CERTIFICATION OF APPROVAL

Oil Well Drilling Planning for Vertical Drilling (Manual)

by

Ron Fernandez Sandanasamy

A project dissertation submitted to the

Petroleum Engineering Programme

Universiti Teknologi PETRONAS

in partial fulfillment of the requirements for the

BACHELOR OF ENGINEERING (Hons)

(PETROLEUM ENGINEERING)

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TRONOH, PERAK

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken by unspecified sources or persons.

RON FERNANDEZ SANDANASAMY

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ABSTRACT

Drilling planning is the key to being able to safely and economically drill a usable hole for oil and gas production. The economic feasibility of drilling a well is established from cost estimation of drilling, completion, and production operations, while safety and cost control are achieved through the proper planning of all relevant programs that have an impact on the proposed prospect well. Planning for drilling an oil well requires many detailed studies evaluating every aspect that directly or indirectly influences the successful economic outcome of the project. Planning requires intuitive, common sense judgments controlling decision making, along with the analyses representing the coordinated efforts of many individuals, each of whom contributes specific skills to the task. The objectives of drilling planning are: First, to identify and address all significant engineering parameters, that are likely to have a direct or indirect impact on the proposed drilling venture. Next, prepare a drilling plan that addresses all issues and that will enhance the success of the prospect well by drilling in safe, efficient, and economical manner in compliance with all federal, state, and local government rules and regulations. Therefore, my case study would be Well Gelama Merah, it is a vertical exploration well located in Block SB-18-12 Offshore Sabah, Malaysia. I will use the data from Well Gelama Merah to develop a systematic, reliable, economical, and safe, vertical oil well drilling planning guideline. The effect and functions of each steps and equipments utilized in the development phase of an oil field (Gelama Merah) would be analyzed and technically justified. The relevance and importance of each of the procedures would be explained, and sample calculations would be provided as a guideline for future reference.

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CHAPTER 1
INTRODUCTION

1.1 PROBLEMS STATEMENT

There is a need to develop a complete drilling planning manual for the use of junior engineers, students and anyone interested to learn the overall procedures, concepts and calculations in oil well drilling planning.

1.2 OBJECTIVES

The objectives of the project are:

a) To develop a systematic, reliable, economical, and safe vertical oil well drilling planning guideline for a particular well (Gelama Merah).

b) To analyze and technically justify procedures, material and equipments used during the well development phase, which might have a direct or indirect impact on the proposed drilling venture.

1.3 METHODOLOGY

The project is conducted on a research and analysis basis. Each procedures, materials and equipments used throughout the well development phase for a particular oil well would be analyzed and technically justified. Drilling manuals, well planning books and journals related to well planning would be used as reference for research purpose. The efficiency of material and equipments used with respect to production rate, the suitability of rig selection, drilling systems and equipments would be discussed. Drill bit types, strength and Rate Of Penetration (ROP), drilling technique, type of drilling mud, casing and cementing procedures and others, would be tabulated, evaluated and analyzed accordingly in order to design a systematic drilling planning manual.

1.4 SCOPE OF STUDY AND FEASIBILITY WITHIN TIME FRAME

The scope of study is mainly about designing a systematic drilling planning and drilling guideline for an oil well. The study will be divided into two stages, the first stage involves researching the basic and fundamental procedures, materials and equipments involved in the well planning and drilling phase. Next, selecting oil well and obtain relevant geological data and well formation properties for that well. The second stage would focus on developing and designing a systematic drilling planning programme for that oil well. All the procedures, material and equipments which should be utilized in the well planning phase would be evaluated, compared and analyzed to determine the best drilling planning programme. Result of the analysis would be tabulated and discussed further. In order to fit within the time frame, all the research and analysis will be carried out according to the initial planning and allocated time duration.

CHAPTER 2

THEORY & LITERATURE REVIEW

2.1 THEORY

A good drilling planning should provide the wellsite personnel with everything they need to know to plan and drill the well. Hence, avoid cluttering up the drilling program with extraneous and unnecessary information. A technical justification should be included as its purpose is to document major decisions made while well planning. Make references where appropriate to the technical justification within the drilling program. The planning should contain the following elements as relevant checklist [1] :

Area geology. This includes identification of formation tops to be penetrated, problem zones, shale, abnormal conditions and possible production interval. Next, formation pore pressure and fracture gradients. An accurate knowledge of formation pressure and fracture gradient is vital geological info, which helps proper selection of casing setting depths, with the optimum type of drilling fluid to be used in each interval of wellbore. Casing program, contains casing schematic that represents well construction details. Mud program, a detailed discussion by interval, of desired drilling fluid type, properties and maintenance.

