travel time (dt_c) but Shear travel time (dt_s) can be calculated from dt_c and lithological properties. However, if measured dt_s is available, it will increase accuracy of the calculations.

2) Density Log, ρ_b

Bulk density (ρ_b) can be obtained from Density Log. It is mandatory data to calculate overburden stress or vertical stress. Practically, it is important to obtain density log as shallow as possible.

3) Gamma Ray and V_{shale}

Gamma Ray is used to calculate and construct V_{shale} curve. It is not mandatory value if V_{shale} curve is available from offset well. Gamma Ray is also useful to calibrate V_{shale} sensitivities and identify lithology.

4) Neutron Porosity Log, ϕ

Neutron Log provides Total Porosity (ϕ_t) value. It is not mandatory value if porosity curve from offset well is available. Total Porosity is useful for hydrocarbon identification.

5) Caliper Log

Caliper Log is not use for calculation but use for identify hole problem, identify intervals of questionable open hole log quality, calibrate stresses directions and magnitude from borehole ovality and mud weight.

6) Additional Logs

Some of additional logs are useful for model calibration such as Non-shale lithology trace, Spontaneous Potential, and Borehole image log.

b) Mandatory Input Data

1) Pore pressure

Pore pressure can be simulated from offset well, production data, RFT and MDT data.

2) Lithology legend

Lithology legend can be obtained from mud logs data or log analysis from previous and offset well in the proximity area.

3) Hole inclination

Inclination of the wellbore can be acquired from measuring while drilling recorded and directional survey data.

In the next section, drilling operation and planning is briefly reviewed and discussed. Cost per Foot (CPF) concept which is normally used as a criterion to evaluate drilling performance and decision making tool is also presented.

3.6 Drilling Performance and Optimization

Drilling personnel know that improving drilling economics means getting drilled well deeper with the cheaper expenditure. It has been entrusted with the expenditure of millions of dollars. This trust obligates us to be cautious and intelligent in our actions and to actively seek out ways of reducing project expenditures without compromising project quality. The goal objective is to drill the best quality well as inexpensively as possible. The concept of cost per foot was developed to gauge the economic success in this effort and to use as a decision making tool. Cost per Foot (CPF) remains the standard of drilling performance.

3.6.1 Drilling Performance

One method to achieve the lowest cost per foot is to optimize various drilling parameters. As drilling parameters are optimized, drilling cost per foot should decrease. Cost per foot is a useful tool both for analyzing real-time rig performance and for predicting future performance. Cost per foot is a factor in almost every drilling decision and when conditions permit, it is usually the deciding factor.

Cost per foot is not the total cost of the well divided by its total depth. Such a number includes the cost of tangibles such as casing and wellheads which have nothing to do with drilling performance. Instead, cost per foot is determined by numbers which relate directly to the decisions we make on the rig and their associated costs. Cost per foot is defined as follow:

$$CPF = \frac{B + R(T_r + t)}{F_t} \tag{3.6}$$

where CPF = Cost per Foot, \$/ft

B = Bit Cost, \$

R = Rig Operating Cost, \$/hr

T_r = Rotating Time, hr

t = Trip Time, hr

F_t = Footage Drilled, ft

The bit cost (B) is the net cost of the drilling bit. This is particularly important when dealing with diamond bits. In these cases, the bit cost is the original cost less its salvage value. For a rock bit, there is generally no salvage value, so the bit cost used in the equation is the original bit cost. The rig operating cost (R) is a very important factor in the cost per foot equation. This represents the actual hourly cost while conducting the drilling operation which is comprised of Drilling rig contract day rate, Rig site supervisor cost, Daily materials and services bills, and Daily rental costs.

In general, all daily intangible well costs are incorporated into the total rig operating cost. Items such as casing, wellhead equipment, production equipment, etc., are not considered in determining the operating cost because these are tangible costs and are not affected by the drilling performance. On the average, the total operating cost per day is about twice the contract day rate of the drilling rig.

Rotating time (T) is the total number of hours the bit is on bottom drilling. Trip time (t) is the total time associated with getting a new bit on bottom. Trip time should include the time spent while circulating and conditioning the mud, while pulling out of the hole, while changing bottom hole assemblies, while running back in the hole, and any time spent reaming and circulating. Trip time should not include any time spent testing BOP's, inspecting Bottom Hole Assembly (BHA's), running casing calipers, etc.

Footage drilled (F_t) is the total number of feet a particular bit has made while in the hole drilling. This should be only the actual feet of new hole cut by the bit.

This study aims goal in decision making is to determine the least costly option which fully meets drilling objectives. Cost per foot is one instrument used in these determinations. There are two ways of lowering the cost per foot on a well;

a) Lower the daily expenses which are charged to operator.

b) Reduce the time spent on particular operations.

While closely consider of all variables, rotating time (T) and trip time (t) are emphasized on this study. The solution to optimize drilling parameters and maintain bit life can reduce overall drilling cost. The theory of Rock Mechanics and Rock Specific Energy are brought into this study to optimize drilling parameters and to use as an operation guidelines in production hole section because of economic criteria and availability of data in this section.

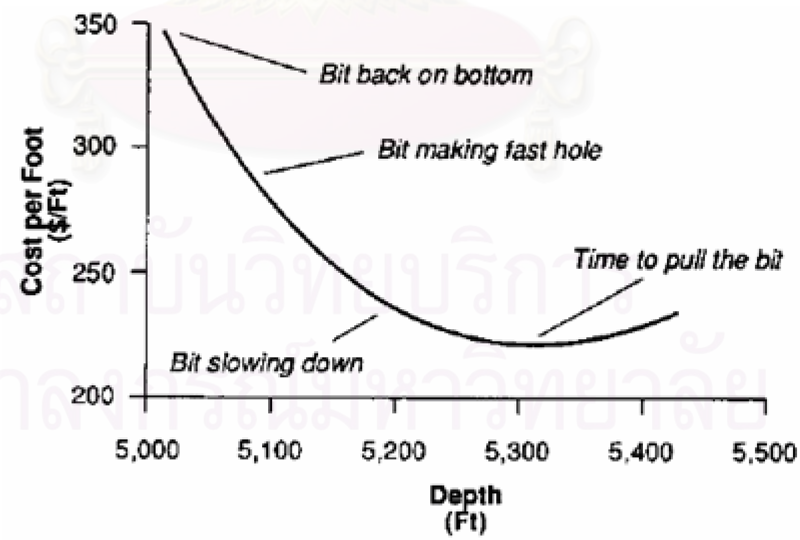

Figure 3.15: Applications of cost per foot plot.

One application of the cost per foot equation is in determining the optimum time to pull a worn bit. When all the tripping costs are figured in, the cost to drill the first foot of hole after a new bit is put on bottom is very high. But as the bit run progresses and the tripping cost is divided over many feet the average cost per foot decreases. However, as drilling proceeds, the bit dulls and the penetration rate begins to drop. Finally, the bit is drilling so slowly that the average cost per foot of the bit run starts to increase. Figure 3.15 shows the typical reduction in cost per foot as the bit run progresses, reaching a minimum at some point and continued drilling increases the cost per foot for the bit run.

When the cost per foot equation hits a minimum point, continued drilling becomes uneconomical and the bit should be pulled. This is not to say that the bit would be unable to drill ahead for many feet after the cost per foot minimum is reached. It simply means that the costs associated with staying on bottom and drilling ahead are higher than tripping out of the hole and picking up a new bit which will drill faster.

There is a simple tabular method of keeping track of the cost per foot during a bit run in the field. It involves calculating a Critical Penetration Rate (P_c) from the cost per foot data. P_c is calculated as the penetration rate which must be achieved in the next interval of hole in order to keep the cost per foot from increasing during that interval. When the actual penetration rate drops below P_c, then the cost per foot for that bit run has started rising, and the bit should be pulled. The critical penetration rate can be determined by dividing the hourly rig cost by the cost per foot for the current bit run. An equation of P_c is presented below:

$$P_c = \frac{R}{CPF} \tag{3.7}$$

At times, using the critical penetration rate method of bit pulling can have its drawbacks and limitations. Rapid sand-shale sequences can cause wide variations in penetration rate which confuse the issue. A worn bit can still drill easily through sand sections but slows down through shale sections may be difficult to analyze using P_c. In these cases, knowledge of the formations to be penetrated can be extremely useful in determining when to pull the bit.

In another example, a worn bit which is struggling to drill through sand-shale sequences may be left in the hole longer than P_c would indicate. Faster penetration rate can be expected or it may be acceptable to extend a bit passes the minimum cost per foot if distance is very close to TD or a casing point and bit still has some life in it.

In these situations, it would be very expensive to trip for a new bit just to make a few feet of hole. On the other hand, stretching a bit to TD or casing point should not be attempted unless we are confident that the bit has sufficient bit life to get to hole TD.

As mentioned earlier, when drilling in high compressive stress formation, drilling ROP is normally slow down. Thus, CPF analysis plot should indicate tendency of increasing in cost per foot while drilling and resulting in tripping for new bit. However, in some cases after encounter 100’-200’of slow down ROP, increasing in ROP is observed until reach TD and bit coming out of hole still in the good condition. RMA model will help in making decision with CPF analysis. This will eliminate tripping time and new bit cost from inappropriate decision making.

3.6.2 Drilling Parameters

The aim of this study is to optimize drilling parameters to achieve maximum drilling penetration rate while maintain bit life. This section introduces important of drilling parameters and each their relationship.

a) Weight on Bit (WOB)

Generally, operator would like to drill as fast as possible except that sometimes the consequences of running high bit weights may be intolerable and shorten bit life. This problem leads to pull the bit out of hole resulting in additional bit cost and trip time. High bit weights may cause early bearing failure in the roller cone drill bit.

All bit manufacturers publish recommended bit weights per inch of bit diameter. Following these recommendations will help prevent premature bearing failure.

If the higher bit weights lead to increased ROP, the amount of cuttings in the annulus will also increase. Then, the increased mud weight on the back side can cause lost circulation problem, surface solid control handling problem, and required more hydraulic transmit system.

The operator must give-and-take while trying to balance increased penetration rate against these and many other bit weight induced problems.

b) Rotary Speed (RPM)

Practically, ROP should increase as rotary speed increases. Faster rotary speeds have the effect of causing more tooth-formation contacts per second which should increase the amount of formation drilled per time interval. However, experience has shown that there are both practical and behavioral limits to this effect. At lower rotary speeds (50-100 RPM) and particularly in softer formations, the penetration rate is frequently linear in response to changes in the rotary speed. However, empirical data shows that the relative response of ROP to an increase in rotary speed begins to diminish at some point in almost all formations.

At very high rotary speeds (in excess of 160 RPM), incremental increases in ROP are often counteracted by significant reductions in bit tooth and bearing life. It is often generally assumed that bit weight wears out teeth and rotary speed wears out bearings.

Some rotary table manufacturers publish data recommending a maximum table speed of 500 RPM. While this speed may be mechanically feasible, things on the rig floor really start deteriorating rapidly at much over 200 RPM. Safety and equipment concerns place natural limits on the maximum rotary speed which is realistically maintained.

The chance of injury is increased if something breaks loose at high rotary speeds due to impact action while drilling as shown in the Figure 3.16 for an example. Mud motors can rotate a bit at over 350 RPM but this does not always produce a higher penetration rate over what can be obtained by rotating the string conventionally at the surface. Some hard formations do not respond to increases in rotary speed, as the penetration rate through them is primarily a function of bit weight.

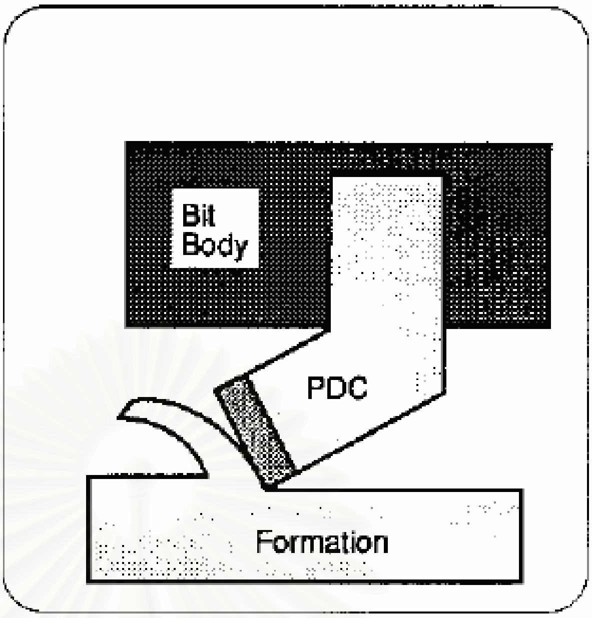

Figure 3.16: PDC bit cutting action.

There may also be high speed problems associated with drill string resonance created at or near a critical rotary speed. Critical rotary speeds produce harmonic resonances in the drillpipe which cause it to vibrate wildly. The extent of the vibrations can vary from an uncontrollable shaking to early fatigue failures in the tooljoints.

3.6.3 Optimizing Drilling Parameters

The method is widely used to optimize drilling parameters is Drill-Off Test (DOT) because there is no single combination of bit weight and rotary speed which drills optimally through all formations. DOT represents the relationship between WOB and RPM while drilling at any tested point. Because some formations are much more responsive to changes in rotary speed than bit weight, and vice versa. In order to optimize our penetration rate, DOT always conducted before start drilling in a certain section.

A single DOT can only determine the bit weight necessary to optimize the penetration rate for a single rotary speed. Additional drill-off tests need to be run at different rotary speeds to determine the optimum rotary speed/bit weight combination. If no bit floundering was observed in the initial DOT, then additional bit weight or higher rotary speeds are acceptable for subsequent tests. If bit floundering was observed on the initial DOT, then slower rotary speeds should be examined.

DOT provides combination of WOB and RPM in terms of ROP result. We can use this guideline to adjust drilling parameters while drilling through different zone of formations. Unfortunately, in some drilling area does not conduct DOT anymore due to rig time consumption and cost.

For this study, RMA software is used as a simulator for optimizing drilling parameters based on Specific Energy concept. Geological data and lithology identification are constructed in the model by formation evaluation specialist then WOB and RPM are optimized based on ROP specific energy and bit life concepts.

3.7 Drilling Bit Feature and Designing

The drilling bit is one of the most important tools on the rig. It is operating many of feet below the surface under high pressure, high temperature, and high impact conditions. Drilling bit duty is the destruction of rock millions of years old. While continuously pump thousands of gallons of mud through it, thousands of pounds of weight has also been applied to it and simultaneously spinning it at any rotary speed. So, if it doesn't perform properly, a multi-million dollar drilling rig is wasted for tripping and changing BHA’s.

Bit performance optimization addresses two issues. First, a bit must be selected for the upcoming bit run which will stay in the hole a long time and give good overall penetration rates. Second, the bit must be operated properly while on bottom and while running so that we do not reduce its drilling potential.

As per usual, the basis for selection of a particular drilling bit is cost per foot. We want to select the bit which will provide the lowest cost per foot over the upcoming interval. This decision will involve an investigation into a variety of wellbore factors including formation hardness and hole angle. In addition, there are design aspects to all drilling bits such as offset and journal angle, which make them better performs in specific environments. Bit design is at the heart of proper bit selection. The operator must know what qualities in a bit will be required to drill the next section of hole in the most economical way possible.

3.7.1 Formation Characteristic

Drilling bit designing always deals with different formation being drilled. This section provides different formation characteristics that are categorized into three groups based on formation compressive strength.

a) Soft Formations

Soft formations are composed of materials having low compressive strengths (less than 5000 psi). Typical soft formation materials are clay, shale, loosely cemented sand, chalk, and soft limestone. In soft formations, the biggest concerns with milled teeth are bit balling and abrasive wear. A bit is said to be "balled" when sticky formation is packed so tightly in between the teeth that it holds the teeth away from the face of the formation.

Tooth wear is a problem because soft formation bits are designed to drill with a gouging and scraping action, which is inherently abrasive. Bit designers minimize this problem by adding tungsten carbide hard-facing to the teeth. The teeth are as long as possible for maximum penetration into the formation to generate the largest cuttings. When tungsten carbide insert teeth are used, abrasion is not a concern due to the exceptional wear resistance of the material.

b) Medium Hard Formation

Medium Hard Formations are composed of material having moderate compressive strengths between 5,000 and 10,000 psi. Typical medium hard formations include limestone and sandstone. In medium hard formations, the bit relies on a combination of chipping and twisting action to make hole. Milled tooth breakage becomes a problem because higher drilling weights are required so the teeth are shorter and less pointed. Hard facing is still applied to the inner rows of teeth to make the bit more flexible under a variety of conditions.

c) Hard Formation

Hard Formations are composed of material having high compression strengths (greater than 10,000 psi). Typical hard formations include dolomite, hard limestone, granite, and chert. In hard formation, the rock destruction mechanism is primarily by crushing. The milled teeth impact directly on the formation face and grind it. With high drilling weights, the bending forces on a tooth can be severe so the teeth are designed short in order to minimize breakage.

The area of this study is selected in the Medium Hard Formation area and most of the drilling bits using in the area are Polycrystalline Diamond Compact (PDC) Bit. Next section presents PDC bit designing criteria and dull grading method to evaluate drilling bit performance.

3.7.2 Polycrystalline Diamond Compact (PDC) Bit Features

The PDC bit is a one-piece cutting tool using numerous polycrystalline diamond compacts to cut the rock. The polycrystalline diamond cutters consist of a thin layer of synthetic diamonds adhered to a tungsten carbide disc as shown in figure 3.17.

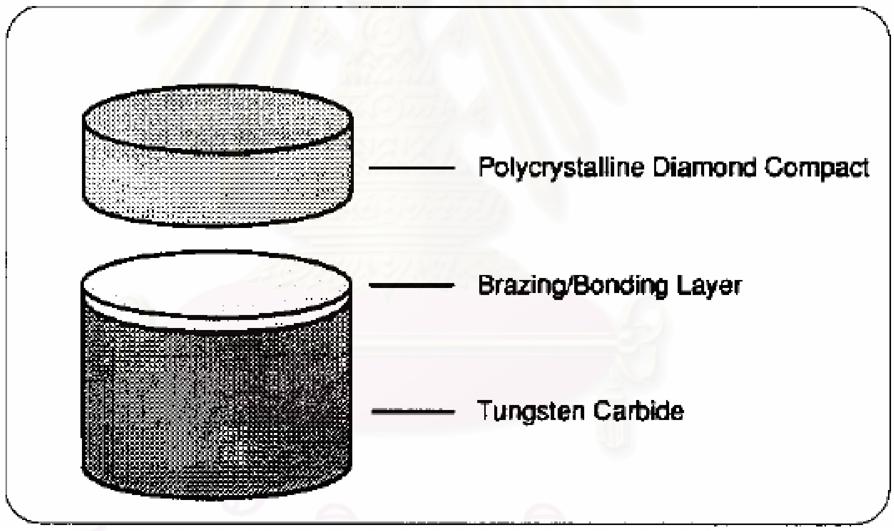

Figure 3.17: PDC cutter construction.

These compacts are produced as an integral uniform under a high pressure, high temperature process. The diamond layer consists of many tiny diamond crystals which are bonded together with their cleavage planes randomly oriented to each other so that shock impacted breakage in an individual diamond crystal does not propagate through the entire cutter. The result is a thin diamond layer with the hardness and abrasion resistance of a diamond, and the impact resistance of tungsten carbide. These bits are a high technology reinforcement of the first type of rotary drilling bit called the drag bit.

PDC bits drill by shearing the rock rather than crushing it as rock bits do or grinding it as natural diamond bits do (see Figure 3.16). Rock fails with significantly less energy in shear than in compression, thus a more efficient drilling action can be obtained with less WOB and variable RPM. In the appropriate formations, PDC bits can drill long and hard. They routinely double the time in the hole and triple the footage of conventional roller cone bits. Conversely, running a PDC bit in the wrong formation will quickly destroy it due to the less impaction resistance comparing to roller cone bit.

PDC bits are expensive and brittle. They can be destroyed by hard formations or weaken by soft gumbo type formations. Thus, PDC bits should be put in the hole only after a detailed analysis of formation lithology has been performed and a compatible formation with sufficient thickness has been predicted to make a PDC bit run economical. The technology of PDC bits is evolving and developing rapidly. As a result, there are many bit designs available from a variety of vendors all trying to prove their product's superiority. A detailed field analysis of these designs has yet to be completed, leaving it difficult to determine the best designs. In many instances, bit that has good performance in a certain areas will not effective in other areas.

3.7.3 PDC Bit Selection and Application

The PDC bit is best matched to drill soft to medium sedimentary formations. PDC bits are widely used to drill formation in The Gulf of Thailand because it drills with a shearing action instead of impaction. It is the most effective when drilling formations that fail easily in shear. Some of the most compatible formations for drilling with PDC bits are clays and shales. Good PDC bit runs have also been obtained through evaporate formations such as gypsum, anhydrite and rock salt. While sandstone does not fail in shear, good runs have been reported in soft sandstones that are not well cemented or too abrasive. The PDC bit is not a good choice to use in hard formations. The brittle PDC cutters can be easily destroyed by hard formations such as chert, granite, calcite, and hard dolomite. In addition, well cemented sedimentary sandstones should not be drilled with PDC bits because of their abrasive nature.

3.8 Relationship between Formation Strengths and Drilling Parameters, Bit Selections and Optimizations

In this section, the specific energy concept is presented together with drilling and bit optimization applications. The correlations and equations which are used in this study are also introduced in this section but the results and discussions will be provided in the next chapter.

3.8.1 Confined Compressive Strength (CCS)

The Confined Compressive Strength (CCS) is the compressive strength of the formation under overburden confinement. The compressive strength of any material is altered by various external pressures that are applied to it. For rock formations, one of the primary external pressures is that of overburden stress. As mentioned earlier in this chapter, overburden stress is essentially the weight of all the formation above a particular piece of rock bearing down on that rock. This overburden weight acts to confine the formation and increase its compressive strength.

CCS values can be estimated based on standard Mohr relationships. Three values must be known to compute CCS in this way – the UCS, the angle of internal friction (Friction angle or F_{ang}), and the confinement pressure. UCS calculations are noted in previous section. Fang calculations utilize a relationship with porosity and clay fraction. Confinement pressure is determined based on the average weight of the formation above and the depth.

CCS is extremely helpful for both bit selection and performance prediction. Rocks with the exact same mechanical properties will usually get more difficult to drill with depth due to confining pressures that act upon them. The CCS values give an indication of this trend while the UCS will not. Most local rules about both bit selection and performance prediction should utilize the CCS numbers. For instance, sustained values of CCS over 45,000 psi are generally not considered PDC drillable.

It has to be noted that CCS value in this study is not referred to the in-situ condition magnitude. The model calculates CCS value based on the downhole condition while drilling with available data in the calculation process. Despite the significant use of CCS, there are several limitations. First, understanding the downhole pressure environment is much more complicated than simply the stress provided by the overburden. Even with a piece of undisturbed rock, there are additional pressures present; including localized structural stresses, formation fluid pressures (pore pressure) and tectonic stresses. Once a hole is drilled into the rock, the situation becomes even more complex. Localized stresses resulting from the borehole exist and overbalance pressures (the difference between the annular pressure and the pore pressure) are very important. In some situations, particularly when drilling is close to balanced or even underbalanced, the UCS may provide a better correlation to the actual drilling performance. Also, it should be noted that using any type of compressive strength as the sole indicator of bit selection and drilling performance can result in poor choices. For example, in some brittle formations (such as some types of limestone), drilling performance is enhanced for a given CCS value due to fracture propagation and localized pre-fracturing of the formation that reduces its effective strength. Finally, the CCS values are based on other estimated values. Items noted above in the discussion of UCS, such as proper lithology identification, are also important for accurate CCS calculations.

3.8.2 Formation Abrasivity

Abrasivity is a new index developed to indicate the abrasiveness of the formation. This is not yet a quantitative value, but rather a relative one. The higher the abrasivity, the more potential the formation has to cause abrasive wear to the bit at downhole resulting in shorten bit life.

Abrasivity is based on a non-linear relationship that includes the angle of internal friction (F_{ang}) and the compressive strength of the formation. The F_{ang} can be utilized as an indicator of abrasiveness because higher F_{ang} numbers indicate a greater amount of “inter-locking” of the formation grain structure. This inter-locking in turn indicates greater grain angularity, which results in abrasiveness. The compressive strength also plays a role in increasing abrasiveness by holding the individual grains in place longer to provide sliding resistance.

Abrasivity is looked as a relative measure that indicates areas of potentially high wear. Abrasivity is usually shown on a logarithmic scale with a “nominal” value of 10 in the center of the graph. Values of abrasivity above 100 should be considered highly abrasive and the user should potentially adjust recommendations of bits and/or operating parameters. These adjustments could take the form of either utilizing a heavier set bit, implementation of more abrasion resistant cutters or inserts, or lowering the suggested RPM in that section.

Rock Mechanic Algorithm (RMA) software offers new methodology which is different from existing ROP prediction methods that are based on UCS. The fact is that UCS does not represent the apparent strength of the formation and will finally tend to generate error results. On the other hand, CCS approach better represents the apparent rock strength to the bit. Using CCS has opened the door to being able to predict more accurate ROP with little or no calibration. For this study, three geological parameters which are effect to drilling bit performance will be considered while optimizing drilling parameters- the UCS, CCS and F_{ang}.

3.8.3 Formation Specific Energy (E_S) and Bit Sliding Coefficient (μ)

Formation Specific Energy (Es) provides a way to estimate amount of energy required and bit efficiency to destroy the rock formation. Es parameter is also powerful to calculate the power requirements (Torque) for a particular bit type at a certain rate of penetration (ROP) and in a given rock type.

In a certain area, if rock strength and bit efficiency are known, predicting the drilling ROP based on work and power that are input to the bit which are weight on bit (WOB), torque and rotary speed (RPM). Torque is actually a reaction of WOB, RPM, rock strength, and bit type. Bottom hole assembly and Well profile are also the torque influences. For this study, we represent the influence of bit type and torque by parameters of sliding friction and efficiency.

Specific Energy theory was proposed for years. For the rotary drilling, Teale proposes the specific energy equation and specific energy balance concept as following:

$$E_S = \frac{WOB}{A_B} + \frac{120\pi NT}{A_B ROP} \tag{3.8}$$

where E_S = specific energy, psi

WOB = weight on bit, lbf

A_B = bore hole area, in^2

N = rotary speed, rev/min

T = bit torque, ft-lbf

ROP = penetration rate, ft/hr

and,

$$E_S = E_{S_{\min}} = \sigma \tag{3.9}$$

$$EFF_M\,(\%) = \frac{E_{S_{\min}}}{E_S} * 100 \tag{3.10}$$

where E_{Smin} = minimum specific energy, psi

σ = rock compressive strength, psi

EFF_M = mechanical efficiency, %

On the other hand, we can reach the optimum efficiency when we apply the specific energy to minimum energy requirement or equal to the compressive strength of the rock being drilled.

In practical field work, most of drilling parameters are measured in the form of surface measurements. So, bit sliding coefficient (μ) is introduced to express the relation between torque and WOB to compute the input specific energy (Es) instead as the following equations (3.11) and (3.12) which have been derived from circular shaft bit:

$$T = \mu \frac{D_B WOB}{36} \tag{3.11}$$

$$\mu = 36 \frac{T}{D_B WOB} \tag{3.12}$$

Substituting equation (3.12) into equation (3.8) and express final equation in term of ROP as the following equation:

$$ROP = \frac{13.3\mu N}{D_B\left(\frac{E_S}{WOB} - \frac{1}{A_B}\right)} \tag{3.13}$$

from equation (3.9) and (3.10) then

$$ROP_{SE} = \frac{13.3\mu N}{D_B\left(\frac{CCS}{EFF_M WOB} - \frac{1}{A_B}\right)} \tag{3.14}$$

where D_B is the bit diameter, in.

3.8.4 The Specific Energy Rate of Penetration (SEROP)

The Specific Energy Rate of Penetration (SEROP) is a calculation based on all above equations that related the drilling specific energy to the compressive strength of the formation. The SEROP is therefore a ‘potential’ ROP rather than a predictive ROP.

By utilizes a proposed equation for specific energy that takes into consideration of the WOB, RPM, ROP, and hole size. This study then applies the industry accepted idea that at maximum drilling efficiency point, the specific energy is equal to the compressive strength of the formation being drilled. The equation is rearranged to solve for ROP and bit efficiency constant is added to adjust the calculation depending on the bit type selected. As mentioned above, the SEROP is an indication of ROP potential only and should not be used to accurately predict the actual drilling ROP. However, the SEROP will usually be proportional to the actual ROP’s and can be used to compare different bit running scenarios. This capability allows us to look at the cost and performance variances for combinations of bits rather than selecting bits on an individual basis. The SEROP can also be used at the rig site to monitor expected variances in the ROP.

There are several important limitations associated with SEROP. First, it only indicates the potential ROP and is not expected to accurately predict the actual ROP. Future derivations of the software will allow for a much more exact input based on individual bit designs. There are numerous aspects of the drilling process that SEROP does not consider, including mud type, downhole dynamics, torque and drag, hydraulic cleaning efficiency, overbalance, and other aspects of the formation besides the CCS. If downhole WOB values can be measured or estimated, they should be utilized with more accuracy.

3.8.5 ROP Efficiency

The ROP Efficiency is calculated for the offset well only and is a simple ratio of the actual ROP and the SEROP. The ROP Efficiency is a simple ratio of the actual ROP divided by the SEROP.

$$ROP_{EFF} = \frac{ROP_{Actual}}{ROP_{SE}} * 100 \qquad (3.15)$$

The ROP Efficiency or ROP ratio provides some useful insight into how efficiently any given portion of the well has been drilled. This is sometimes useful in determining which areas of the well provide the best potential for drilling optimization. The ROP Efficiency is usually displayed on a simple graph ranging from zero to two, one being the value when the actual ROP and SEROP are equal. There are numerous reasons for changes in the ROP Efficiency, including changing of bit types, mud types, lithology, or several other more subtle factors such as variations in pore pressure. However, we can spot areas where drilling is particularly inefficient and try to discover where these inefficiencies may come from. For instance, ROP Efficiency are able to show where the drilling efficiencies dropped significantly whenever the bit entered shale formations and are able to then offer solutions such as more hydraulically efficient bit designs or modified hydraulic parameters in these sections.

Probably the biggest limitation to use of the ROP Efficiency is the numerous aspects of the drilling process that can affect these numbers. It is sometimes difficult to know why the efficiency is changing. Experience and local knowledge is extremely helpful in these instances. Also note that these numbers are built on a series of calculations that contribute to inaccuracies (ROP Efficiency is built on the SEROP that is built on the CCS that is built on several quantities that are built on the logged sonic values). It may also note that there is some correlation between the ROP Efficiency and the formation types being drilled. For instance, limestone formations are often consistently drilled at a higher efficiency than shale formations. For these reasons, the actual ROP can exceed the SEROP (ROP Efficiencies ≥ 100%).

3.9 Outline of Framework

As shown in the Figure 1.1, an offset well will be picked up from the specified area of this study. After that, drilling and geological data are gathered from the well site drilling operation by mudlog records and wireline services. The data from mudlog records are normally composed of Formation legends, Revolution per Minute while drilling (RPM), Weight on Bit (WOB), instantaneous Rate of Penetration (ROP), Torque (T), and operation time log while wireline services provide geological data such as types of formation, water saturation, resistivity, and formation properties. Finally, these data are input into RMA software in order to construct drilling RMA model.

After finish an offset well model construction process, the model will be simulated by adjusting bit sliding coefficient value to generate the predicted ROP model with the aim of matching to actual ROP deriving from an offset well data. In this stage, ROP ratio or ROP efficiency will be the decision tool utilizing with the Cumulative Distribution Function (CDF) analysis in order to find an appropriate bit sliding coefficient for the selected drilling bit.

Once properly bit sliding coefficient is identified, drilling optimization model is generated under ROP specific energy concept by recommending drilling parameters and operation guidelines with the purpose of maximize drilling ROP and maintain bit life. Afterward, actual field orientation is the next step to prove and validate this model. Lastly, conclusions and recommendations for the further study will be provided and discussed.

CHAPTER IV

RESULTS AND DISCUSSION

This chapter presents the method of Bit Sliding Coefficient estimation, RMA model construction and implementation. At the end of this chapter also provides optimization model execution, validation, and performance look back discussion.

4.1 Specified Area of Study

This section introduces background and information of the study area which is located in the Northern Petroleum Licensed Area (PLA), Gulf of Thailand.

4.1.1 Geological Background

Figure 4.1 shows the specified area of this study which is located in the northern part of whole concession area while Figure 4.2 shows Time Structure map with Contour Interval of this area.

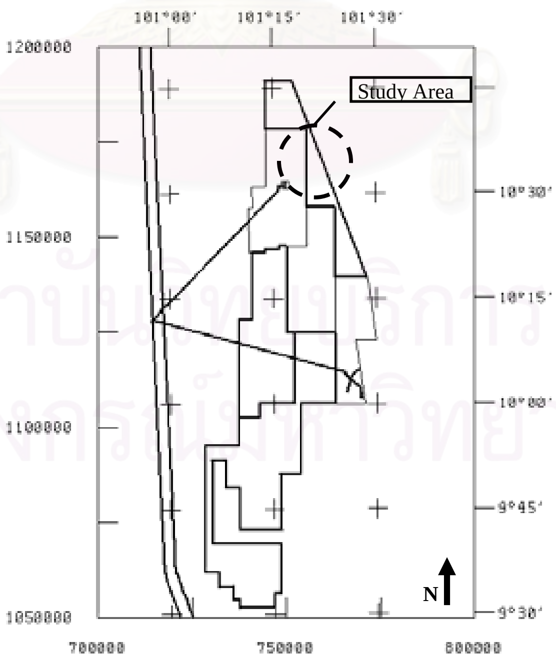

Figure 4.1: Specified study area map.

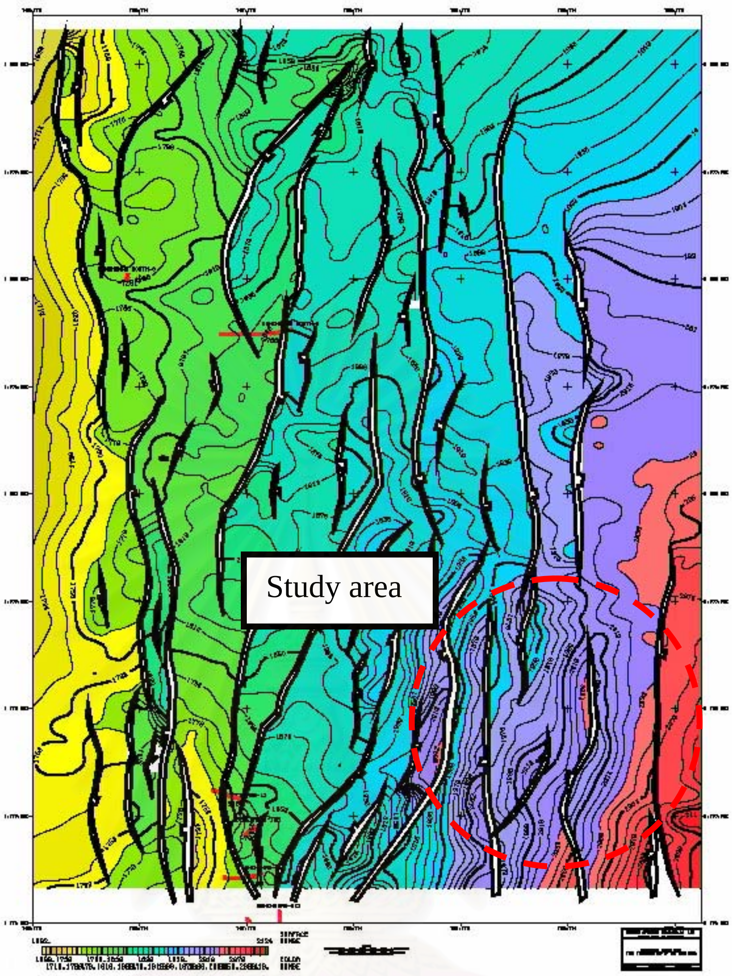

Figure 4.2: Time structure map with contour interval.

Area of study is proposed in the eastern part of a group of west dipping fault block as shown in Figure 4.2. The location will be drilled to test a north south trending fault block located about 3 km to the east of the previous exploration project. In addition, high amplitude seismic events indicated good sand development which is targeted within this fault block. The main reservoirs in this area are expected to be Mid and Lower Miocene age fluvial sediments. These sands were deposited as meandering fluviatile sands in a non-marine environment of deposition. Secondary objectives are the deeper sands within the Top Lacustrine Sequence.

Next section introduces geological data and compressive strength correlation in this area which are derived from previous exploration wells drilled.

4.1.2 Formation Compressive Strength Correlation

This study utilizes the Unconfined Compressive Strength (UCS) of rock as a fundamental parameter to construct drilling optimization model. It is important to understand geological properties background before further study will carry on. Thus, UCS values generated from wireline loggings are collected from numbers of wells drilled in this area. Figure 4.3 exhibits UCS value versus True Vertical Depth Subsea (tvdss) plots which are derived from five exploration wells drilled in the area. It indicates that in this area has incremental trend of UCS in the same manner starting from 2,000 psi at 5,000 ft tvdss to approximately 12,000 psi. at 9,500-10,000 ft tvdss.

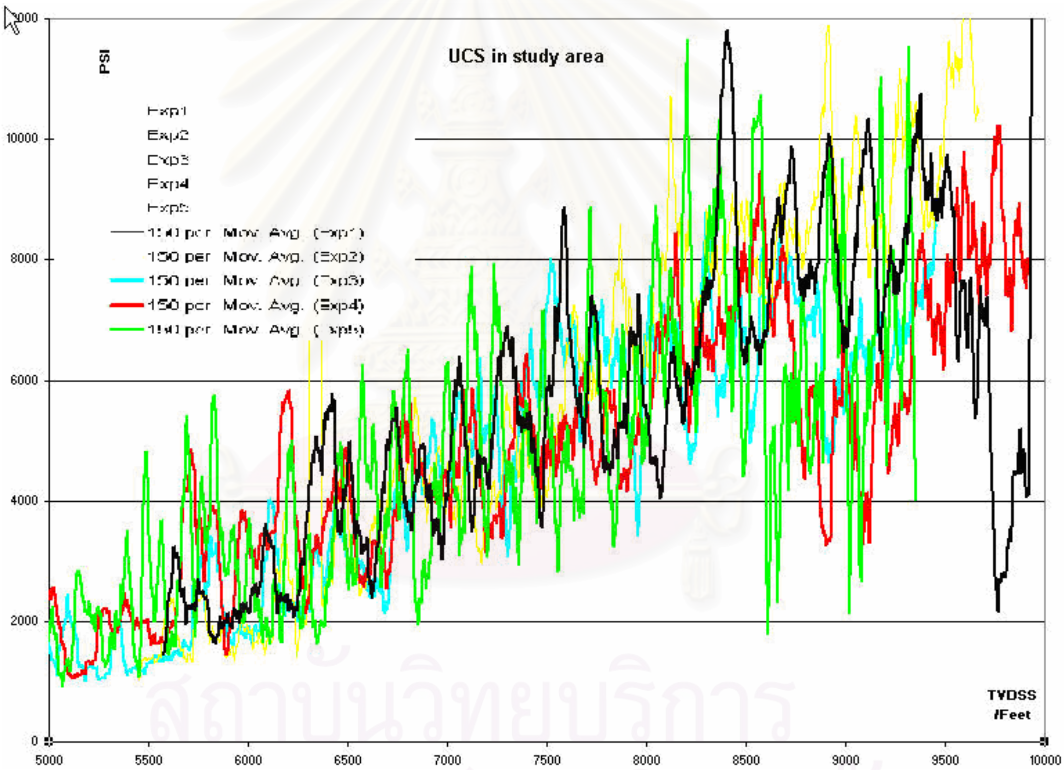

Figure 4.3: Unconfined Compressive Strength (UCS) versus True Vertical Depth (TVD) plots for the specified area from 5 exploration wells.

The lithology legend from mud logging indicates that formations are composed of the majority of sandstone and claystone sequences with the minority of coal beds. These data have to be noted that they were collected from 6-1/8 inch diameter hole drilled or production hole because of mud logging and wireline logging data are available only in this section.

4.2 Gathering Data from Well-A (Offset well)

In order to determine Bit Sliding Coefficient (μ), Well-A is chosen to be an offset well for this study. This well is located in the specified area and considered as an exploration well.

4.2.1 Well-A General Information and Geological Background

The objective of Well-A is to identify core reserves necessary to go forward with a new production platform. The results of this well will also be utilized to acquire the production license for this platform.

Well-A is proposed in the eastern part of a group of west dipping fault block as shown in figure 4.2. The location will test a north south trending fault block located east of the area prospect, locating in a structurally high position of the 3-way closure on an untested fault block. The programmed TD is proposed at 11,693 ft md (approximately 9,999 ft tvdss). The reservoir section is expected to occur within the Miocene red bed sequence and underlying gray shale section (Upper Lacustrine). The expected stratigraphic level at TD is in the upper lacustrine sequence. The general pore pressure profile in the area is taken from standard curves developed for this area drilling campaign. These curves were established from measured formation pressure data (FT & DST) from wells in this field and elsewhere in the concession area as shown in the Figure 4.4.

The drilling program is planned to drill along a high side fault trap to the West direction. Surface casing setting depth is planned to be set at approximately 5,600 ft True Vertical Depth from Rotary Table (tvdrt). Figure 4.5 shows well-A trajectory which will be kicked off from the surface casing shoe with hold angle bottom hole drilling assembly. Finally, the logging program is composed of Quad-Combo (AIT-BHC-LDT-CNL-GR-LEHQT), RFT, and CSAT. The result from wireline logging yields data for input in RMA model building together with mud logging data. This part of RMA model will be prepared and monitored closely by Formation Evaluation Specialist (FES).

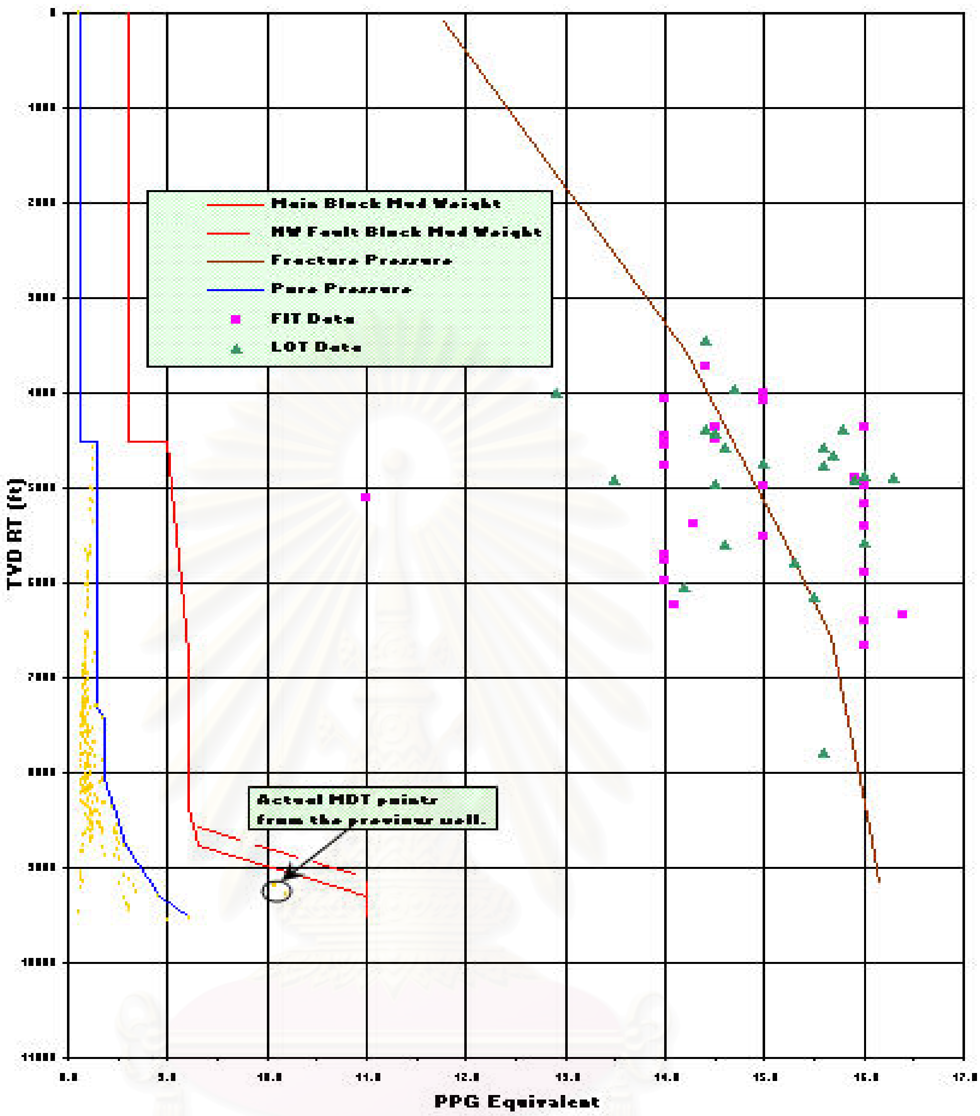

Figure 4.4: Pore Pressure, Fracture Gradient, and MW schedule plots.

4.2.2 Well-A Drilling and Bit Performance

Drilling performances from Well-A is presented as follow:

Well-A is reached TD at 11,600 ft md (10,041 ft tvdrt) with Mud Weight (MW) schedule from 8.6 PPG to 11.0 PPG. Drilling bits used in production section are composed of two runs of 4-blade matrix body bit type. The first bit was pulled out of hole at 9,800 ft md (8,533 ft tvdrt) due to drillstring washed out after stuck pipe problem. The average ROP from start drilling to this point is 146 fph and dull grading is 1-1-NO-A-X-I-NO-WO. The second bit is drilled to TD with dull grading is 1-1-CT-N-X-I-NO-TD with an average ROP of 103 fph.

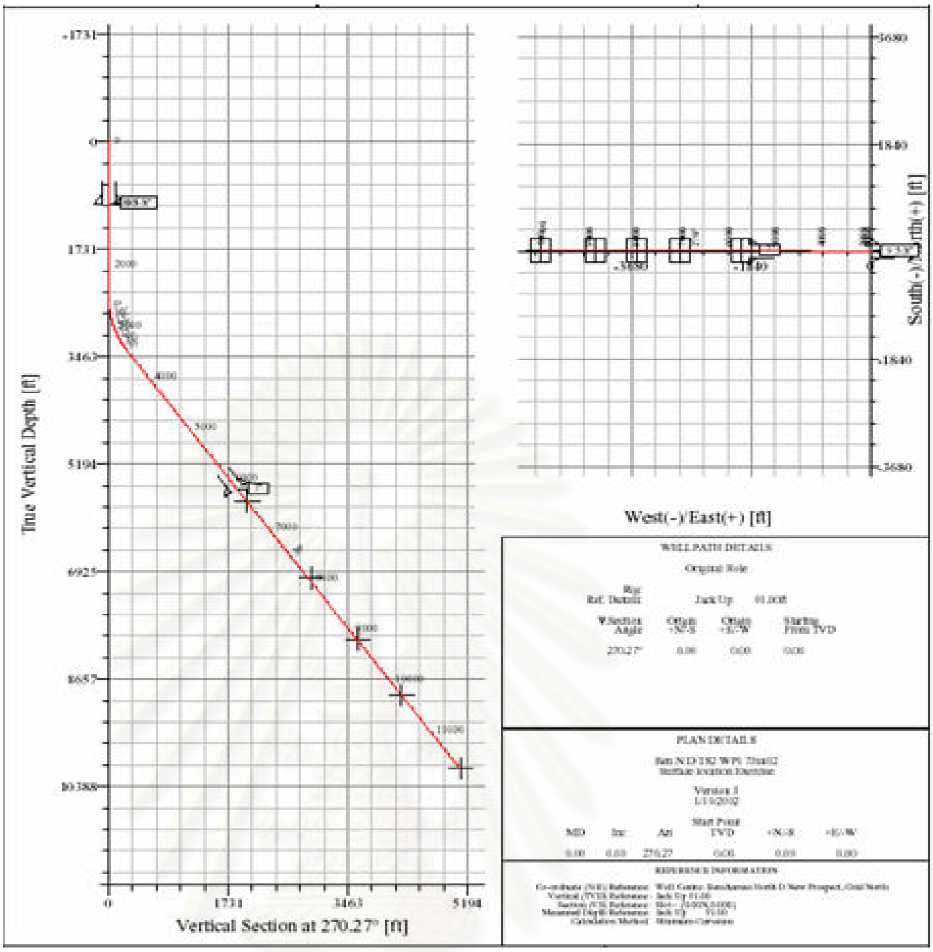

Figure 4.5: Well-A trajectory.

4.2.3 Building RMA Model for Well-A

After Well-A drilling and completion program is completed, minimum data requirements to construct RMA model are collected from mud logging, wireline logging, and drill log recorded. The model building processes are included of geological model part and drilling optimization part.

For example, RMA model for Well-A from depth 6,100 ft md to 7,000 ft md is constructed as shown in the Figure 4.6 but the completed hole interval model is shown in the Appendix A section.

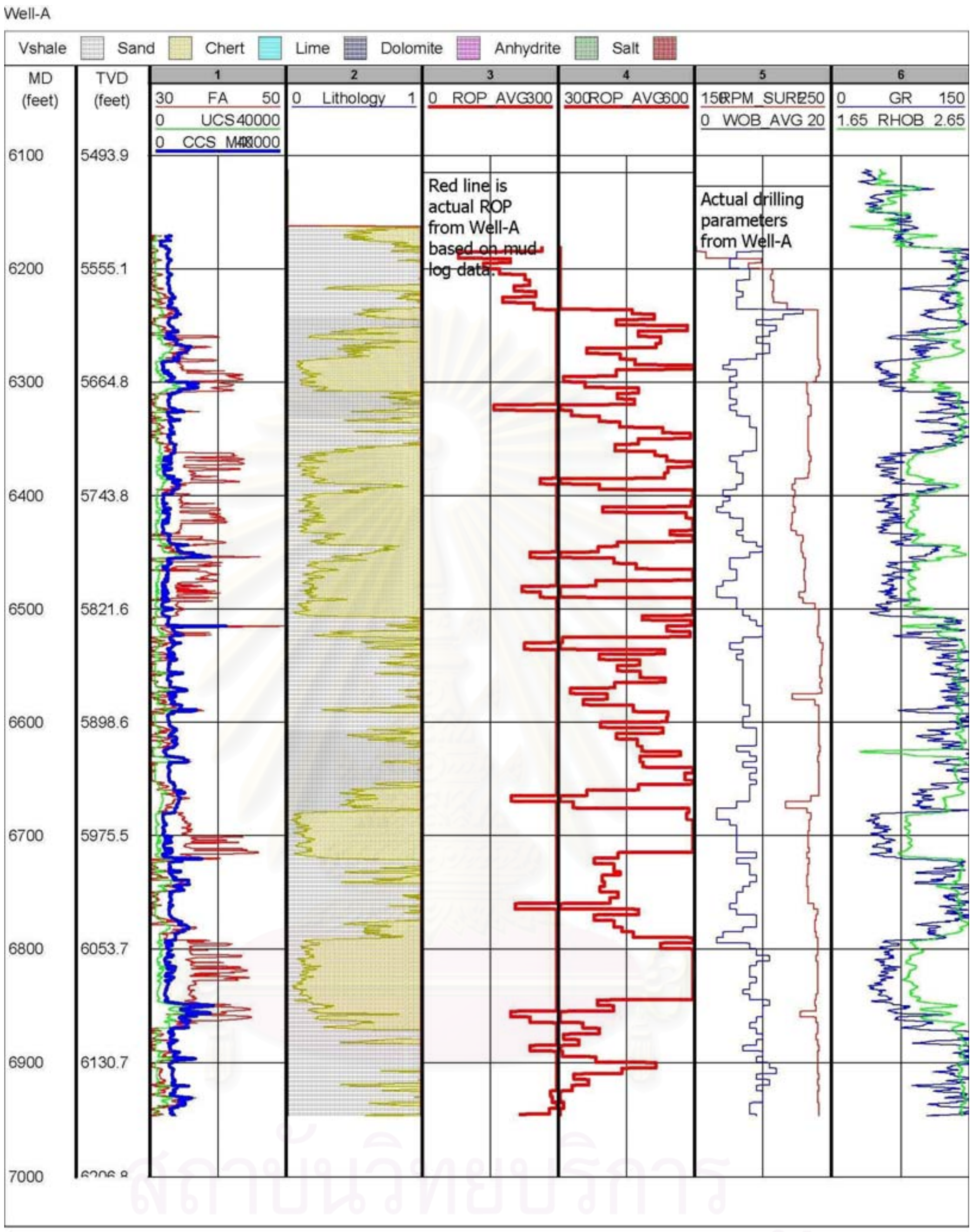

Figure 4.6: RMA model for Well-A from depth 6,100 ft md to 7,100 ft md.

The above RMA model plot for Well-A is composed of seven graphical columns which are

a) Measure depth (MD)

This column shows MD depth of Well-A which is input from directional drilling survey data.

b) True Vertical Depth (TVD)

This column presents TVD depth of Well-A which is input from directional drilling survey data.

c) Unconfined Compressive Strength (UCS), Confined Compressive Strength (CCS), and Formation Abrasivity (F_{ang})

This column shows UCS, CCS, and F_{ang} magnitudes for Well-A at each depth. The plots are calculated from well logging data obtained from the drilling site based on appropriate correlations.

d) Lithology legend

This column shows lithology legend for Well-A at each depth.

e) Rate of Penetration (ROP)

This column shows an average ROP (fph) for Well-A which is obtained from instantaneous recorded from mud logging while drilling.

f) Surface RPM and Average WOB

This column shows surface RPM (rpm) and WOB (x1,000 lbf) while drilling for Well-A which are obtained from mud logging data.

g) Gamma Ray (GR) and Bulk Density (RHOB)

This column shows GR and RHOB at each depth which are derived from wireline loggings data.

4.2.4 Well-A Discussion and Observation

The summary of result from Well-A is shown in the Table 4.1 below. As mentioned earlier, this well was drilled and reached TD with the total of two bits trip. However, an observation from dull grading result indicates that both bits are still in-gauge and having good cutter conditions.

Besides, surface RPM while drilling were run at high speed limit (200-250 rpm) with no lithology abrasivity guidelines.

In addition, an average ROP for the second bit run is 30 percents lower comparing to the first run.

Table 4.1: Summary of results from Well-A drilling.

Well	**A**
Surface casing setting depth, ft	5594
First bit run - Feet drilled, ft - ROP, fph - Bit grading - TVD out, ft - Drilling time, hrs Second bit run - Feet drilled, ft - ROP, fph - Bit grading - TVD out, ft - Drilling time, hrs	4 blades type - 3,580 ft - 146 fph - 1-1-NO-A-X-I-NO-WO - 8533 ft - 24.5 hrs 4 blades type - 1,852 ft - 103 fph - 1-1-CT-N-X-I-NO-TD - 10,041 ft - 18 hrs
Total drilling time, hrs	42.5
ROP equivalent, fph	127
Surface running RPM, rpm	200-250
Avg. applied WOB, x1000 lbf	4-12

According to RMA model from Well-A, determining Bit Sliding Coefficient (μ) process can be accomplished by simulating ROP model by varying μ value in the ROP calculations and using statistical computations in order to perform actual ROP and simulated ROP matching. This process will be presented and discussed in the next section.

4.3 Determining Bit Sliding Coefficient (μ)

One of the objective of this study is to determine Bit Sliding Coefficient (μ) feature of the particular bit type. This procedure utilizes Well-A RMA model which is constructed previously to determine μ value together with statistical analysis methods.

At the beginning, μ is input into the model with varying value ranged from 0.5 to 2.0 with the purpose of generating ROP model based on Passier's correlation. Then, the simulated model result is compared and matched to actual model. ROP Efficiency or ROP ratio which is the ratio between actual to predicted ROP is used as a criterion to determine appropriate μ value for this bit. For instance, the result of simulated ROP model from sliding coefficient value input equal to 1.0 and 1.45 are shown in the Figure 4.7 in yellow and green lines, respectively while the actual ROP is shown in red.

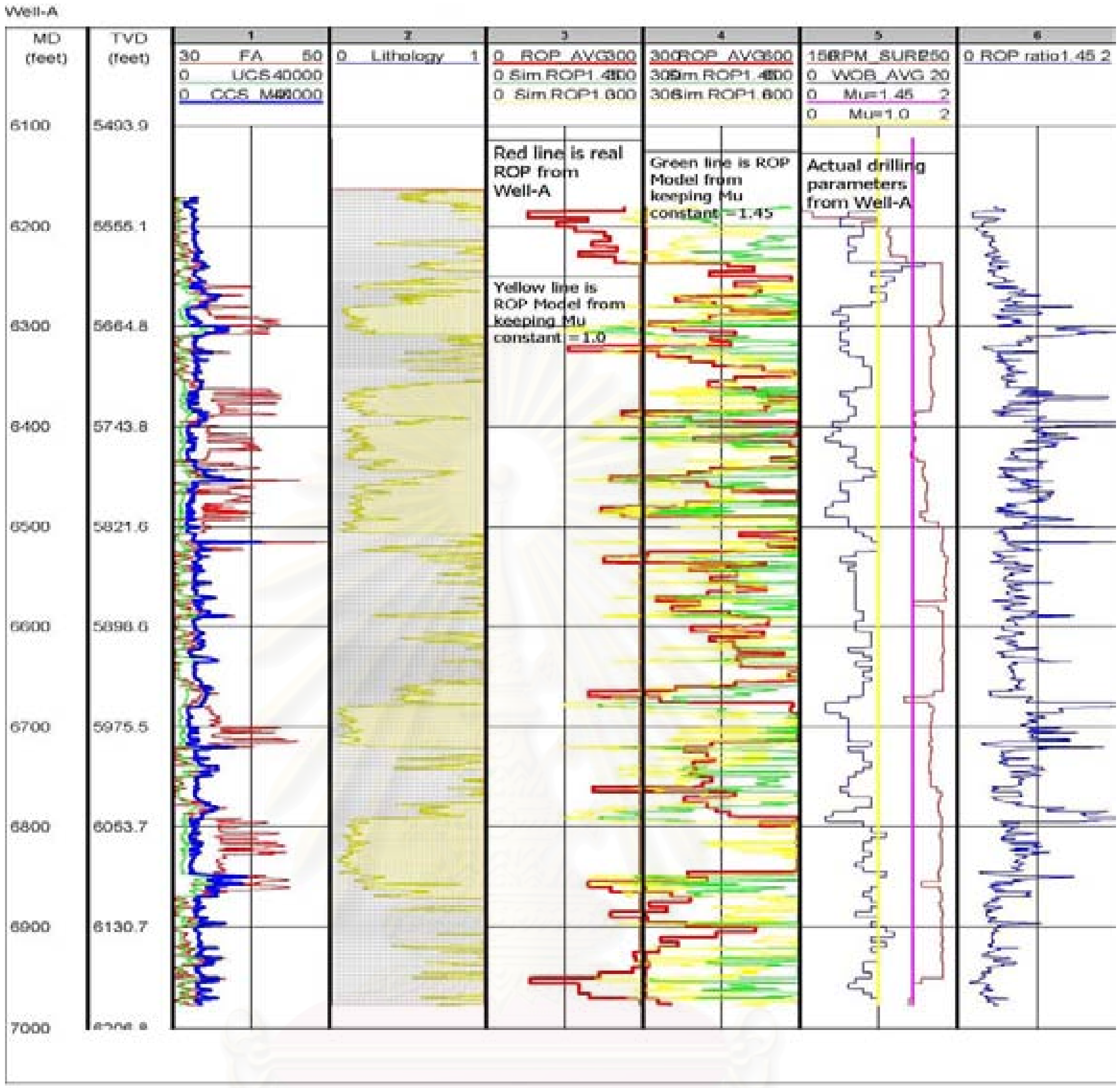

Figure 4.7: Simulated ROP model comparison with μ = 1.0 and 1.45.

According to ROP graphical matching results, statistical analysis of ROP ratio are also calculated and presented in Table 4.2 below. The table shows results which are composed of Mean, SD, and Variance of ROP ratio generating from μ value equal to 0.5 to 2.0. The criteria to estimate an appropriate μ in this study are to consider ROP graphical matching together with the statistical analysis of ROP ratio.

As shown in the Figure 4.7 and Figure B in the Appendix section, μ equal to 1.45 gives a correspondent graphical matching between simulated and actual ROP model while considering statistical analysis outcomes μ should be in the range from 1.3 to 1.4 based on Mean, SD, and Variance answers as shown in the Table 4.2.

Table 4.2: Statistical results from varying μ value.

Input μ / Statistical ROP ratio	0.5	1.0	1.3	1.4	1.45	1.5	1.7	1.8	2.0
Mean	2.38	1.19	0.91	0.85	0.82	0.79	0.70	0.66	0.59
SD	1.56	0.78	0.60	0.56	0.54	0.52	0.46	0.43	0.39
Variance	2.43	0.61	0.36	0.31	0.29	0.27	0.21	0.19	0.15

To identify data distribution, Cumulative Distribution Function (CDF) plot is one of the statistical methods to scrutinize how data is distributed. In this situation, the proportion of the sample that falls into 10^{th}, 50^{th}, and 90^{th} percentiles are shown in the Table 4.3. Besides, Figure 4.8 also presents an example of distribution curve of ROP ratio when μ equal to 1.40. The plot indicates the probability of approximately 80 percent that ROP ratio fall into the range of 0.32 to 1.51. In the Appendix D shows the plot of CDF when varying ROP outcome is observed from different sliding coefficient input.

According to ROP graphical matching, statistical calculations, and CDF plots analysis, Bit Sliding Coefficient (μ) value for selected 4-blade bit running in Well-A is estimated in the range of 1.10 to 1.45.

In order to verify this assumption, Well-B will be drilled to get an additional formation stress data. The idea of varying drilling parameters based on lithology dictate in order to maintain bit life will also be applied in this well. Well-B RMA model, drilling results and discussion are presented in the next section. Finally, drilling optimization model will also be generated from Well-A and Well-B lesson learnt and operation observations before implement to Well-C.

Table 4.3: Data distribution of ROP ratio at each percentile.

Percentile \ μ	**1.0**	**1.1**	**1.2**	**1.3**	**1.4**	**1.5**	**1.6**	**1.7**	**1.9**
$\mathbf{P_{10}}$	0.45	0.41	0.38	0.35	0.32	0.30	0.28	0.27	0.25
$\mathbf{P_{50}}$	1.00	0.91	0.83	0.77	0.72	0.67	0.66	0.59	0.55
$\mathbf{P_{90}}$	2.12	1.93	1.77	1.63	1.51	1.41	1.32	1.25	1.18

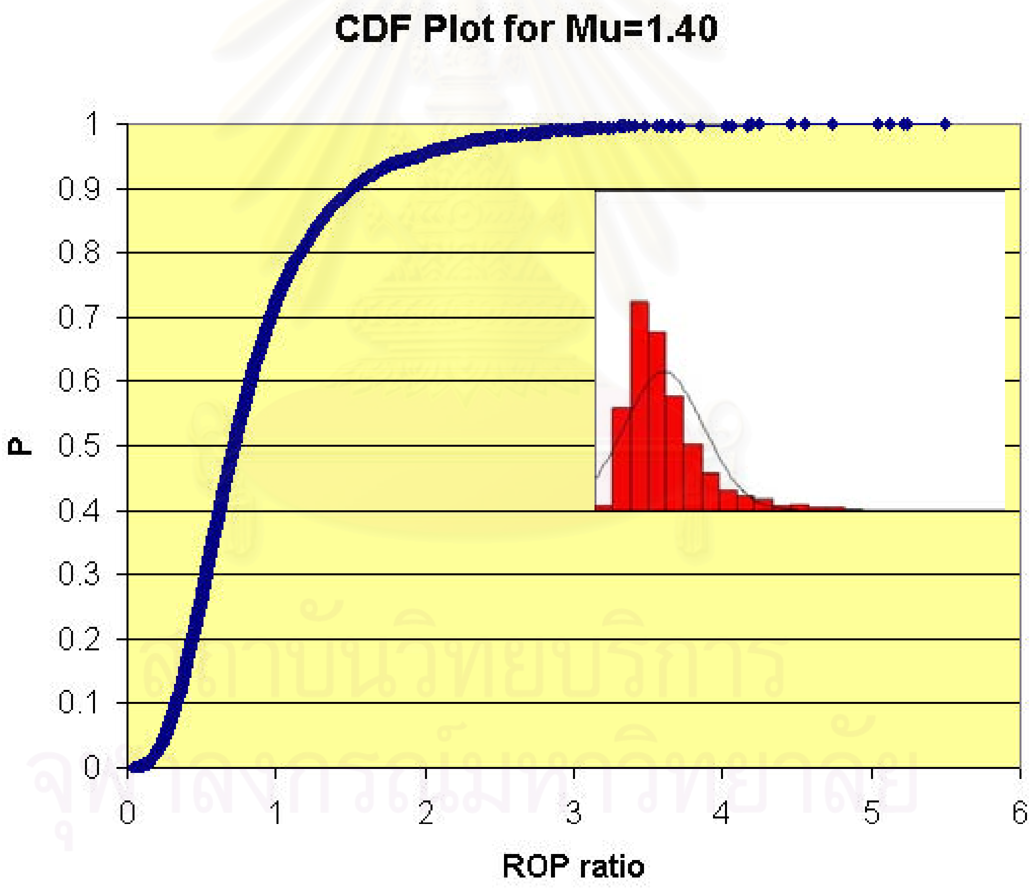

Figure 4.8: Cumulative Distribution Function (CDF) plot for ROP ratio of μ = 1.40.

Note: CDF plots for other cases are shown in the Appendix D section.

4.4 Building RMA Model for Well-B (Tested offset)

Well-B RMA model construction step of works are presented as follow:

4.4.1 Well-B General Information and Geological Background

In order to get more drilling data and information in the area of study, Well-B is planned to drill with general information as follow:

Well-B is located 6.5 km northeast of Well-A. The well trajectory is planned to drill along high side fault block to the north direction as shown in Figure 4.9. Production hole section drilling bottom hole assembly is hold angle type which is the same configuration used in Well-A. Well trajectory purpose is to keep constant hole angle and straight direction after drill out the 7 inch surface casing shoe. Well TD is planned at 11,451 ft md (9,414 ft tvdss) with MW schedule starting from 8.6 PPG to 9.6 PPG.

The reservoir section is expected to occur within the Miocene red bed sequence and underlying gray shale section (Upper Lacustrine) as same as Well-A. The expected stratigraphic level at TD is also in the upper lacustrine sequence. The general pore pressure profile in the area is taken from standard curves developed for this area drilling campaign. These curves were established from measured formation pressure data (FT & DST) from wells in this field and elsewhere in the concession area as shown in Figure 4.4.

Well-B model is used to compare and to correlate data with Well-A in order to conclude Bit Sliding Coefficient (μ) value estimation. Moreover, the drilling parameters is controlled based on lithology dictate by slow down RPM and increase WOB in high formation abrasivity zone which is indicated by high magnitude of F_{ang}. Finally, optimization model is constructed from Well-B data and drilling improvement is implemented in Well-C.

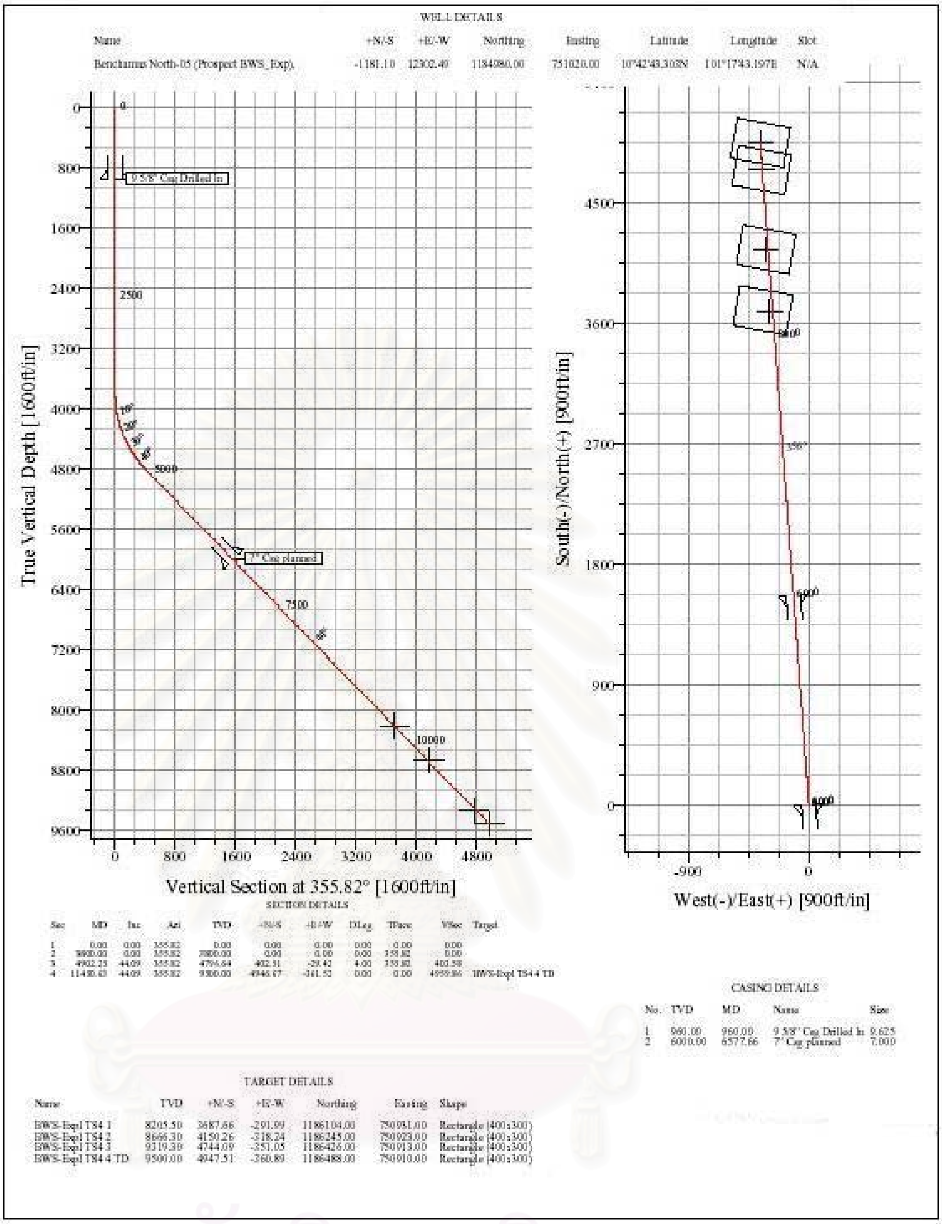

Figure 4.9: Well-B trajectory.

4.4.2 Well-B Drilling and Bit Performance

Well-B was drilled to target depth at 11,342 ft md (9,479 ft tvdss) with one bit run. Bit was pulled out with dull grading of 1-2-WT-T-X-I-WT-TD and in-gauge diameter. The drilling parameters were adjusted in correspondent with lithology dictated by using Well-A lithology model as a parameter guideline. Table 4.4 presents summary of results from Well-B drilling operation.

Table 4.4: Summary of results from Well-B drilling.

Well	**B**
Surface casing setting depth, ft	5,979
First bit run	4 blades type
- Feet drilled, ft	- 4,757 ft
- ROP, fph	- 168 fph
- Bit grading	- 1-2-WT-T-X-I-WT-TD
- TVD out, ft	- 9,479 ft
- Drilling time, hrs	- 28.5 hrs
Second bit run - Feet drilled, ft - ROP, fph - Bit grading - TVD out, ft - Drilling time, hrs	N/A
Total drilling time, hrs	28.5
ROP equivalent, fph	168
Surface RPM, rpm	Vary with formation dictated
Avg.WOB, x1000 lbf	Inverse with RPM value

4.4.3 Building RMA Optimization Model for Well-B

After Well-B drilling and completion operations are completed, minimum data requirements for building RMA model are gathered and refined. Well-B RMA model is constructed and optimized. Figure 4.10 shows an example of Well-B RMA model with graphical data plot in each column (Note: Full borehole plot is shown in the Figure C in Appendix section). Each column descriptions are the same as mentioned earlier in Well-A part except the column number 3, 4, 5, and 6.

Column number 3 and 4 shows the comparison of actual ROP from Well-A in red line and actual ROP from Well-B in blue line. In addition, Specific Energy ROP (SEROP) scheme is shown in the green line. This SEROP prediction is estimated based on Passier's ROP specific energy equation and drilling operating parameters limitations.

As shown in the Figure 4.10, the predicted SEROP model is generated and calibrated to match with actual ROP from Well-B. Furthermore, recommended parameters are also plot with actual parameters for the purpose of comparison.

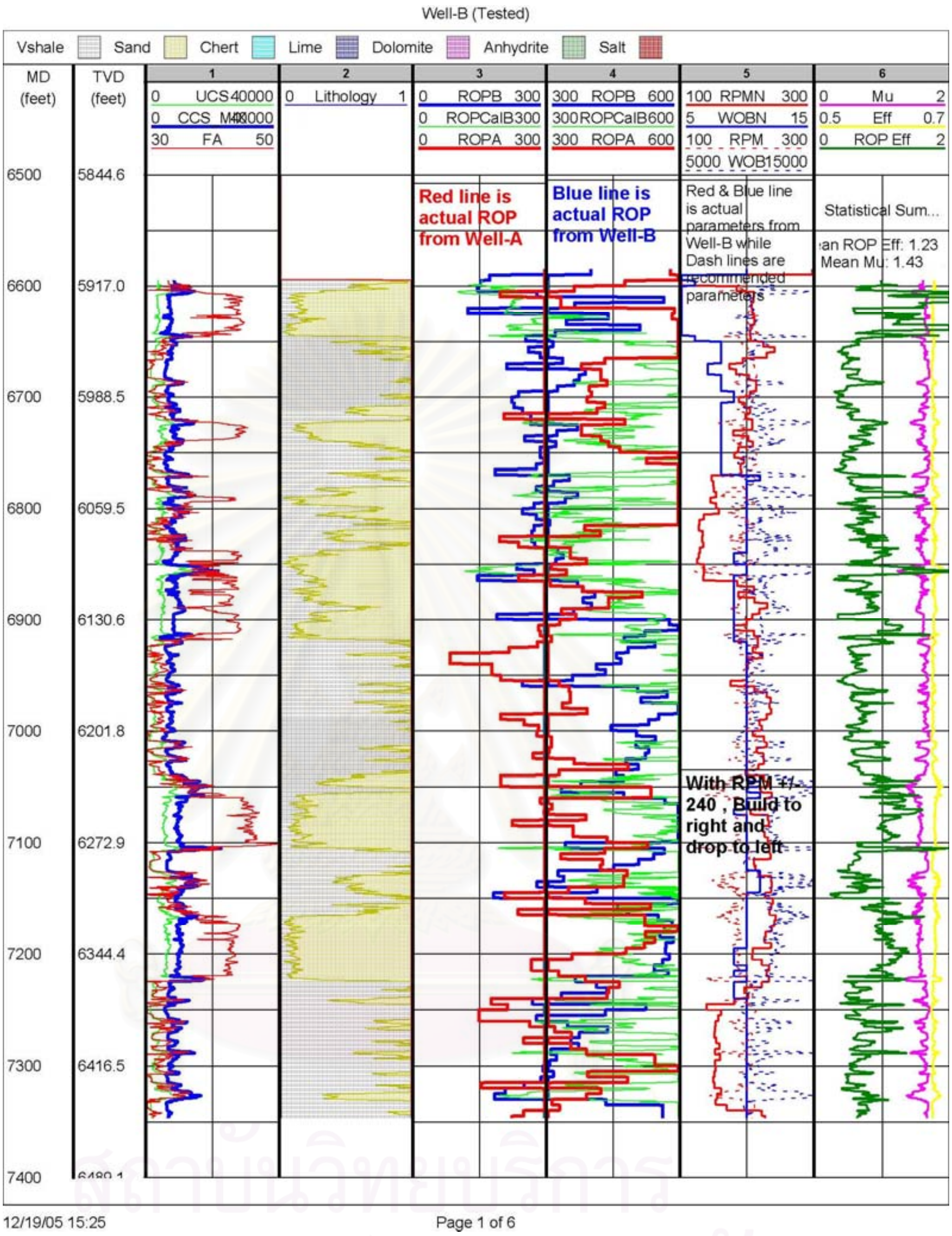

Figure 4.10: Well-B RMA model from depth 6,500 ft md to 7,400 ft md.

Actual and recommended drilling parameters are shown in the column number 5. Red and Blue line represent actual drilling RPM and WOB from Well-B drill log records. Red dash and Blue dash line are the recommended drilling parameters based on the specific energy equation. These parameters will be carried over to be implemented on Well-C which is presented in the next section.

Column number 6 shows Bit Sliding Coefficient (μ) calculated from SEROP. Moreover, the statistical calculations show that:

a) An average ROP ratio is equal to 1.23, and

b) An average Bit Sliding Coefficient (μ) is equal to 1.43.

4.4.4 Well-B Discussion and Observation

The average ROP for Well-B is equal to 168 fph while average ROP for Well-A is 147 fph equivalent. This improvement comes from appropriate drilling parameters while drilling, lithology guidelines from an offset well, and previous drill log records.

Figure 4.11 shows UCS comparison between Well-A and Well-B versus tvdss plot. The plot indicates maximum UCS magnitude at approximately 8,500 tvdss which is correspondent with Top Gray Shale estimated depth. After this point, UCS magnitude tends to be lower until reaching TD at each well.

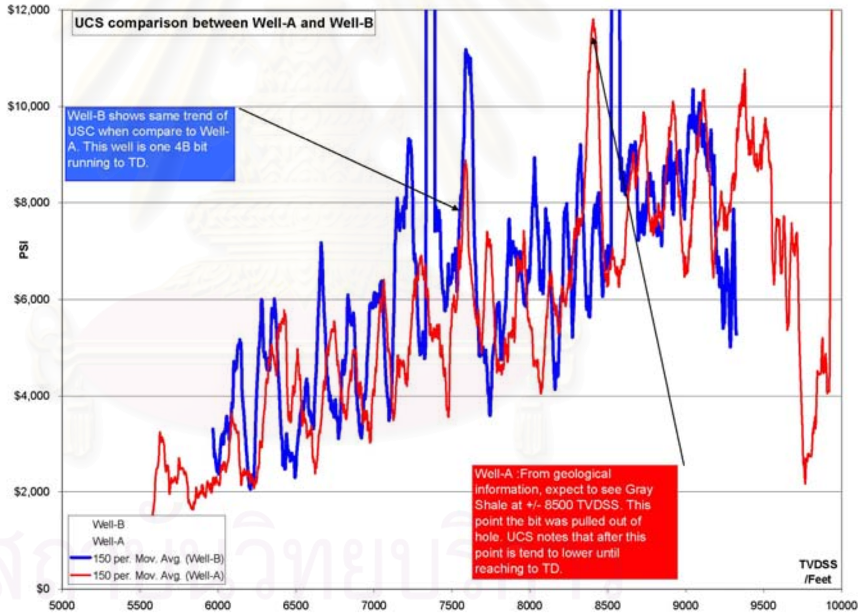

Figure 4.11: UCS comparison between Well-A and Well-B.

Well-B reached TD with a single bit run which resulted the majority of drilling cost saving by eliminating the second bit cost and trip time in approximately of 52,000 dollars comparing to Well-A.

In addition, the drilling footage in Well-B is 4,757 ft md comparing to 3,580 ft md in Well-A for the first bit run.

The result shows the average Bit Sliding Coefficient (μ) is in the range from 1.10 to 1.45 and SEROP model is practical and reliable.

The model also recommends varying drilling parameters in order to maintain bit life and maximize ROP efficiency. This is the new approach in drilling practices comparing to the previous.

According to these results and improvements from Well-A and Well-B, optimization model and operating guidelines from both well are planed to be implemented in Well-C. Results are presented and discussed in the next section.

4.5 Drilling Optimization Model

According to Well-A and Well-B drilling results, RMA model provides predicted ROP based on specific energy correlations. The program also recommends appropriate drilling parameters which are WOB and RPM while drilling in order to maintain bit life and reach maximum efficiency.

Drilling optimization model is constructed as a guideline for development drilling program in this area using RMA model analysis. The model suggests proper operating parameters, lithology legend, stick slip and high abrasiveness area, and potential ROP while drilling.

Well-C is planned as a new fault block well to test and develop possible hydrocarbons at a location approximately 2.5 km NW of the development platform.

The well trajectory is placed on the high side of a down to the west normal fault as shown in the Figure 4.12. The structural trap for the well is defined as having three-way closure that is fault sealed to the west and dip closed to the east. It is similar to the Well-A closure structure but about 1.5 km to the east. Next section introduces Well-C drilling optimization model and operating guidelines.

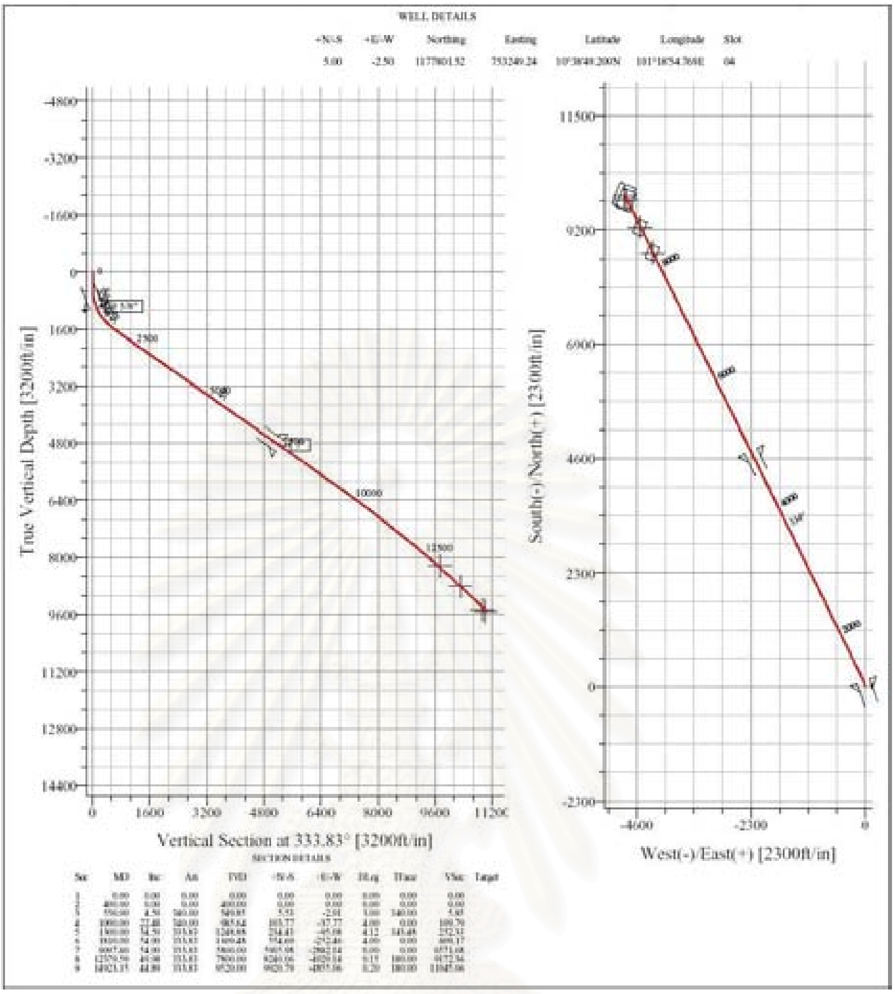

Figure 4.12: Well-C trajectory.

4.5.1 Well-C Operation Instructions

Table 4.5 presents the recommended surface RPM and WOB for Well-C drilling operation which are obtained from Well-A and Well-B RMA models. The operation instruction also provides high abrasivity and stick slip zones indicated from both previous wells results.

Moreover, the estimated drilling time excluding connection is shown in the Table 4.5 as well. This estimated time is calculated from expected ROP in that drilling interval.

Drilling optimization model for Well-C is divided into four sections by tvdss as following:

1. Section I (5,000’-5,800’ tvdss)

There is no concern of formation abrasivity, stick slip, and impact in this section because it is still in the shallow hole section. UCS is expected in the range of 2,000-3,000 psi and F_{ang} is about 30 referred to RMA model from Well-A and Well-B. Expected ROP in this section is 400-450 fph with estimated drilling time of 3 hrs. Recommended drilling parameters are applying WOB at 8,000-10,000 lbf and RPM at 200+/- rpm.

2. Section II (5,800’-6,500’ tvdss)

This section is in the low to moderate abrasivity zone. UCS and F_{ang} are estimated at 4,000-5,000 psi and 40-45, respectively. Drilling parameters are suggested to keep WOB around 10,000-12,000 lbf and RPM at 200+/- rpm. ROP and drilling time are estimated at 300-350 fph and 4 hrs, consecutively.

3. Section III (6,500’-7,900’ tvdss)

Section III enters moderate to high formation abrasivity zone with many layers of sandstone having F_{ang} of 40-45 and UCS is about 5,000-8,000 psi. Optimization model recommends applying WOB 12,000-14,000 lbf and RPM at 150+/- rpm. Expected ROP is 200-220 fph and estimated drilling time for this section is 9 hrs.

4. Section IV (7,900’-9,500’ tvdss)

This section is in the continuous zone of high formation abrasivity and impact. UCS is estimated in the range of 8,000’-12,000’ psi especially under 8,500’ tvdss. Dark gray shale is expected to see at 8,500’ tvdss based on previous drill log records. 14,000-15,000 lbf of WOB and RPM at 150+/- rpm are recommended to operate in this section. Estimated ROP is 150-200 fph with 9 hrs. estimated time to drill this section.

Table 4.5 presents the summary of operation instructions as mentioned earlier in this section.

Table 4.5: Drilling operation guidelines for Well-C.

True Vertical Depth, tvdss	**Recommended Drilling Parameters**	**Operating Guidelines**	**Expected ROP, fph**	**Estimated Drilling Time, hrs**
5,000’ to 5,800’	- Surface RPM in the range of 200+/- rpm. - Applied WOB in approx. 8,000 to 10,000 lbf.	- Low stick slips and impact lithology. - No formation abrasivity concern in this zone.	400-450	3+/-
5,800’ to 6,500’	- Surface RPM in the range of 200+/- rpm. - Applied WOB in approx. 10,000 to 12,000 lbf.	- Low to moderate stick slips and impact lithology. - Moderate formation abrasivity concern in this zone.	300-350	4+/-
6,500’ to 7,900’	- Surface RPM in the range of 150+/- rpm. - Applied WOB in approx. 12,000 to 14,000 lbf.	- Moderate to high stick slips and impact lithology. - Moderate to high formation abrasivity concern in this zone.	200-220	9+/-
7,900’ to 9,500’	- Surface RPM in the range of 150+/- rpm. - Applied WOB in approx. 14,000 to 15,000 lbf.	- High stick slips and impact lithology. - High formation abrasivity concern in this zone.	220-250	9+/-

Drilling results and performance from Well-C are presented and discussed in the next section.

4.5.2 Well-C Drilling and Bit Performance

Well-C is drilled to target depth at 14,900 ft md (9,500 ft tvdrt) with one bit run and total footage of 7,375 ft md from 7 inch surface casing shoe. Drilling bit came out with dull grading of 0-1-CT-N-X-I-WT-TD and in-gauge diameter.

Drilling parameters were run following the operation instructions as shown in the Table 4.5 except from 8,100 to 9,500 ft tvdrt due to well path directional concern. Directional driller would like to maintain surface RPM at 150 rpm and WOB at 10,000 lbf in order to keep the hole angle constant to slightly drop to projected TD.

Table 4.6 exhibits summary of results from Well-C drilling operation. Obviously, bit came out in a good condition after 45.5 hours running. An average drilling ROP is 162 fph which is about 28 percents improvement comparing to Well-A and almost two times of total footage drilled.

Table 4.6: Summary of results from Well-C drilling.

Well	**C**
Surface casing setting depth, ft	4,883
First bit run	4 blades type
- Feet drilled, ft	- 7,375 ft
- ROP, fph	- 162 fph
- Bit grading	- 0-1-CT-N-X-I-WT-TD
- TVD out, ft	- 9,517 ft
- Drilling time, hrs	- 45.5 hrs
Second bit run - Feet drilled, ft - ROP, fph - Bit grading - TVD out, ft - Drilling time, hrs	N/A
Total drilling time, hrs	45.5
ROP equivalent, fph	162
Surface RPM, rpm	150-200
Avg.WOB, x1000 lbf	8-12

4.5.3 Well-C Discussion and Observation

Actual drilling parameters, operating results, average ROP, and actual drilling time including operation observations are presented by section as following:

1. Section I (5,000'-5,800' tvdss)

   Drilling parameters are applied with the surface RPM of 180-200 rpm and WOB of 8,000 lbf. Average ROP in this section is equal to 410 fph with 3 hrs total drilling time which are in accordance with model predictions.

   There is no stick slip problem occurring in this section. Formation sample shows the majority of red claystone beds with minority of sandstone beds.

2. Section II (5,800'-6,500' tvdss)

   Surface RPM and WOB are performed in the range of 200 rpm and 10,000-12,000 lbf, respectively. An actual average ROP in this section is 340 fph with 4.5 hrs drilling time which are in the range of model prediction.

   Formation samples indicate 90 percents of red claystone and 10 percents of gray claystone mixing with sand.

   There are no problems while drilling weather stick slip or directional concern.

3. Section III (6,500'-7,900' tvdss)

   In this section, surface RPM is slow down to 150-200 rpm in order to maintain bit life when drilling into moderate abrasivity zone. Cutting samples show increasing of sandstone portion comparing to previous section. Red and grey claystone are also observed in this section.

   Drilling ROP in this section is reducing from 220 to 170 fph in the last 800 ft tvd due to the directional control problem. Basically, hole angle tends to drop while drilling due to gravitational force acting at the BHA, with the aim of approaching reservoir targets, directional driller wants to gradually increase WOB from 8,000 to 12,000 in order to build hole angle and allows it slightly drop in the last drilling section. Total drilling time in this section is 12.1 hrs which is 3 hrs. more than the estimation due to directional correction time and survey acquiring time.

4. Section IV (7,900'-9,500' tvdss)

   Last section enters high abrasivity and stick slip zone. Cutting samples and drill log recorded show sandstone and shale sequences formation with accumulation of hydrocarbon. Dark gray shale is observed at approximately 8,600 ft tvdss.

Recommended drilling parameters from optimization model are applying 150+/- rpm of surface RPM and 14,000-15,000 lbf of WOB with expected drilling ROP around 220-250 fph. However, according to hole angle alignment problem from previous section, actual input WOB while drilling cannot exceeds 10,000 lbf in order to maintain constant to slightly drop in hole angle. An average ROP in this section is 180 fph with 12.5 hrs of total drilling time.

As shown in the Table 4.7, it can be observed from the drilling results in the last drilling section that WOB is not run following the optimization model recommendation due to directional control. Thus, in order to verify optimization model reliability, additional RMA drilling model will be constructed based on actual drilling parameters applying in this section. In other word, this model will be used to confirm accuracy of the optimization model.

Table 4.7: Summary of drilling operation from Well-C.

True Vertical Depth, tvdss	Actual Drilling Parameters	Lithology Indices and Operating results	Actual ROP, fph	Actual Drilling Time, hrs
5,000' to 5,800'	- Surface RPM is run in the range of 180 to 200 rpm. - Applied WOB is 8,000+/- lbf.	- No stick slip while drilling is observed. - 80% of red claystone with minority of sandstone bed sequences.	410	3
5,800' to 6,500'	- Surface RPM is run at 200 rpm. - Applied WOB is in the range of 10,000 to 12,000 lbf.	- No stick slip while drilling is observed. - 90% of red claystone with minority gray shale with sandstone bed sequences.	340	4.5
6,500' to 7,900'	- Surface RPM is run in the range of 150-200 rpm. - Applied WOB is approx. 8,000 to 12,000 lbf. - Adjust parameter to control hole angle and walk tendency.	- Moderate stick slips and impact lithology are observed while drilling. - 50% of red and gray claystone with 50% of Sandstone with H-C accumulation. - Had difficulties in controlling hole angle and walk tendency.	190	12.1
7,900' to 9,500'	- Surface RPM is run in the range of 150-170 rpm. - Applied WOB is approx. 10,000 lbf in order to drop hole angle.	- Moderate stick slips are observed while drilling. - 60% of red and gray claystone. Dark gray shale is observed at approx. 8,600 ft tvdss with 40% of Sandstone with H-C accumulation.	180-200	12.5

4.6 Optimization Model Validation

According to performance results from Well-C, section I to section III drilling metrics is in accordance with optimization model predictions except in the last section. As mentioned earlier, in order to validate full borehole drilling optimization model, RMA model for the section IV (7,900'-9,500' tvdss) is regenerated with the actual drilling parameters input to evaluate potential drilling ROP and Time for this section.

4.6.1 RMA Model Regeneration

Section IV drilling RMA model is generated as shown in the Figure 4.13. The red line shows expected ROP from specific energy calculations while the blue line represents estimated ROP from actual drilling parameters input. The details of parameter are shown in the Table 4.8 below:

Table 4.8: Optimized and Regenerated model parameters.

Drilling Parameters / **Models**	**Weight on Bit, lbf**	**Revolution per Minute, rpm**
Optimization model	Model recommends applying WOB in the range of 14,000 to 15,000 lbf.	Due to high abrasivity and stick slip in this section, model suggests using RPM at +/- 150 rpm.
Regenerated model	10,000 lbf as applied while drilling.	150 rpm as applied while drilling.

Both models are constructed under controlled parameters condition in order to see the different outcomes from a discrepancy of 4,000-5,000 lbf in WOB. Predicted ROP from both models can be compared the dissimilar result as shown in the Figure 4.13.

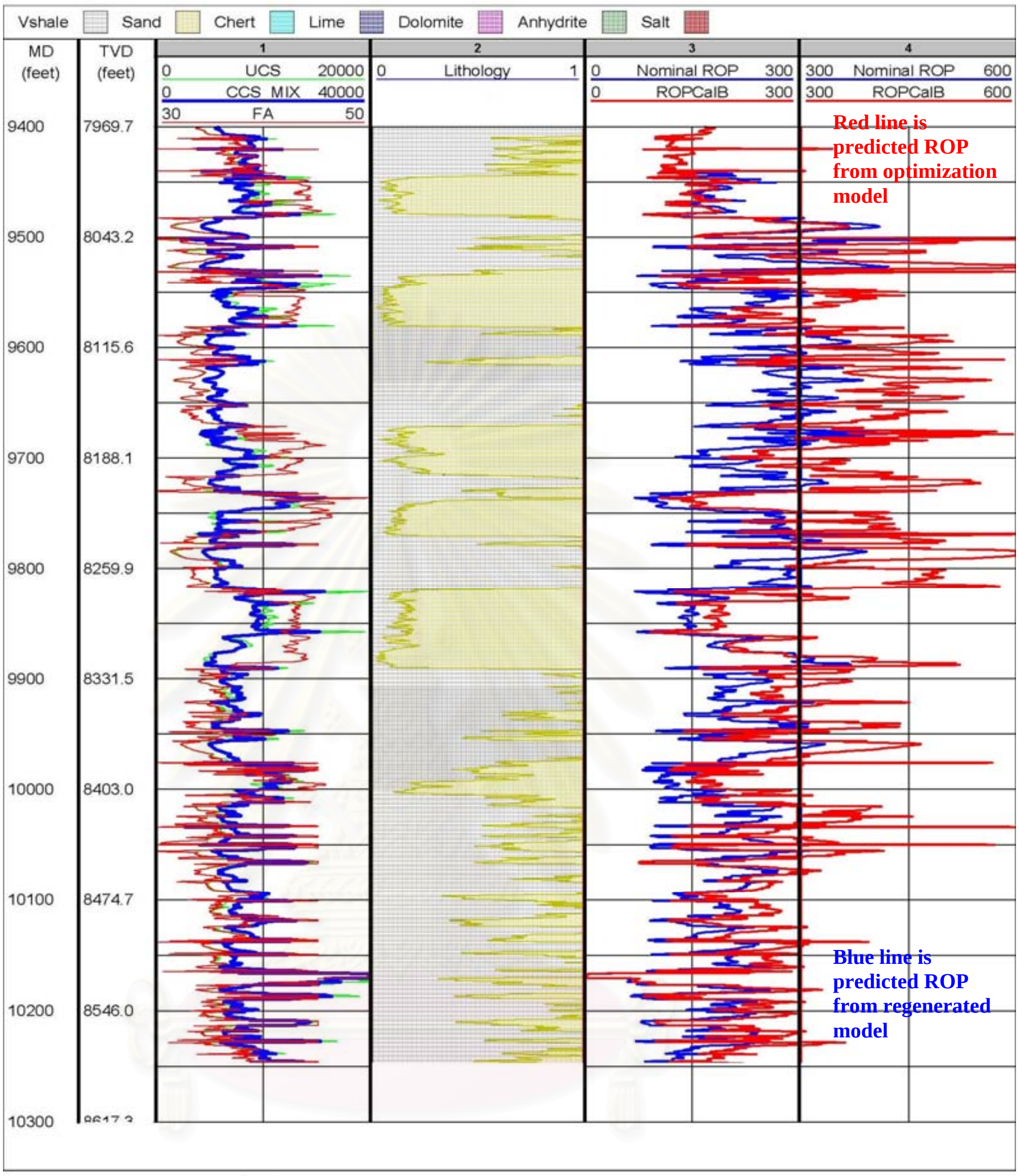

Figure 4.13: Predicted ROP models comparison.

It can be clearly observed from the Figure 4.13 that regenerated model gives the predicted ROP lower than optimization model does. The main reason is come from different in input WOB for each model. The regenerated ROP scheme is used to match up to actual drilling ROP from Well-C in order to prove the RMA model reliability.

Next section presents predicted ROP comparison from each model with actual drilling ROP from Well-C. Estimated drilling time and actual drilling time are also provided.

4.6.2 RMA Optimization Model Validation

The summary of drilling metric results from Optimization model, Regenerated model, Well-C drilling performance in the section IV (7,900'-9,500' tvdss) is presented in the Table 4.9 and 4.10 as follow:

Table 4.9: Actual and Predicted ROP comparison from each model.

Depth, tvdss	Expected ROP from optimization model, fph	Expected ROP from regenerated model, fph	Actual ROP from Well-C drill log recorded, fph
7,900'-8,500'	250-280	200-220	240
8,500'-8,800'	220-250	180-200	210
8,800'-9,500'	180-200	140-160	150

Table 4.10 shows estimated drilling time in this interval which is calculated from expected drilling ROP in each depth broke down scale.

Table 4.10: Actual and Estimated drilling time comparison from each model.

Depth, tvdss	Estimated drilling time from optimization model, hrs	Estimated drilling time from regenerated model, hrs	Actual drilling time from Well-C drill log recorded, hrs
7,900'-8,500'	3.43	3.86	4.00
8,500'-8,800'	1.85	2.15	2.37
8,800'-9,500'	3.85	5.77	6.00
Total, hrs	**9.13**	**11.81**	**12.37**

As shown in the Table 4.10 above, total actual drilling time from Well-C is different from estimated drilling time from optimization and regenerated models by 35 percents and 5 percents, respectively.

These results show the drilling RMA model for this area is practical and reliable for future well planning and drilling operation.

4.7 Discussion

Table 4.11 shows summary of results from Well-A, Well-B, and Well-C drilling operation and performance. As mentioned earlier, Well-B and Well-C was drilled with a single bit run to TD which is an average ROP improvement of 24 percents and 19 percents respectively comparing to Well-A. Dull grading results also indicate good condition of both drilling bit after pass many operating hours in drilling hole. This is because of variable operating drilling parameters input which are based on formation dictate concept.

According to validation process in the previous section, the results illustrate an effective potential ROP scheme with recommended operating parameters deriving from specific energy concept. The model is very useful when using with CPF analysis while conduct drilling operation at well site, especially, when operator encounters critical ROP situation or drilling in high abrasive formation. Therefore, this model can be used in either pre-well planning or post-well performance look back.

The conclusions from the study and recommendations for the further study are presented in the next chapter.

Table 4.11: Summary of results.

Well Name	**A**	**B**	**C**
Surf. Csg. Setting Depth (tvdrt)	5,594	5,979	4,883
First Bit	4-Blade Type (16 mm)	4-Blade Type (16 mm)	4-Blade Type (16 mm)
- Feet drilled (ft)	3,580	4,757	7,373
- ROP (fph)	146	168	162
- Dull grading	1-1-NO-XA-X-IN-NO-WO	1-2-WT-XT-X-IN-WT-TD	0-1-CT-N-X-IN-WT-TD
- TVD out (ft)	8,533	9,478	9,517
- Drilling time (hrs)	24.5	28.5	45.5
Second Bit	4-Blade Type(16 mm)	-	-
- Feet drilled (ft)	1,852	-	-
- ROP (fph)	103	-	-
- Dull grading	1-1-CT-XN-X-I-NO-TD	-	-
- TVD out (ft)	10,041	-	-
- Drilling time (hrs)	18	-	-
Total drilling time (hrs)	42.5	28.5	45.5
ROP Equivalent (fph)	127	168	162
Total drilling time to 9,500'tvdrt (hrs)	35	28.5	45.5
Footage to 9,500 tvdrt (ft)	4,778	4,757	7,375
ROP equivalent (fph), (to 9,500'tvdrt)	136	168	162
Drilling ROP improvement (%)	Offset	24	19

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS

This chapter presents the conclusion of bit sliding coefficient study, drilling performance with statistic comparison, and rate of penetration improvement by RMA implementation from three experiment wells drilled in the Gulf of Thailand. The further study aspect and recommendations are also discussed and reviewed at the end of the chapter.

5.1 Conclusions

The goal of most drilling optimization projects is to reduce hole section cost. To accomplish this goal, the bit optimization process involves determining suitable bit and bottom hole assembly (BHA) combinations, predicting their performance on a footage, rate of penetration (ROP), operational parameters and cost per foot basis, and then determining the best combination of bits and BHA for a proposed well. This has been done for years without quantitative analysis and consideration of rock properties.

This study simulates the drilling models and operation guidelines based on formation specific energy concept which is derived from rock mechanics algorithm study. The results from actual field orientation in this study are concluded as follow:

1. In the area of study, The Confined Compressive Strength (CCS) magnitude is estimated in the range of 5,000 psi to 40,000 psi or about two times of The Unconfined Compressive Strength (UCS). The Friction Angle (F_{ang}) magnitude is observed in the range from 30 to 50.
2. According to lithology legend records, the formation in the area of study is comprised of the majority of sandstone and claystone bed sequences with the minority of coal bed.
3. The Bit Sliding Coefficient (μ) value for the 4-blade bits which are utilized in Well-A, B and C is estimated in the range of 1.10 to 1.40 according to ROP ratio calculation in the RMA model and statistical analysis from the Cumulative Distribution Function (CDF) plots. RMA model from Well-B

indicates an average of μ value is equal to 1.43 which is used to construct optimization model applying to Well-C.

4. Well-B and Well-C performance results exhibit the improvement in both drilling operating cost and time. Firstly, an average rate of penetration (ROP) in Well-B and Well-C are increased by 24 and 19 percents respectively comparing to Well-A. Secondly, eliminating the tripping time and the second bit cost by drilling with a single bit trip to target depth (TD) are another accomplishment from this study. Moreover, extending bit life is also benefit the future well planning in order to reach deeper reservoir sections or extended reach drilling project.
5. RMA model provides optimum drilling parameters in order to produce maximum ROP efficiency and maintain drilling bit life. ROP scheme which is derived from simulation process can be oriented to actual field work with a good corresponding result. Besides, using the drilling RMA model with the Cost per Foot (CPF) analysis is very helpful when operator has to make a decision to tripping or continue drilling while encounter critical ROP situation.

5.2 Recommendations for The Further Study

This section provides the further study recommendations based on this study point of views and study algorithm.

1. Downhole torque measurement.

According to unavailability of downhole torque data measurement, the study constructs RMA model and SEROP scheme based on surface torque measurement. It has to be noted that surface torque and downhole torque are not exactly equal while drilling due to the energy loss along the drill string. Therefore, downhole torque measurement is recommended, if data is available, in order to obtain better accurate predicted ROP model.

2. Variable Bit Sliding Coefficient (μ) model.

Referring to the study results, Bit Sliding Coefficient (μ) value could not be exactly predicted but could be estimated in the range of 1.10 to 1.40. This is because μ is always relied on the lithology unconformity and formation complexity in each drilling area. Therefore, predicted SEROP model which is constructed and generated from variable μ value scheme with lithology adjusted will generate better accurate result.

3. Drill off test (DOT) and Leak off test (LOT).

As mentioned earlier, Drill off test provides relationship between RPM, WOB, and ROP while drilling at a certain depth in a certain area. The test also gives the best combination of drilling parameters in order to achieve optimum ROP efficiency. Moreover, DOT data can be used to calibrate the RMA model and adjust drilling parameters. Unfortunately, DOT is not often performed due to rig time consuming and data measurement accuracy.

Leak off test exhibits formation strength before breakdown and formation behaviors when applied by pressure. LOT data can be applied in model calibration process and compared to formation strength deriving from RMA model calculation. Presently, leak off test is routinely performed at the casing shoe in each section with the purpose of well control issue. Therefore, leak off test data is one of the good resources to calibrate and adjust the RMA model accuracy.

4. Real Time or Well site RMA operator.

Occasionally, WOB and RPM need to be operated out of recommendation range due to the hole directional concerning and bit walk tendency problem. Therefore, well-site RMA operator is highly recommended to simulate model based on current operation dictate at the well site.

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APPENDICES

APPENDIX A
WELL-A RMA MODEL

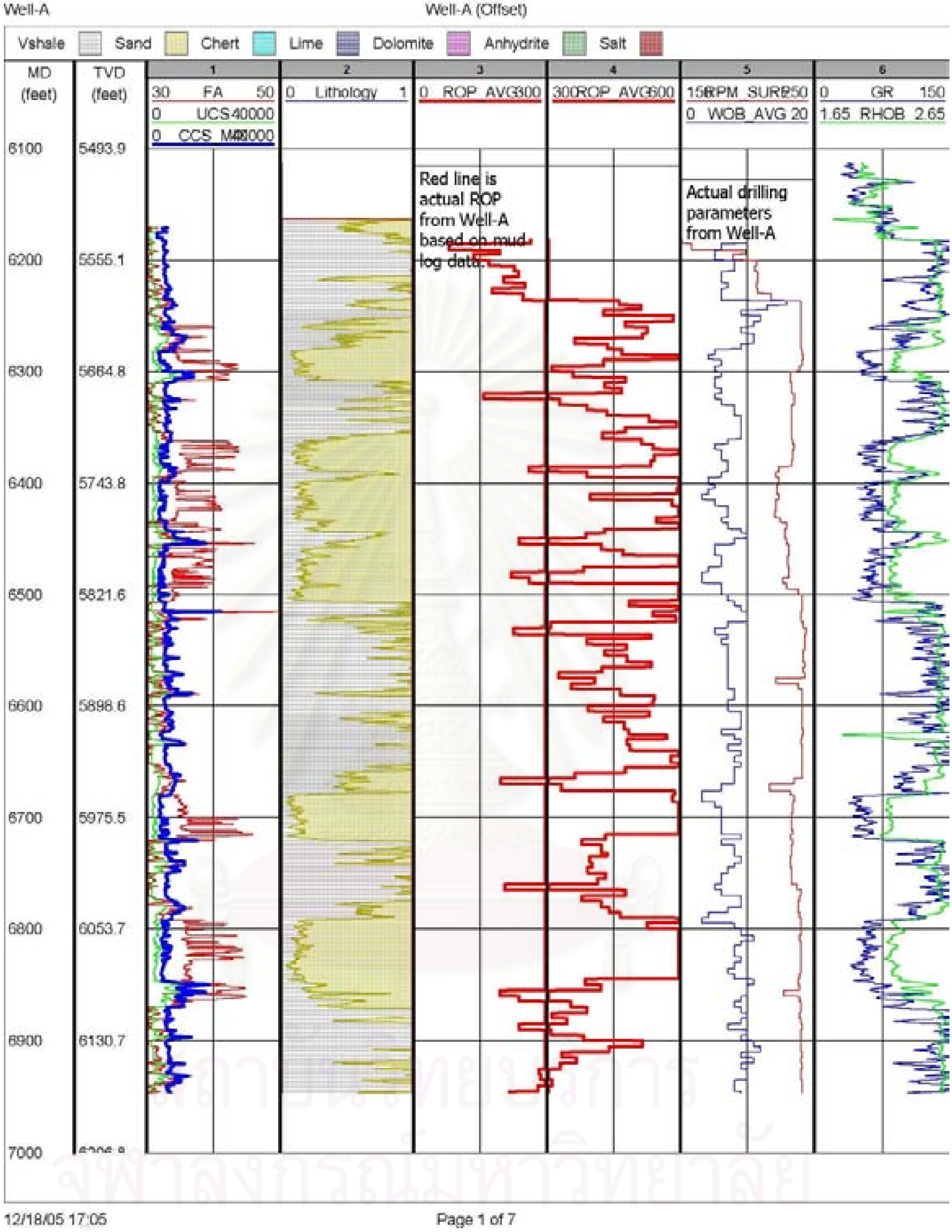


Figure A: Well-A RMA model from 6,100 to 7,000 ft MD.

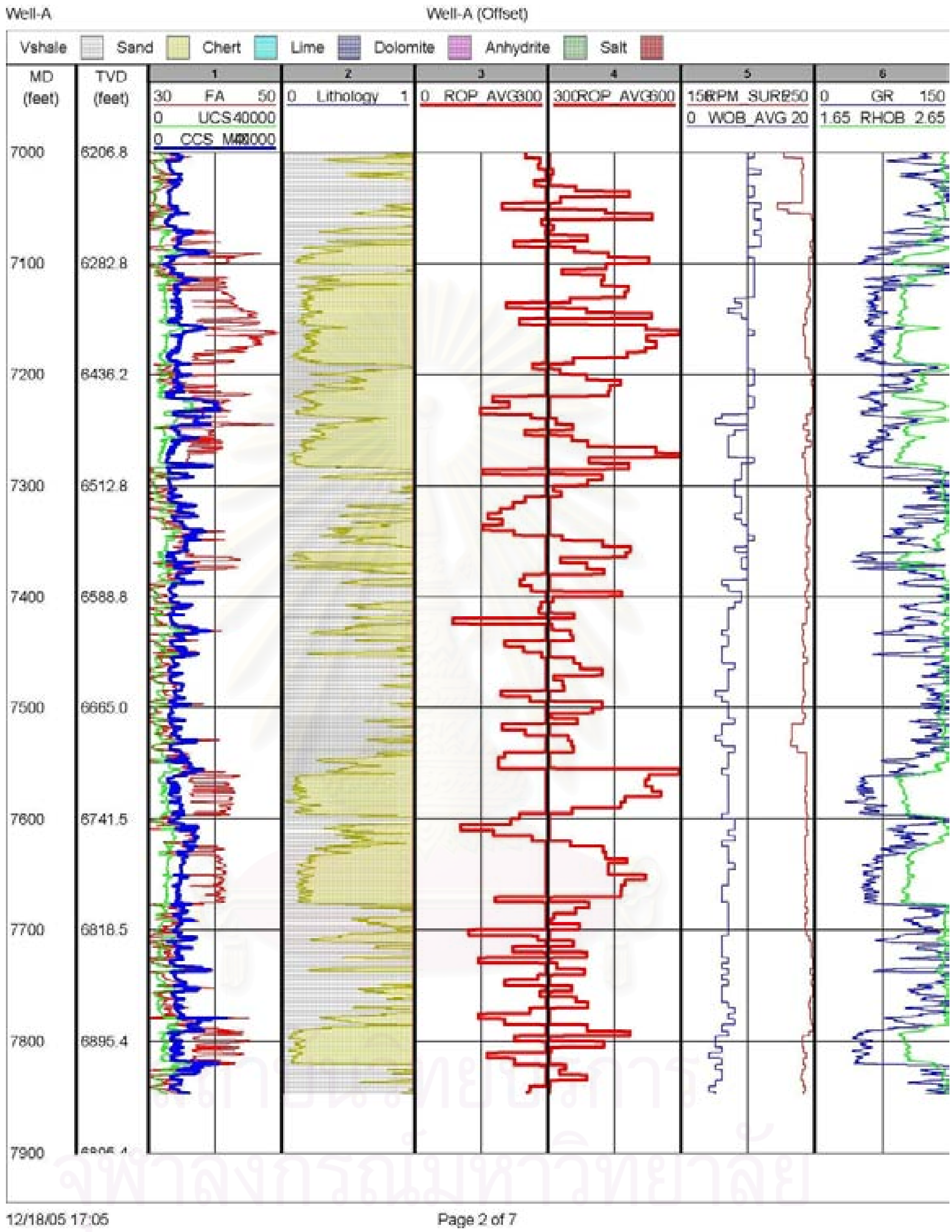


Figure A: Well-A RMA model from 7,000 to 7,900 ft MD.

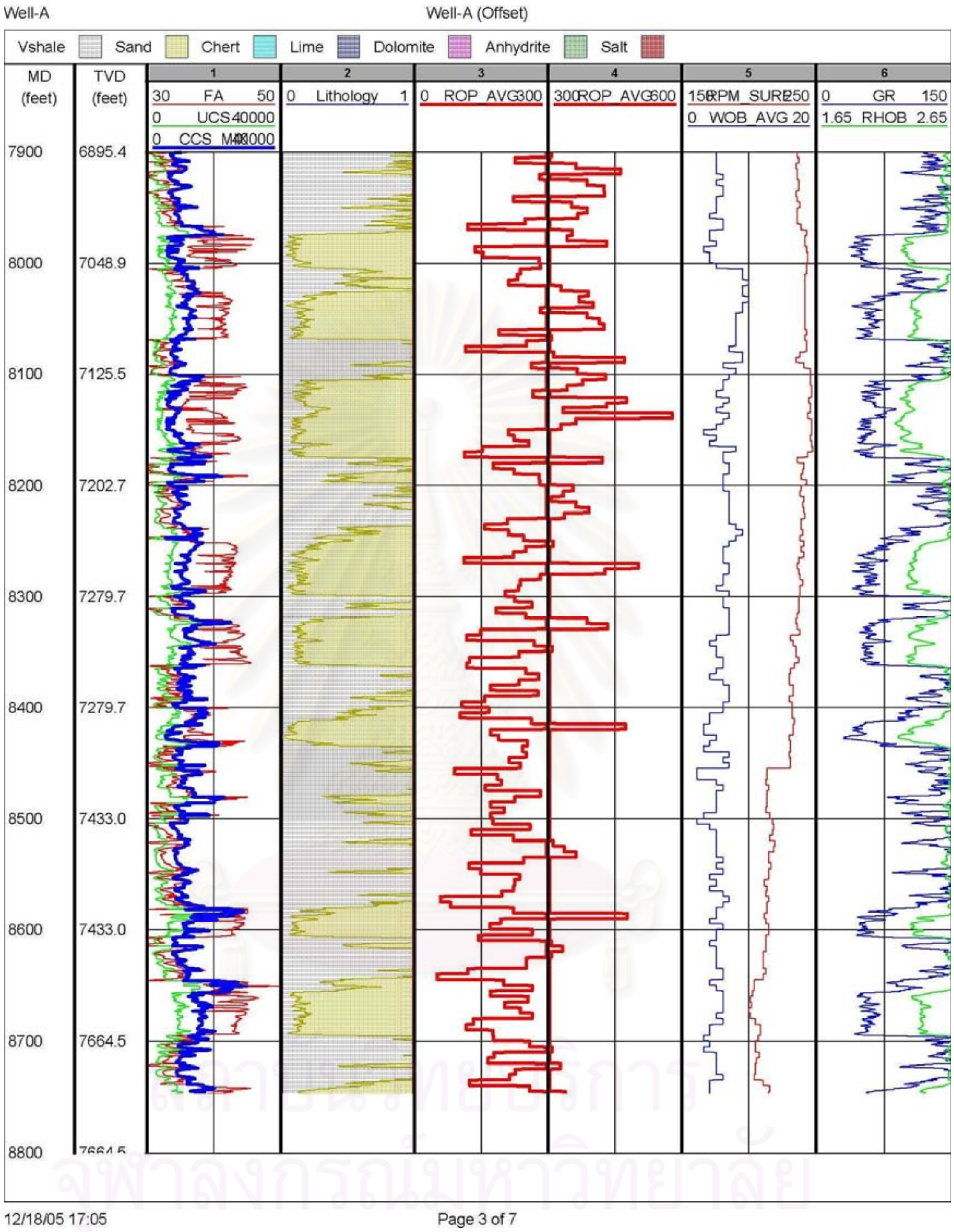


Figure A: Well-A RMA model from 7,900 to 8,800 ft MD.

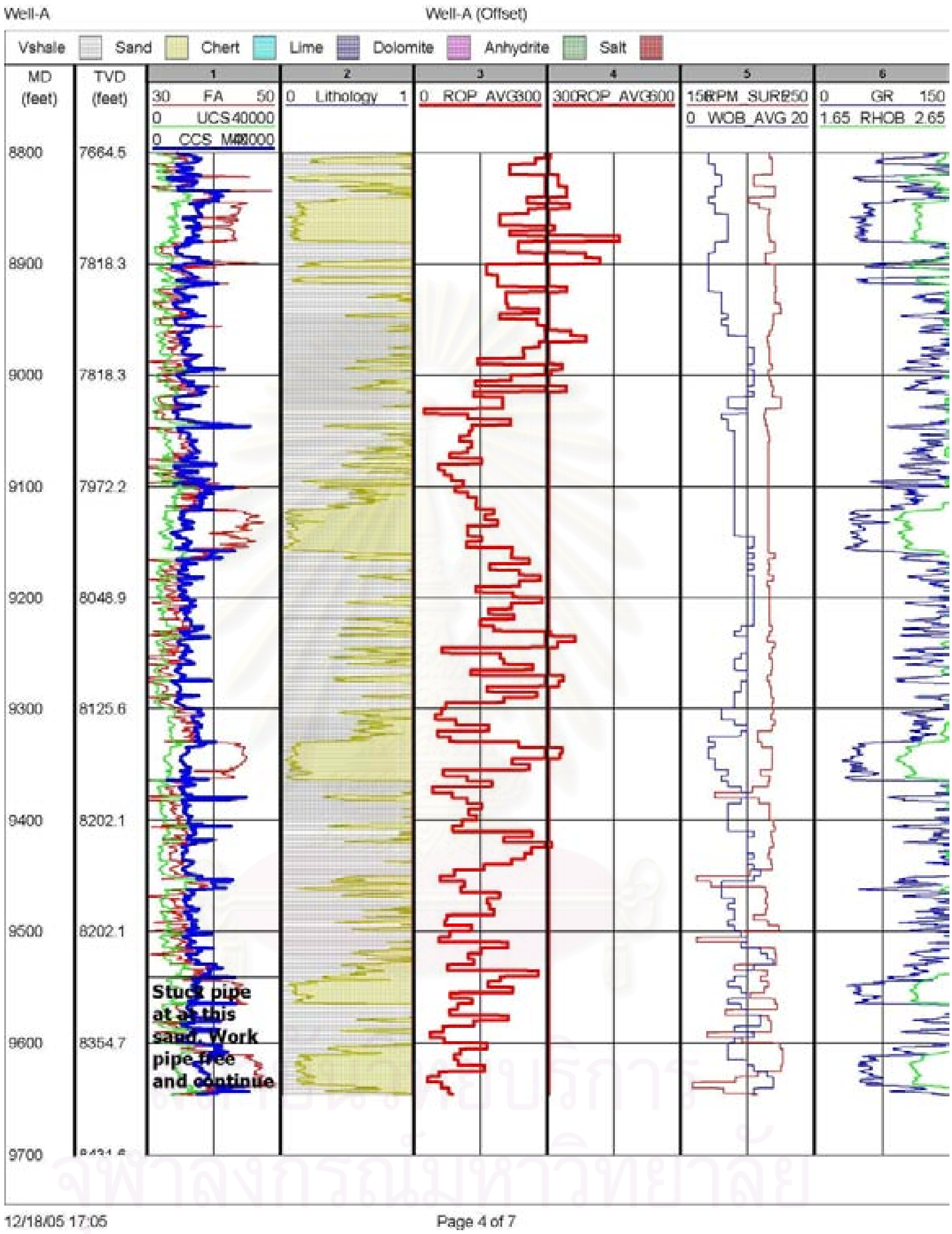


Figure A: Well-A RMA model from 8,800 to 9,700 ft MD.

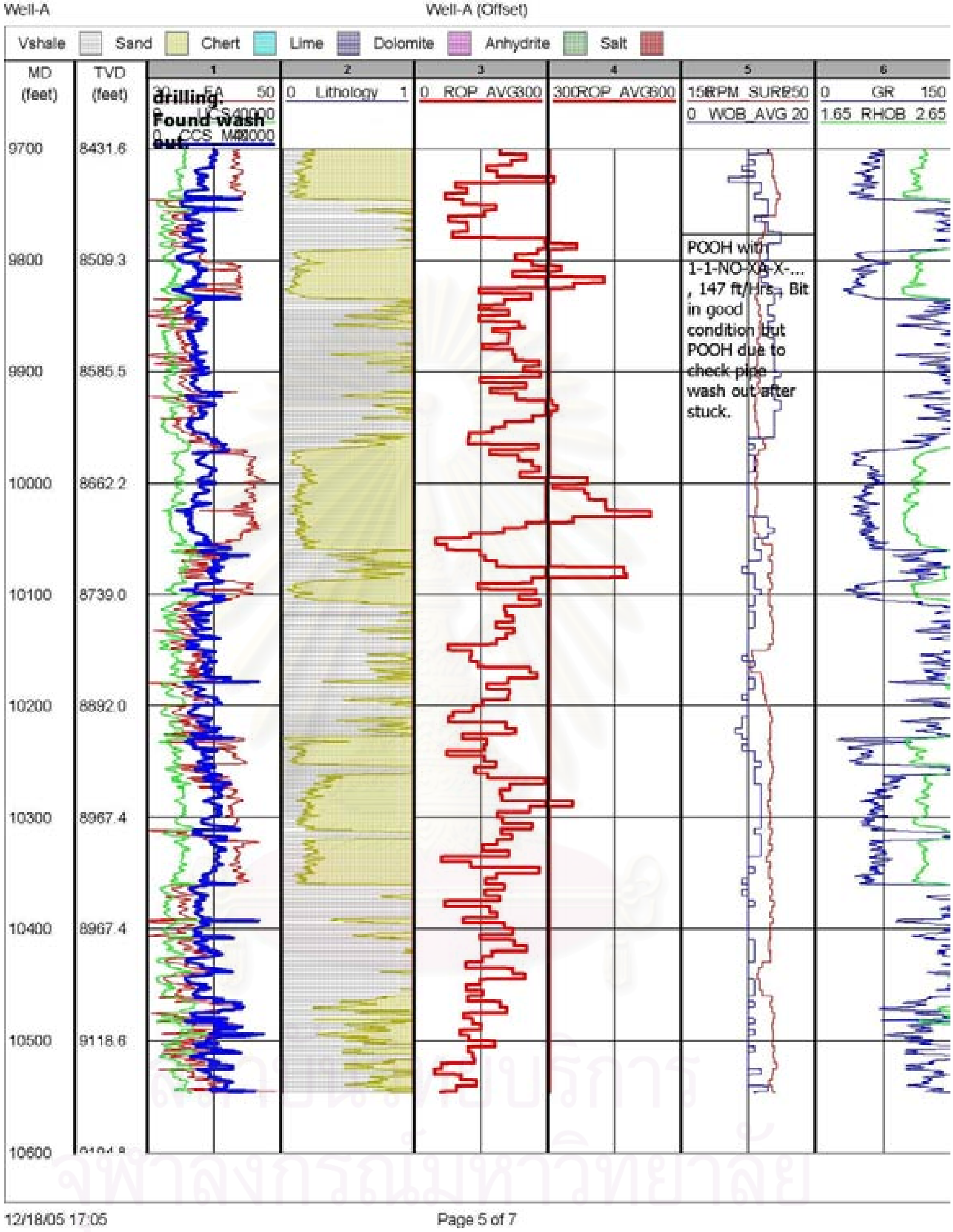


Figure A: Well-A RMA model from 9,700 to 10,600 ft MD.

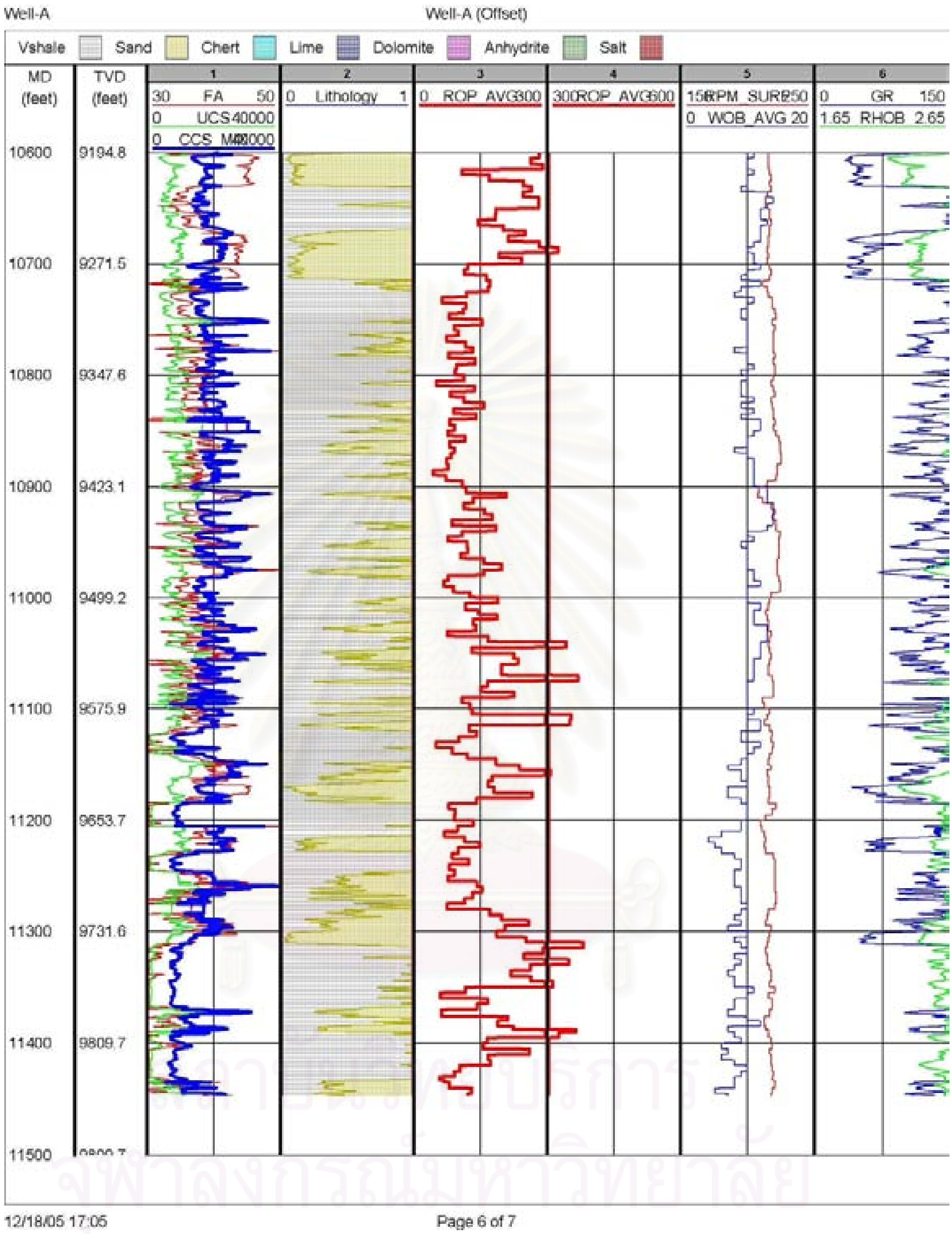


Figure A: Well-A RMA model from 10,600 to 11,500 ft MD.

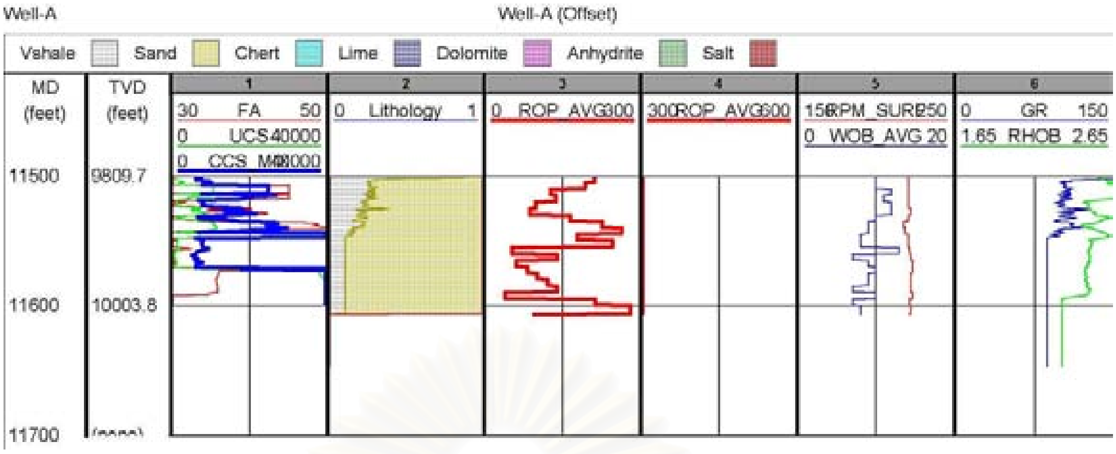


Figure A: Well-A RMA model from 11,500 to 11,600 ft MD.

APPENDIX B

SIMULATED RMA MODEL WITH μ = 1.45

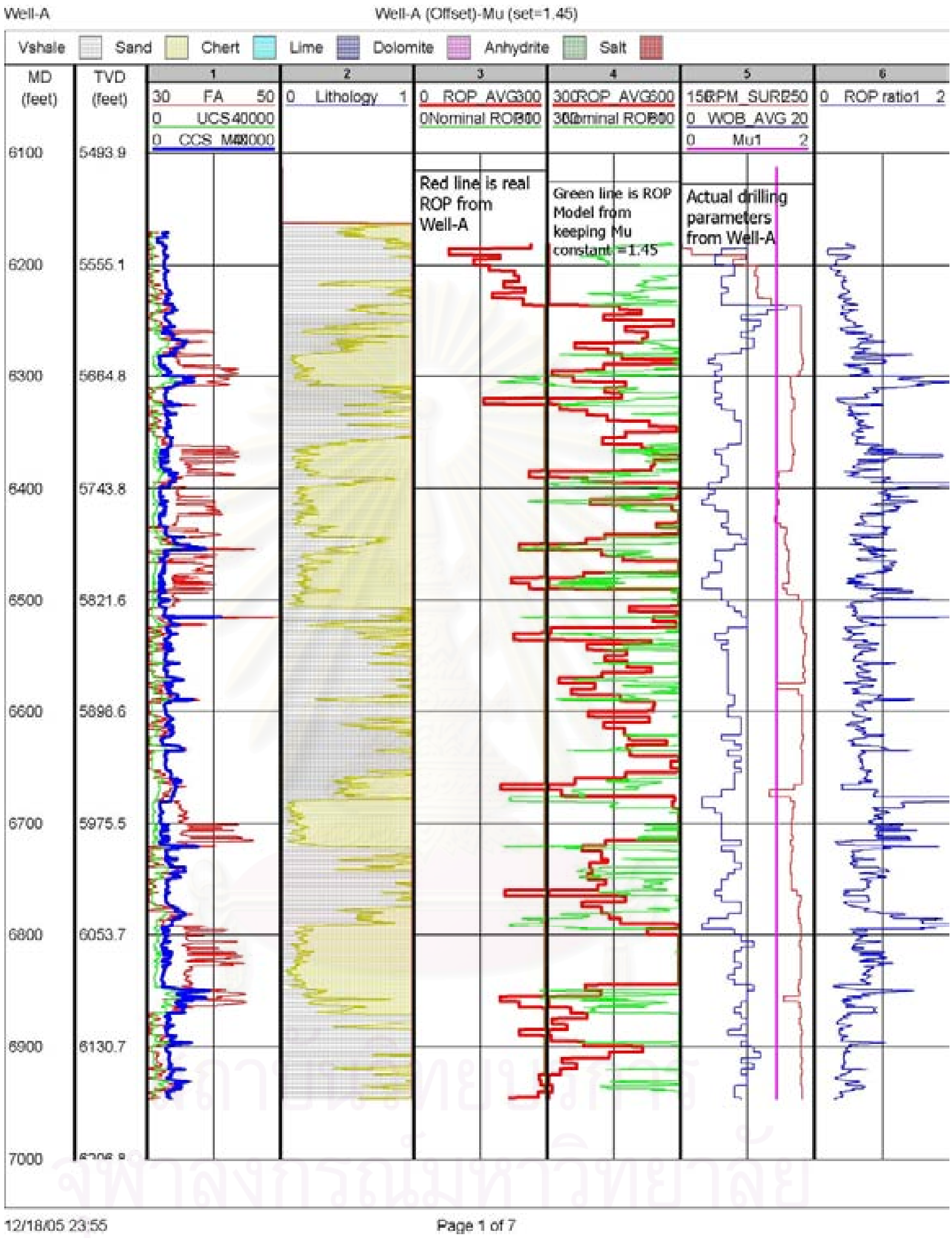


Figure B: Simulated ROP with Actual ROP plots with μ setting = 1.45 from depth 6,100 ft md to 7,000 ft md.

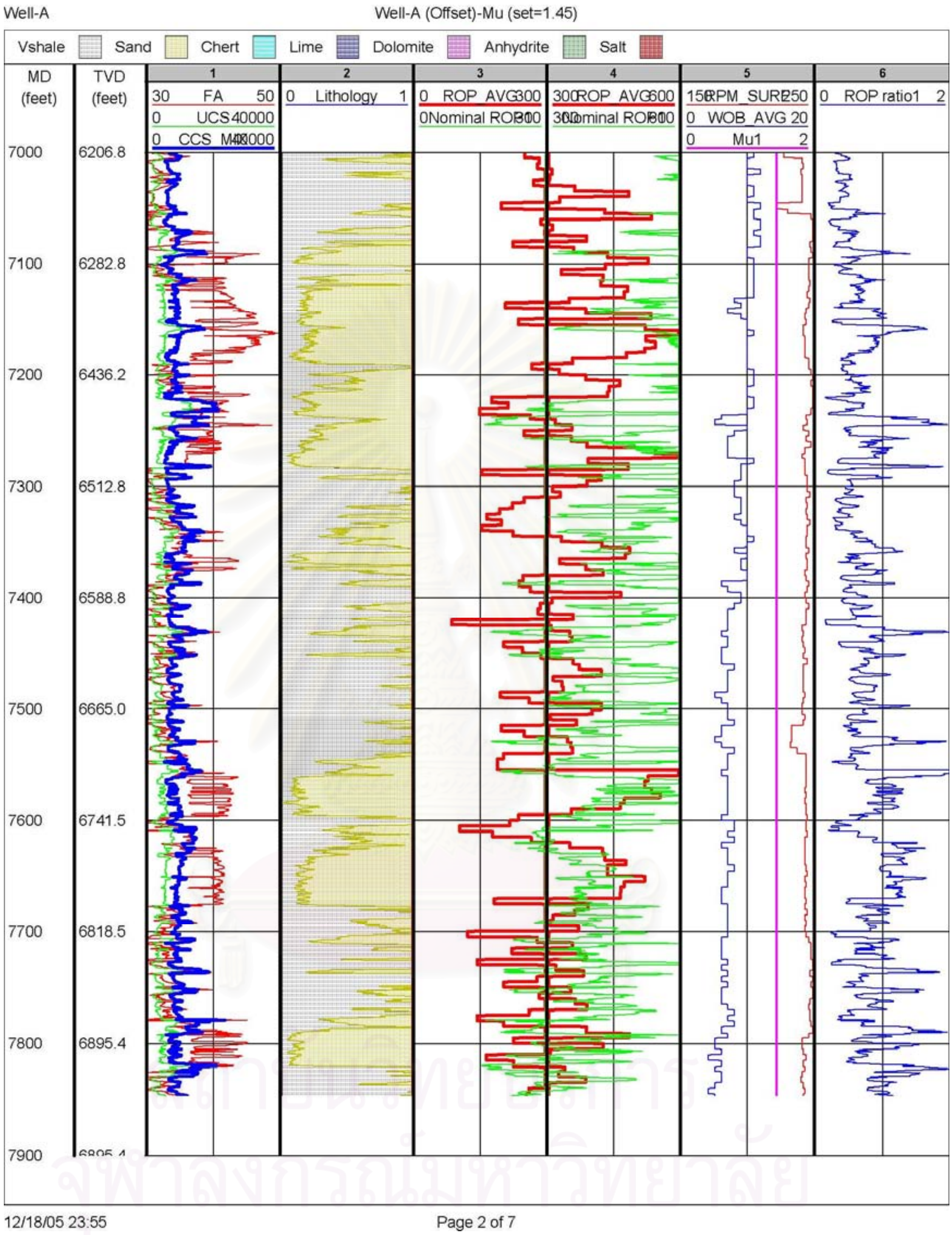


Figure B: Simulated ROP with Actual ROP plots with μ setting = 1.45 from depth 7,000 ft md to 7,900 ft md.

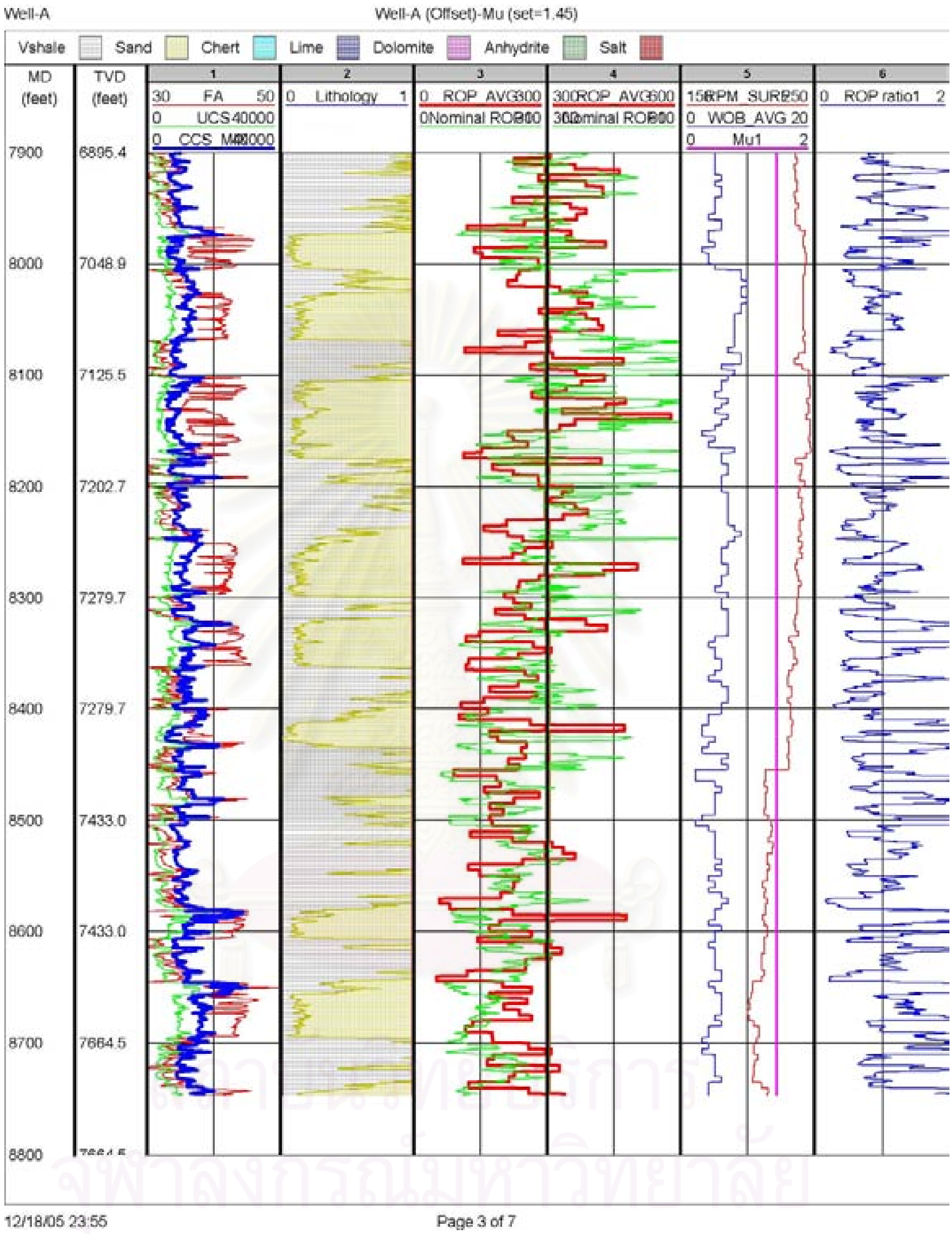


Figure B: Simulated ROP with Actual ROP plots with μ setting = 1.45 from depth 7,900 ft md to 8,800 ft md.

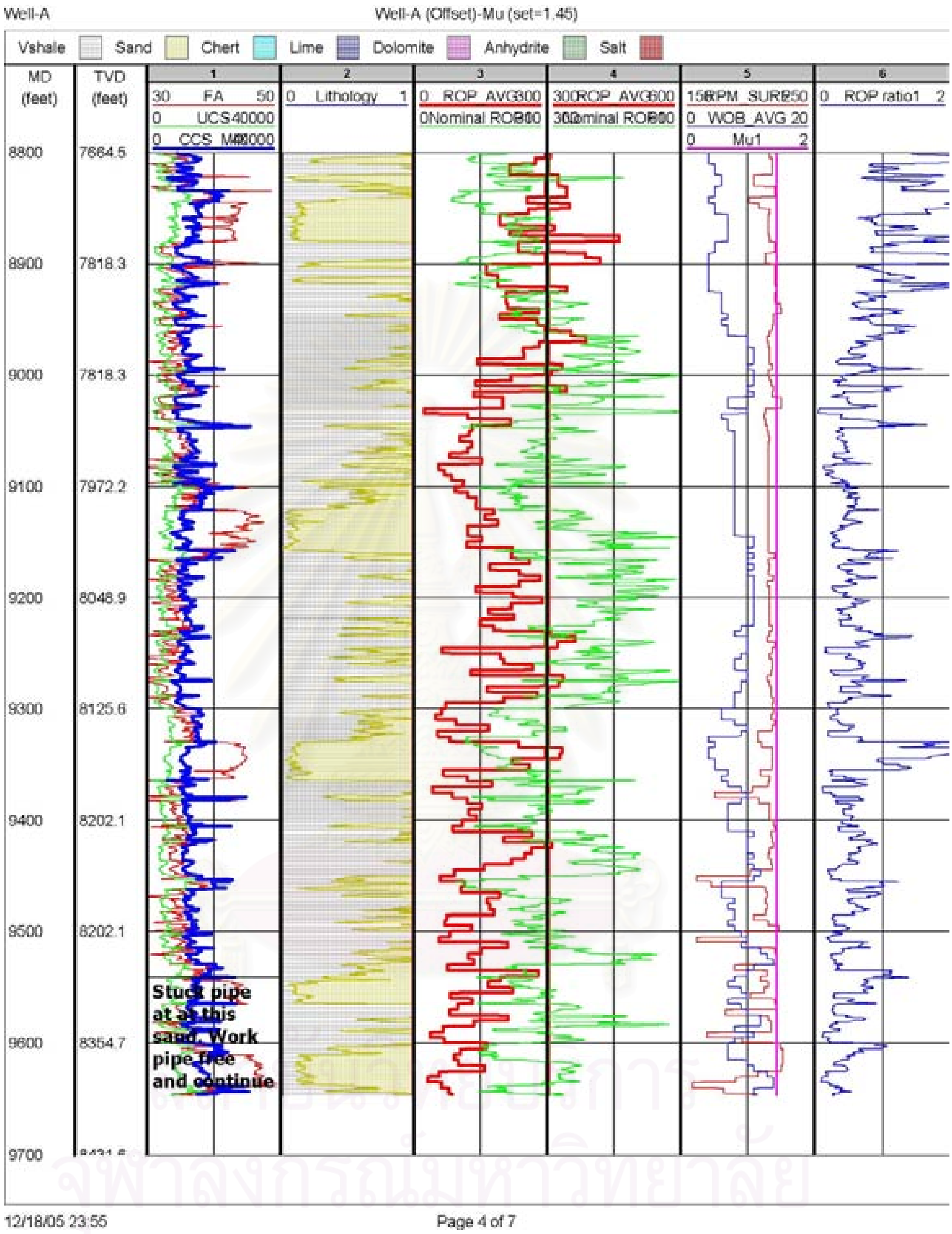


Figure B: Simulated ROP with Actual ROP plots with μ setting = 1.45 from depth 8,800 ft md to 9,700 ft md.

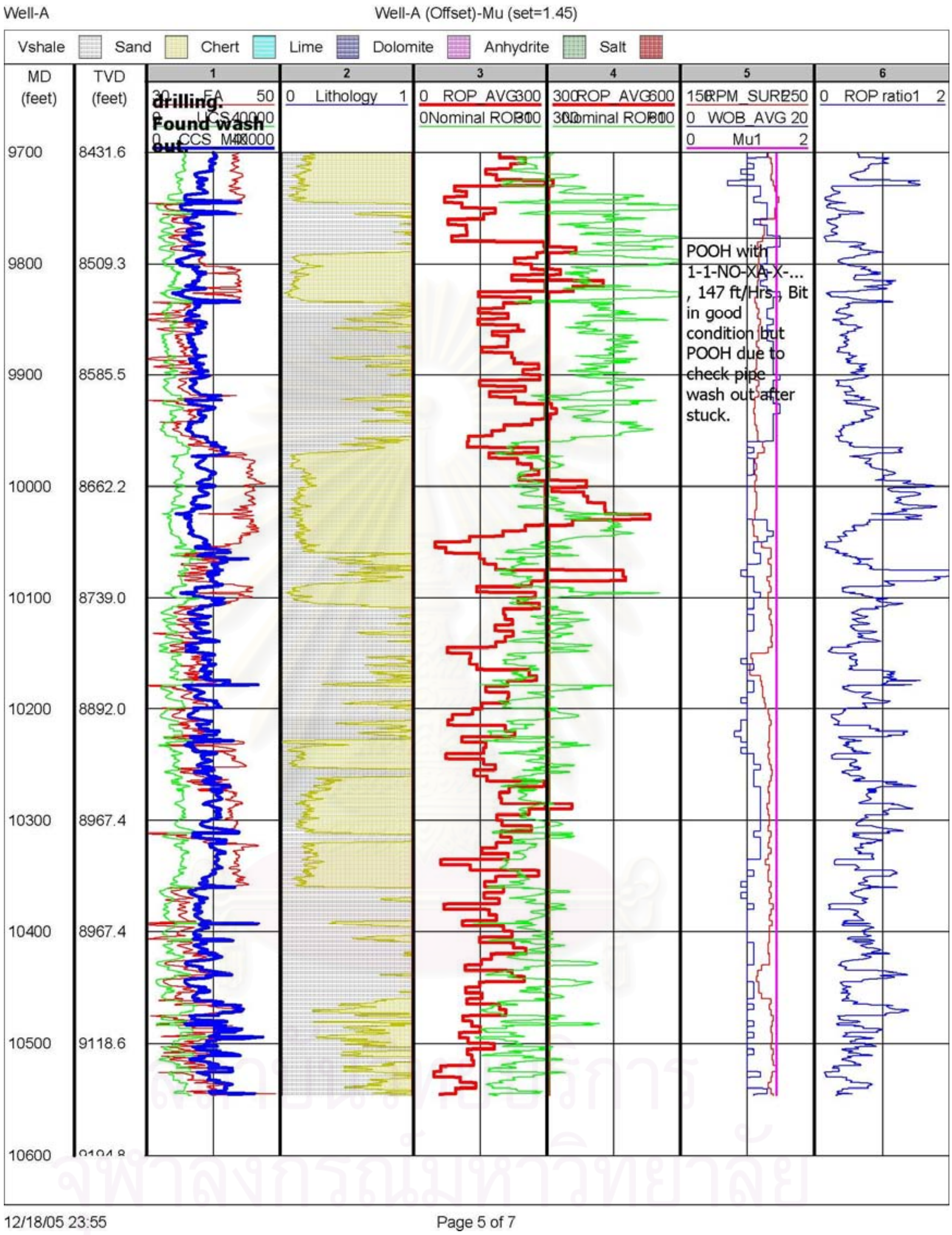


Figure B: Simulated ROP with Actual ROP plots with μ setting = 1.45 from depth 9,700 ft md to 10,600 ft md.

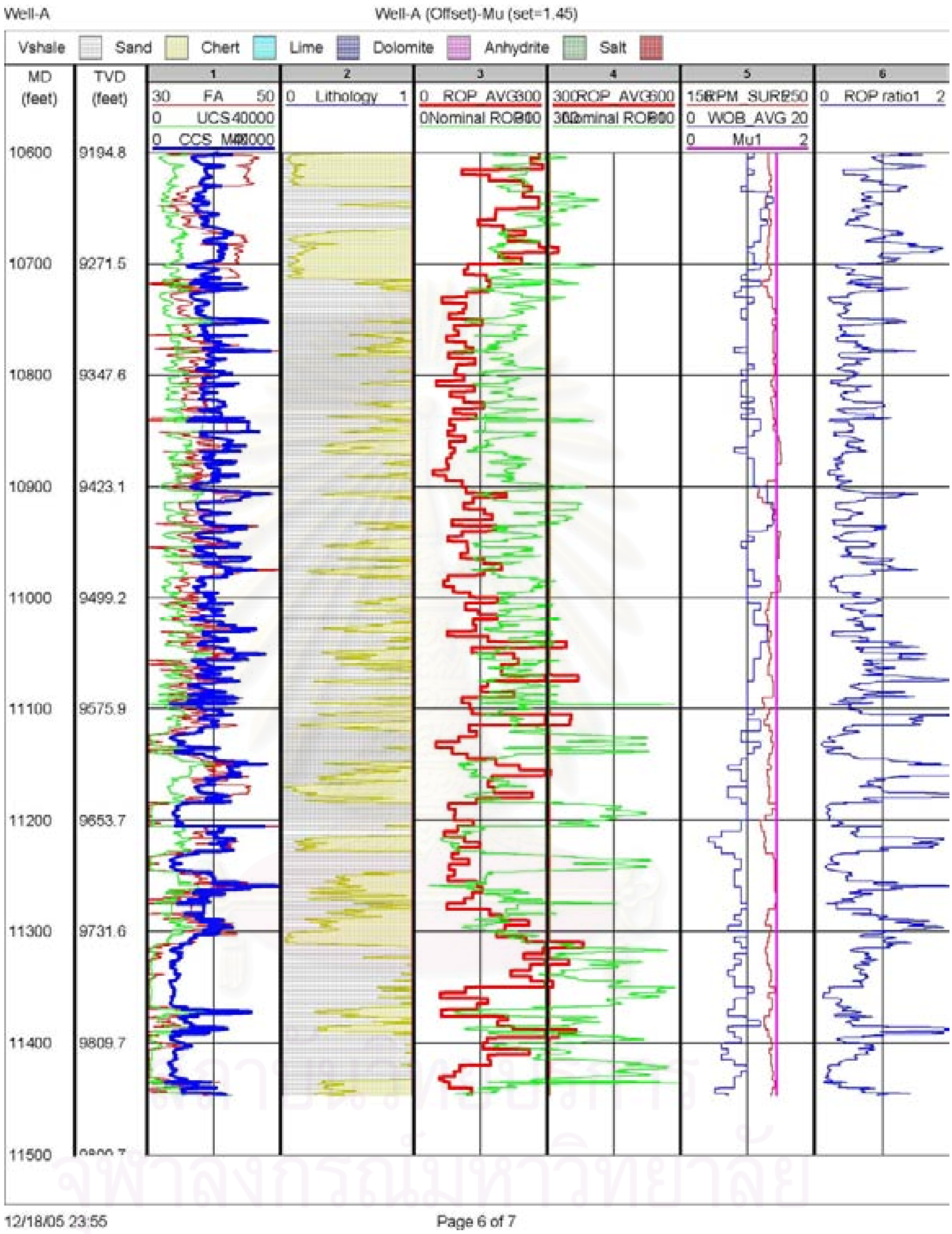


Figure B: Simulated ROP with Actual ROP plots with μ setting = 1.45 from depth 10,600 ft md to 11,500 ft md.

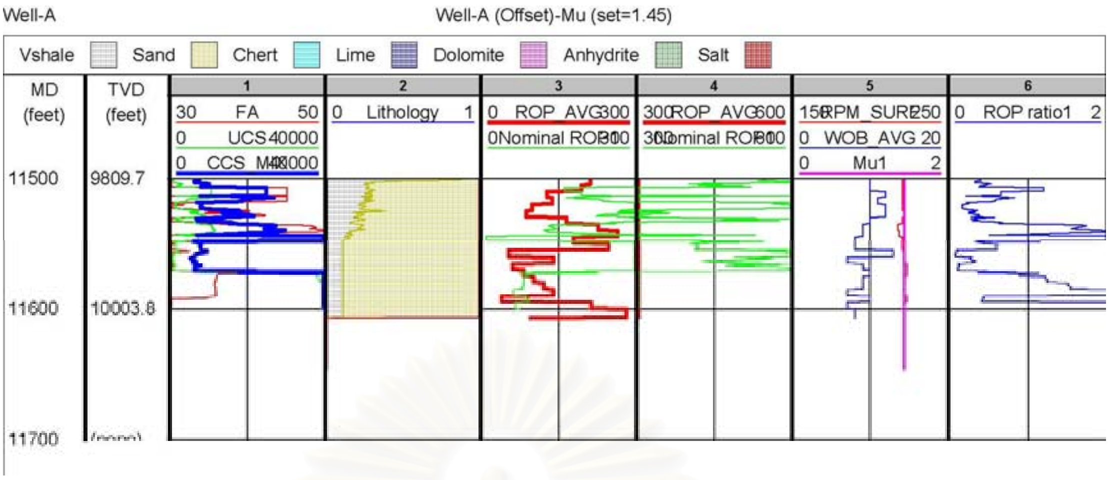


Figure B: Simulated ROP with Actual ROP plots with μ setting = 1.45 from depth 11,500 ft md to 11,700 ft md.

APPENDIX C
WELL-B RMA MODEL WITH OPTIMIZATION DRILLING PARAMETERS

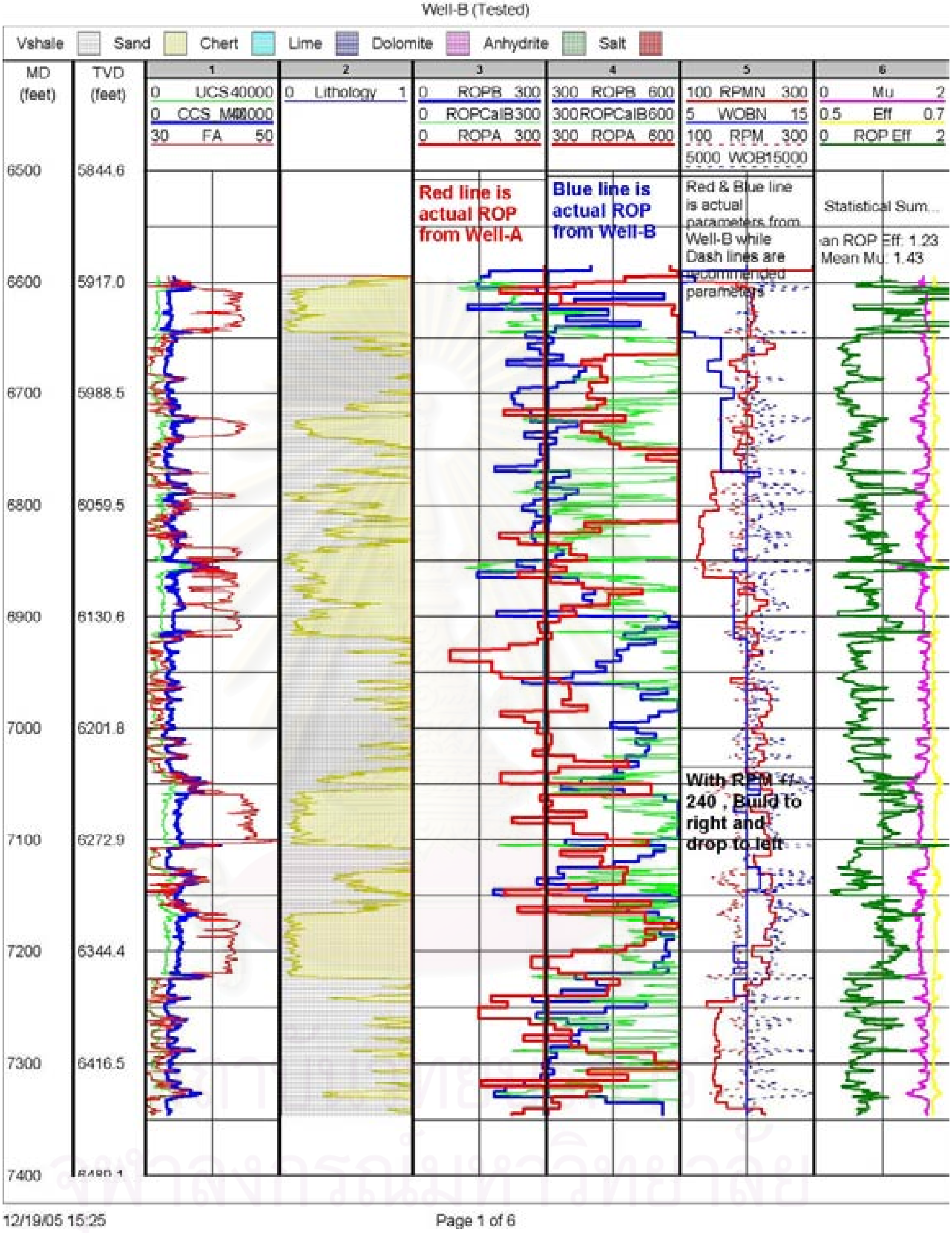


Figure C: Well-B RMA model from depth 6,500 to 7,400 ft MD.

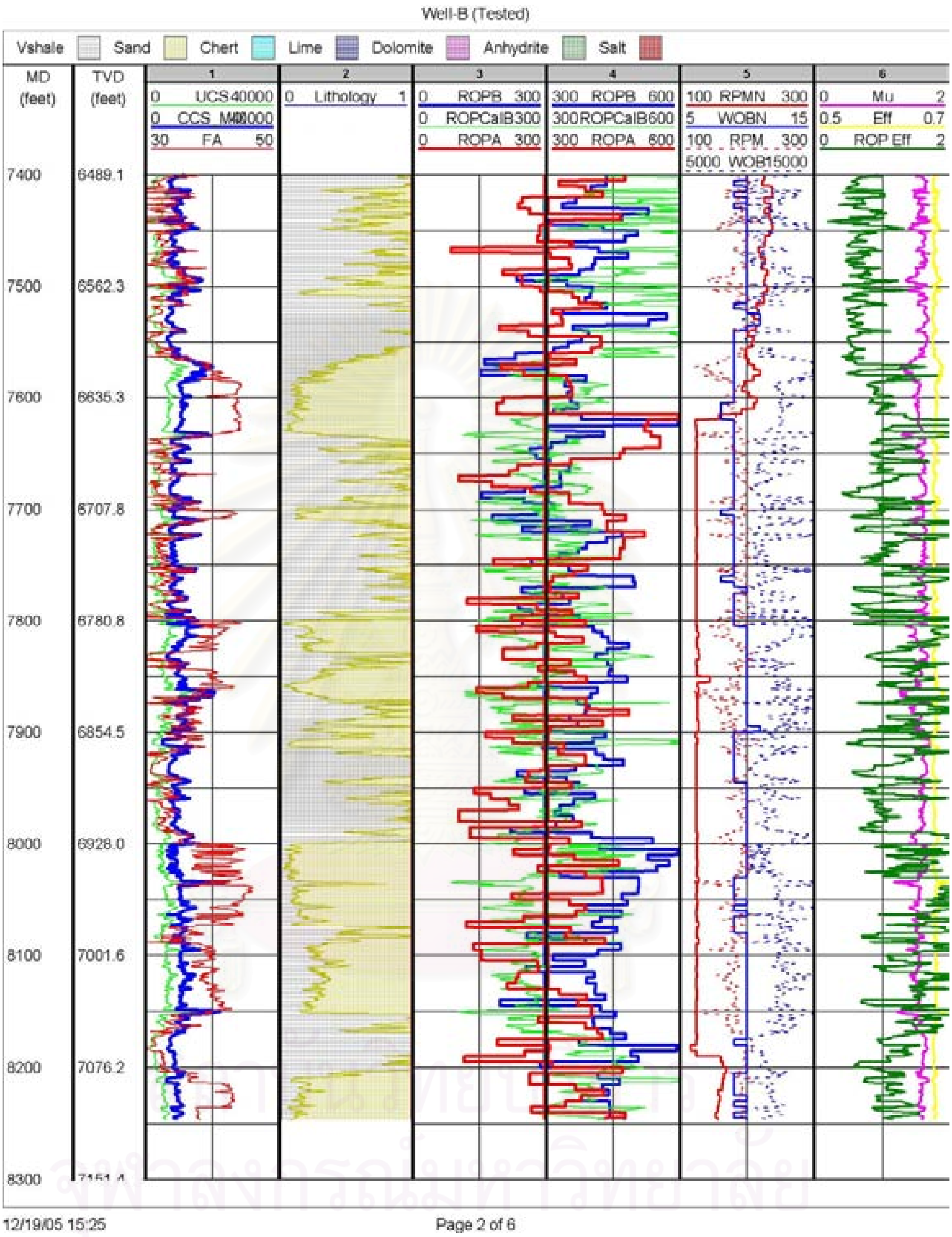


Figure C: Well-B RMA model from depth 7,400 to 8,300 ft MD.

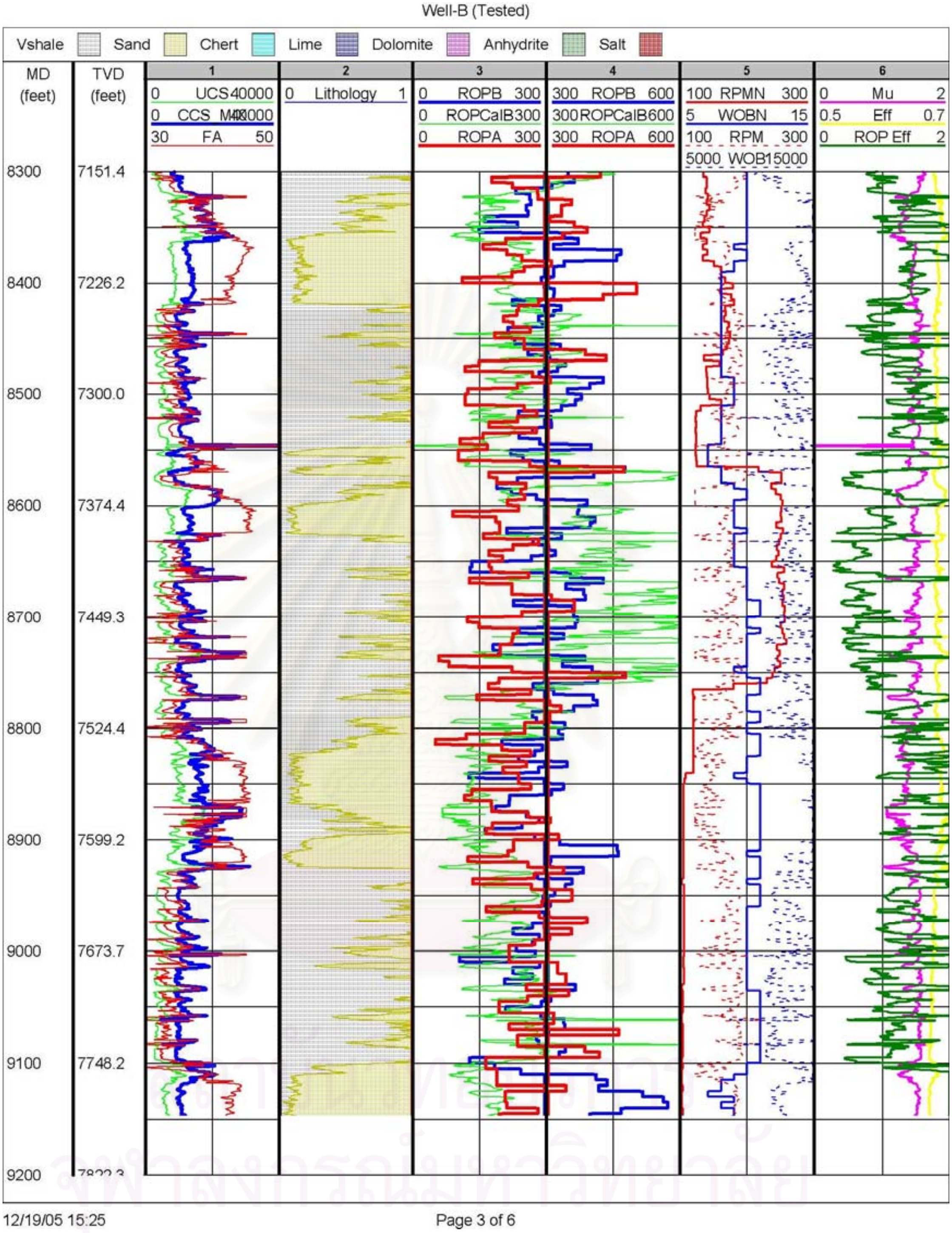


Figure C: Well-B RMA model from depth 8,300 to 9,200 ft MD.

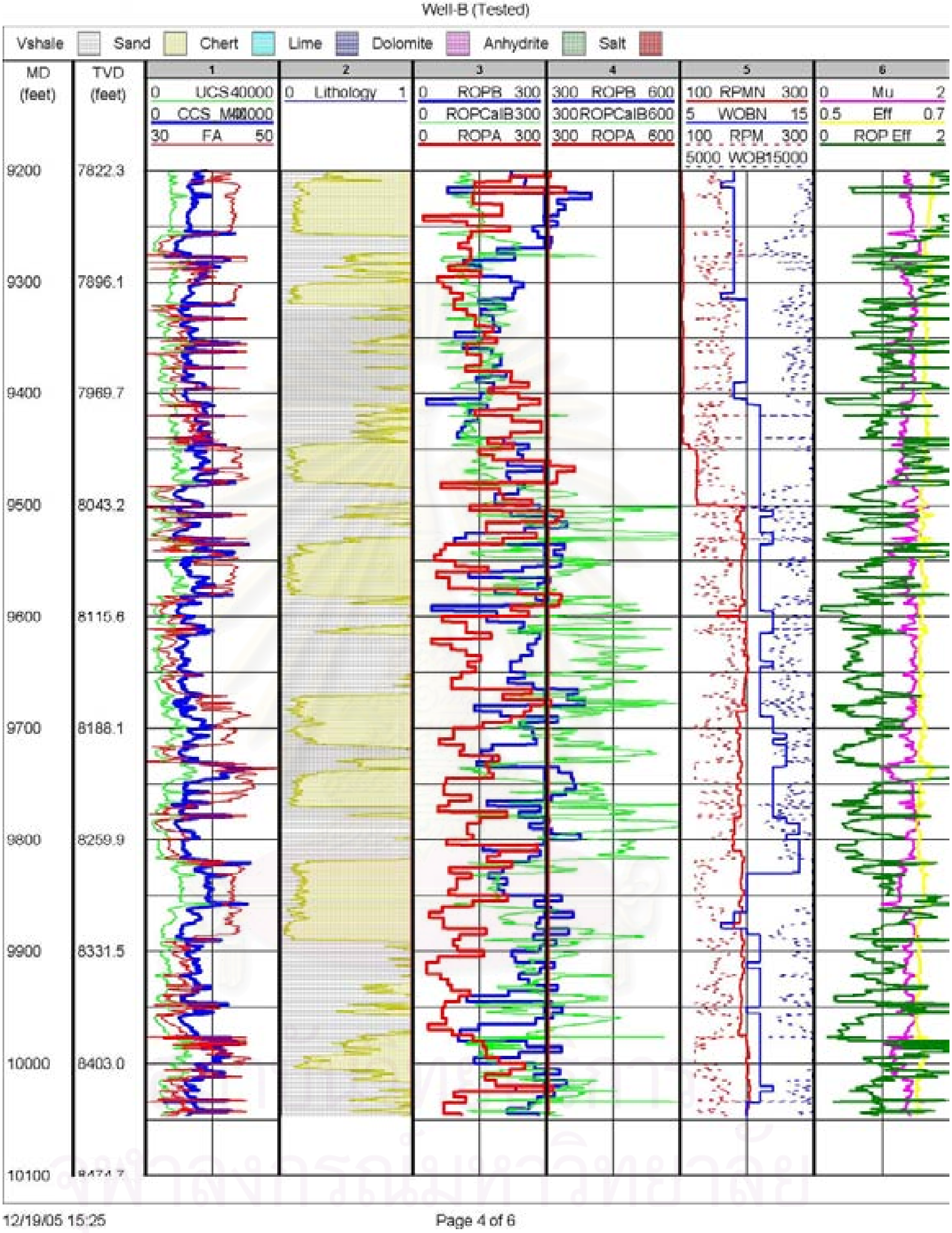


Figure C: Well-B RMA model from depth 9,200 to 10,100 ft MD.

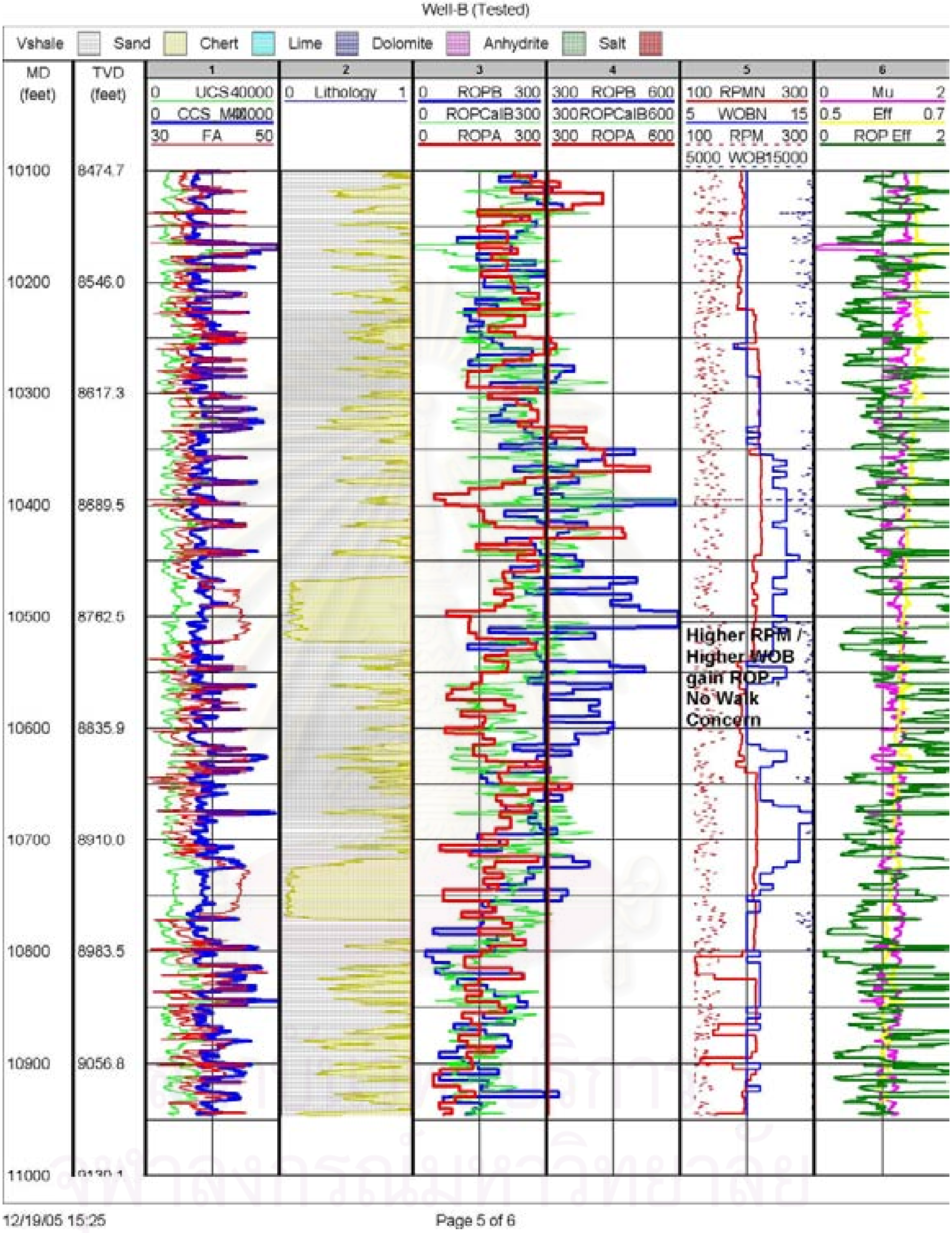


Figure C: Well-B RMA model from depth 10,100 to 11,00 ft MD.

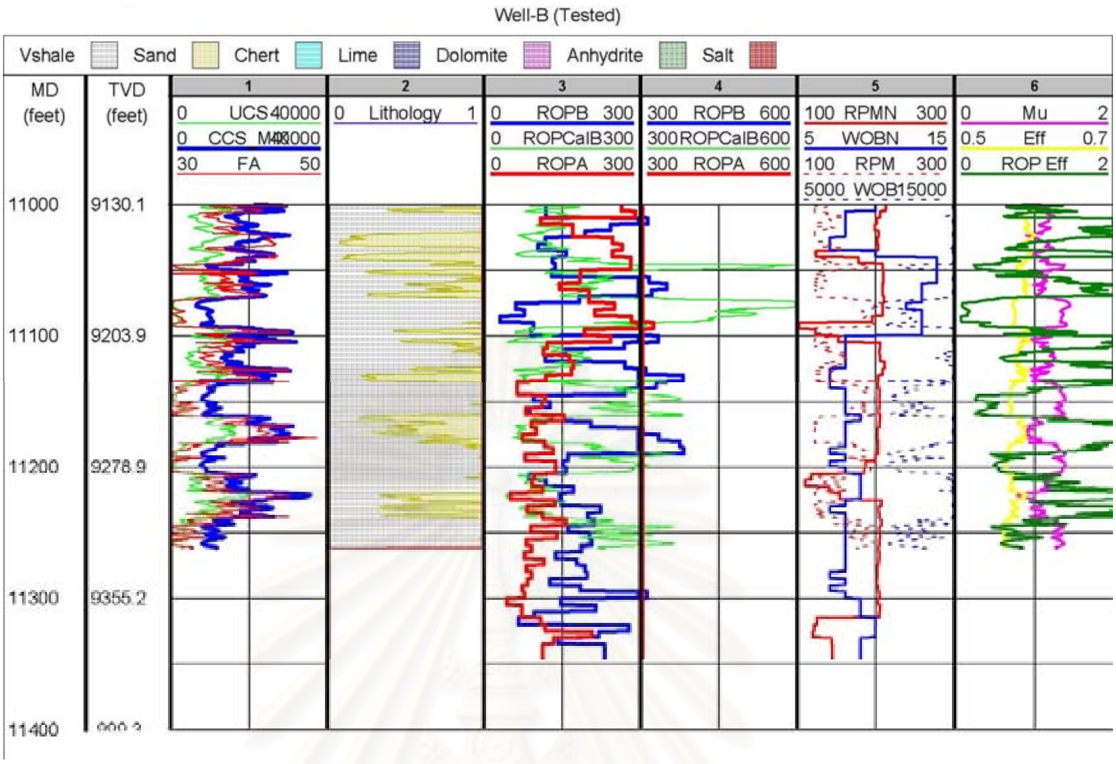
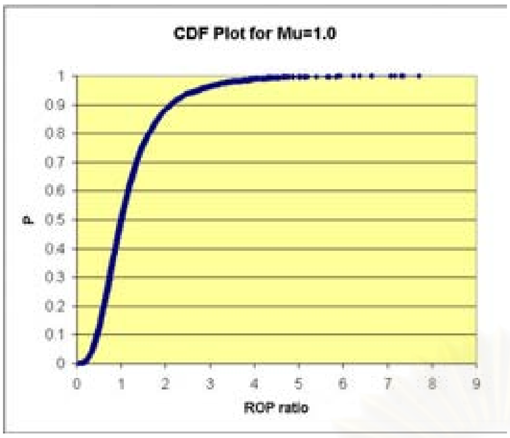
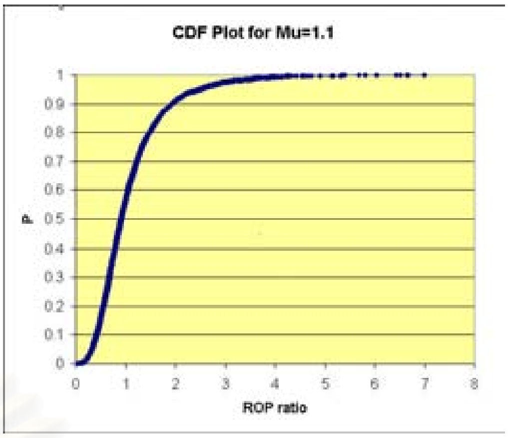


Figure C: Well-B RMA model from depth 11,000 to 11,300 ft MD.

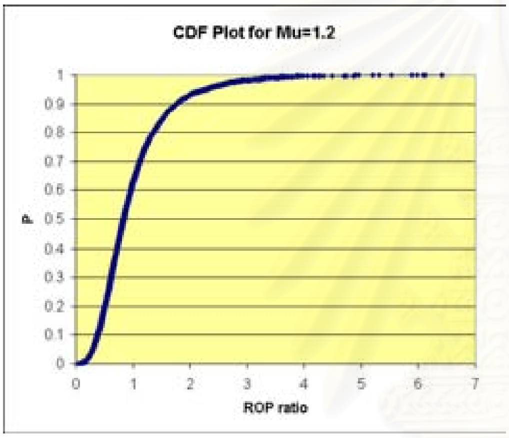
APPENDIX D
CUMULATIVE DISTRIBUTION FUNCTION (CDF) PLOTS AT VARIABLE μ



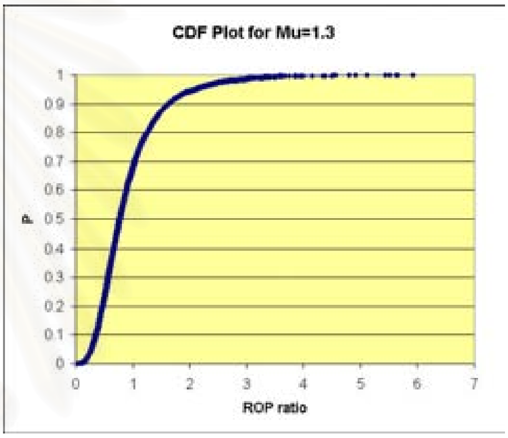
CDF plot for Mu = 1.0



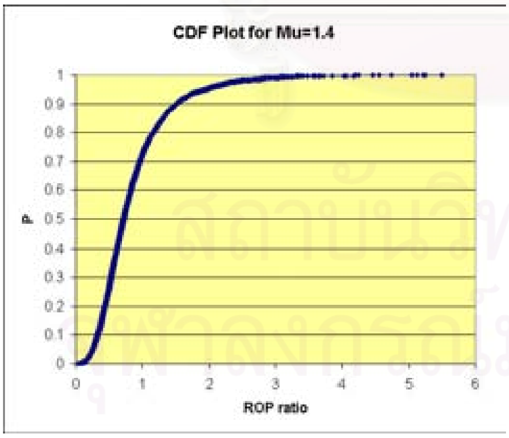
CDF plot for Mu = 1.1



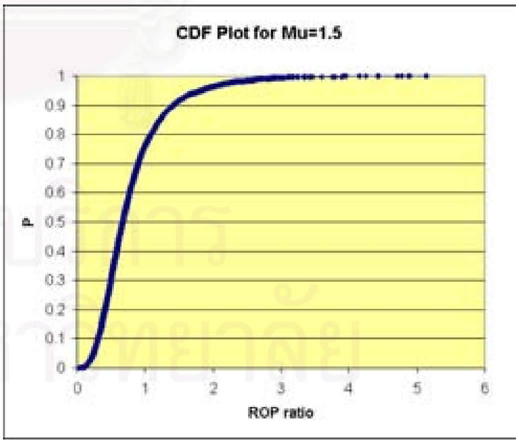
CDF plot for Mu = 1.2



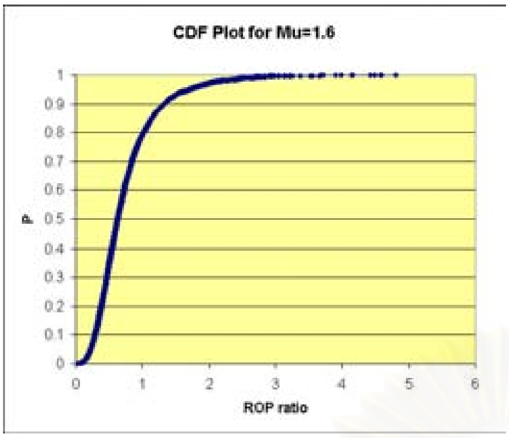
CDF plot for Mu = 1.3



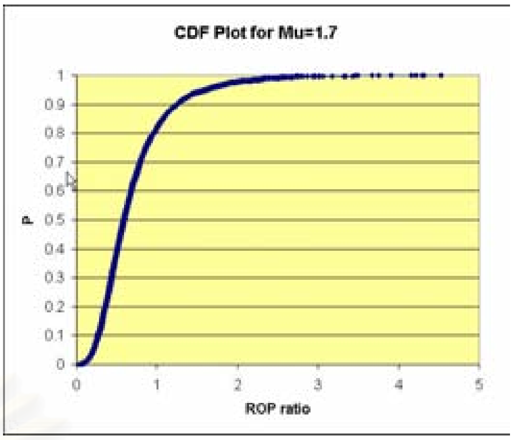
CDF plot for Mu = 1.4



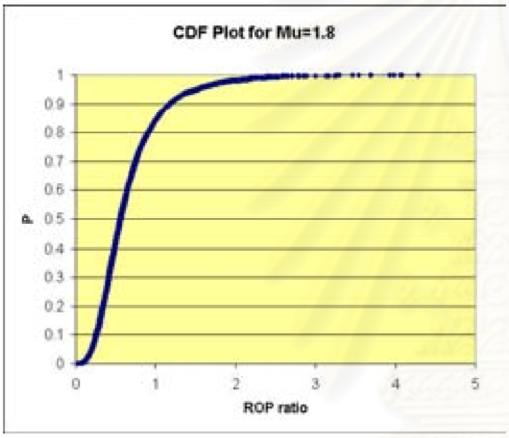
CDF plot for Mu = 1.5



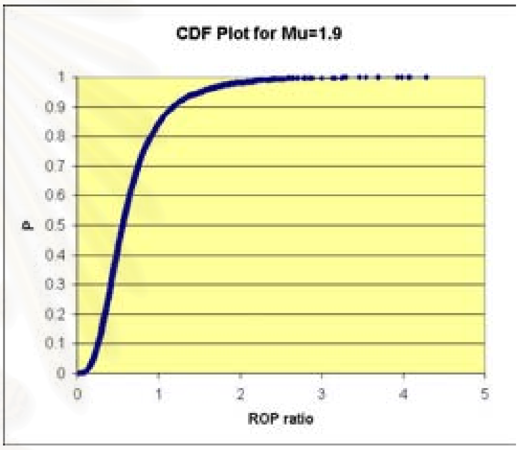
CDF plot for Mu = 1.6



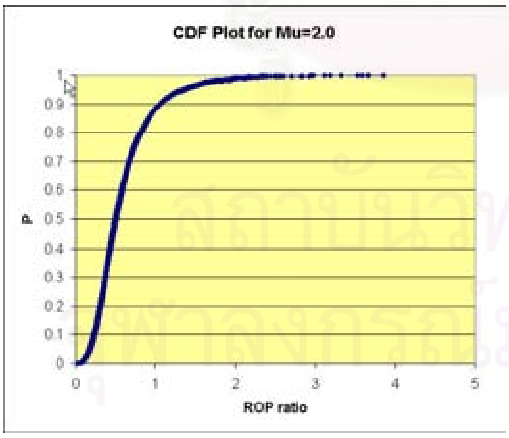
CDF plot for Mu = 1.7



CDF plot for Mu = 1.8



CDF plot for Mu = 1.9



CDF plot for Mu = 2.0

APPENDIX E

WELL-C RMA REGENERATED MODEL

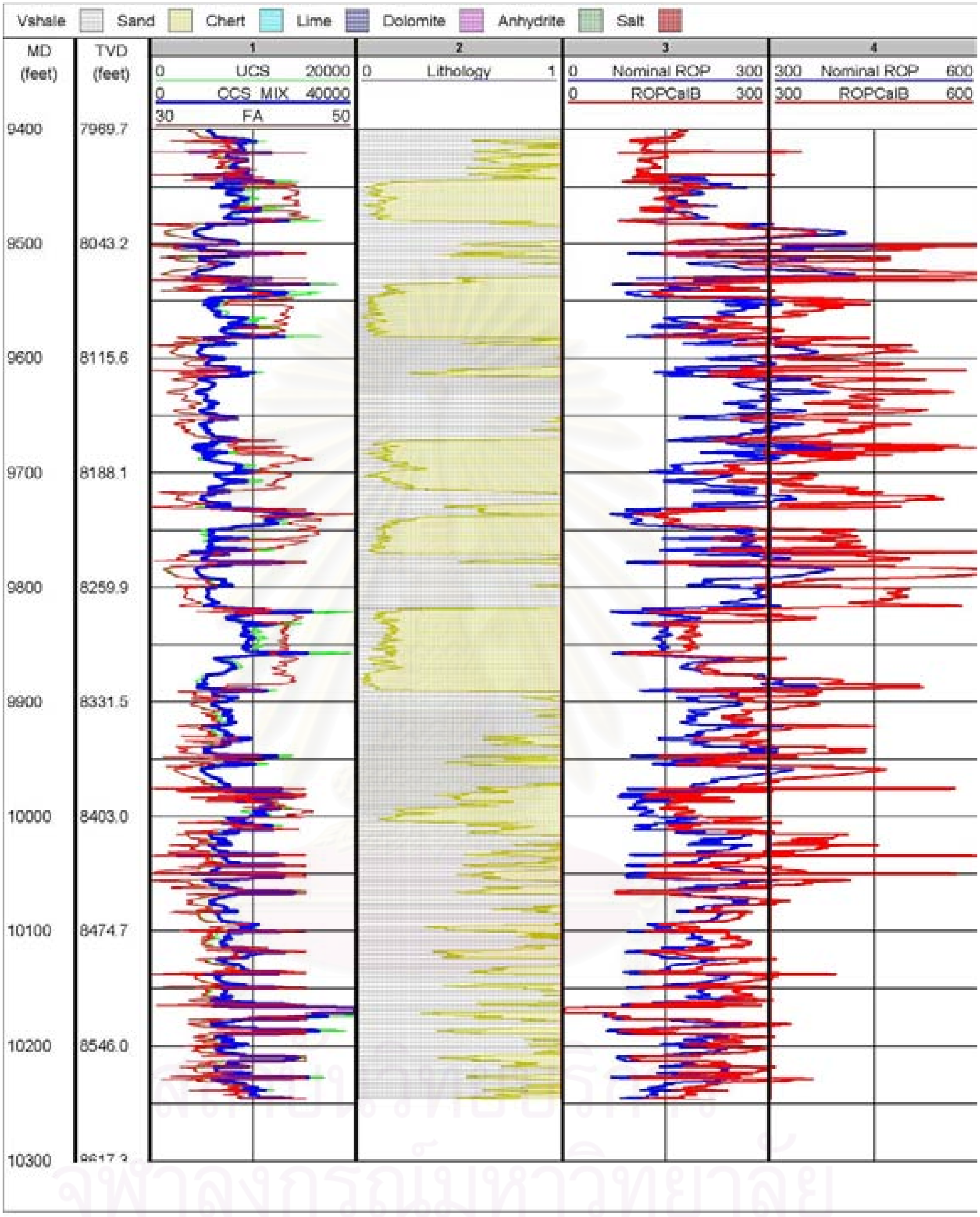


Figure D: Regenerated RMA model from depth 9,400 to 10,300 ft MD.

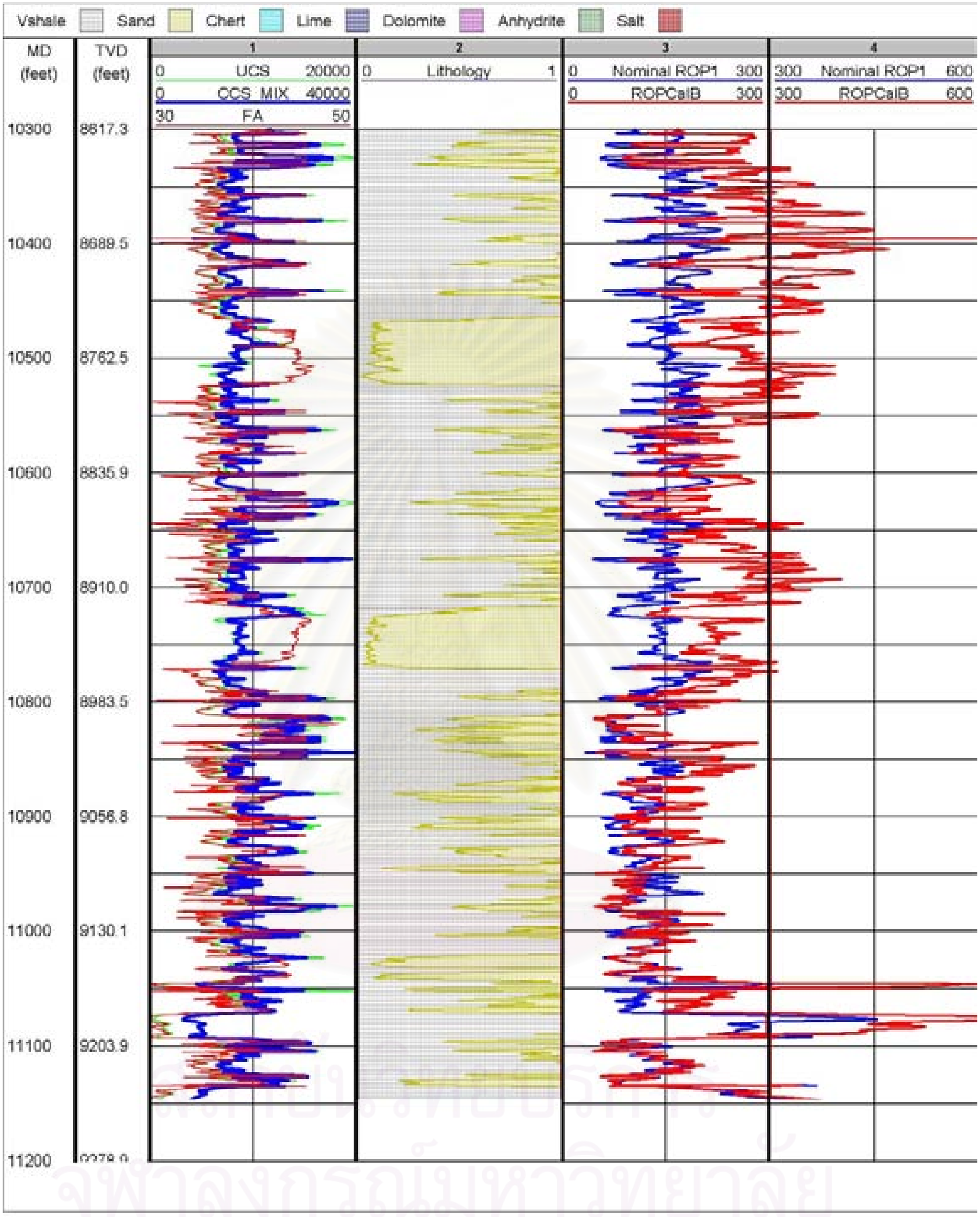


Figure D: Regenerated RMA model from depth 10,300 to 11,200 ft MD.

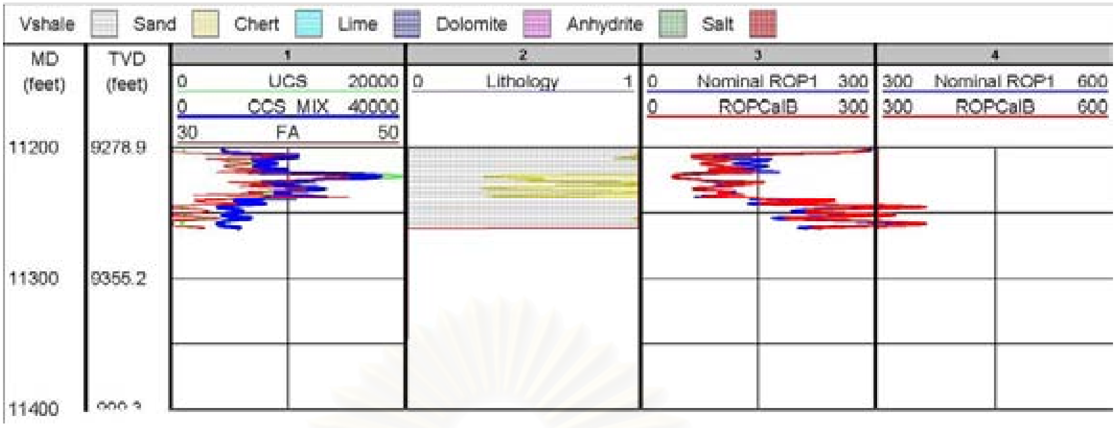


Figure D: Regenerated RMA model from depth 11,200 to 11,300 ft MD.

Vitae

Chatwit Pochan was born on November 15, 1978 in Narathivas province, Thailand. He received his B.Eng. in Civil Engineering from the Faculty of Engineering, Chiangmai University in 2000. He has been a graduate student in the Master's Degree Program in Petroleum Engineering of the Department of Mining and Petroleum Engineering, Chulalongkorn University since 2003. Currently, he works as a drilling engineer at Chevron Offshore (Thailand) Limited.