Next, cementing program. This section should include volume of cement needed, bottom hole temperature, estimated amounts and types of cement to be used, setting time allowed, curing time required, and types of shoe, float, scratchers etc. BHAs and other types of equipments that generally improves of drilling should be specified here. Hydraulic program dictates the rig hydraulic power requirements.

Optimum utilization of hydraulic horsepower at the bit improves ROP and increases bit life. Drill bit program. The types of bit to be used must be specified and optimum operating conditions should be selected for each bit (WOB, rpm, optimum flow rates and corresponding optimum nozzle size). At last but not least, the selections of drilling rig.

2.2 Literature review

2.2.1 Formation Pressure: Gelama Merah

Overburden Stress:

Local overburden stress values for Well Gelama Merah were calculated from bulk density data obtained from Schlumberger wire line density logs in Well Bokor due to unavailability of wire line data in Gelama Merah. Best fit curve was established with the equation and constant below and used for the calculation of formation pressure gradient and fracture gradient.

S = As in (TVD)^2 + Bs in (TVD) + Cs, where

As = 0.0168

Bs= -0.1875

Cs= 1.31

Collection of cutting samples started at 553m; below the 13 3/8" casing shoe while drilling of the 12 ¼" hole.

12 ¼ " HOLE PHASE : 553 m – 1636 m

553m to 1120m : Interbedding of Sandstone, Claystone and Dolomite

SANDSTONE: Light gray, light brownish gray, clear to translucent, occasionally transparent, predominantly soft to friable and locally medium hard, very fine quartz grains, occasionally medium grains, sub angular to sub rounded, rounded in part, moderately to well sorted, locally argillaceous matrix, silty, none to slightly calcareous, generally poor visible porosity, fair porosity in part. Traces of carbonaceous matter and pyrite were observed in this interval. No show.

CLAYSTONE: Light gray , olive gray, brownish gray, light whitish gray, soft to firm, medium hard in part, amorphous to sub blocky, locally silty, very fine quartz grain, none to slightly calcareous. Traces of carbonaceous, matter, pyrite and dolomite were observed in this interval.

DOLOMITE: Yellowish brown, brownish gray, hard to very hard, sub angular to angular, sub concoidal to brittle fracture and no visible porosity.

1120m to 1320m; Interbedding of Claystone and thin Sandstone

CLAYSTONE: Light whitish gray, brownish gray, medium gray in part soft, firm in part, amorphous, locally silty in part, very fine quartz grain, slightly calcareous. Traces of carbonaceous matter and trace to 5% pyrite were observed in this interval.SANDSTONE: Light gray, light brownish gray.

1320m to 1636m; Interbedding of Sandstone and Claystone

SANDSTONE: Olive gray to light gray, off white, clear to translucent, soft to friable, medium hard in part, predominantly silt quartz grains, very fine to fine loose quartz grains, sub angular to sub rounded, moderately well sorted, locally argillaceous matrix , silty in parts, weak to moderately calcareous cemented, generally poor visible porosity. Traces of carbonaceous matter, pyrite and lignite were observed in this interval.

CLAYSTONE: Predominantly olive gray to white gray, brownish gray, very soft to soft, amorphous, silty in part, trace very fine quartz grains, moderately sticky , none to slightly calcareous and traces of carbonaceous matter.

This well is in normal pressure from sea bed downward to TD at 1636 mMD as shown in MDT pressure data, the pore pressure gradient value within the range of 8.27 to 9.2 ppg.

The Dxc plot generally shows an increasing trend from the seabed to the well TD. However the points were shift in the plot at the depth 1110 mMD mainly due to the changes in lithology, claystone, and sandstone. The Dxc plot below the depth of

1110 mMD was less scattered and increase in normal trend to 1320mMD. Below 1320mMD the Dxc plot were shift to left due to the lithology drilled is sandstone bed. At 1590mMD to bottom at 1636mMD/ 1635.8mMD, the plot increases in normal trend. ***No overpressure occurrence was observed in this well, based on Dxc plot (Exponent Pressure Log).***

Fracture pressure:

Only one leak off Test (LOT) was conducted in Gelama Merah-1 with the result tabulated below.

Values for the coefficients a and b in the formula (Ln K = a[Ln[TVD3.281] + b] used for calculating Poisson coefficient K, is obtained by fine tuning the fracture gradient plot relative to the available fracture gradient data point that were obtained from leak off tests. At TD of 1636m, Gelama Merah-1 would have a fracture gradient of 18.09ppg as extrapolated by the best fit curve (appendix D1)

Pore Pressure:

Pore pressure evaluation while drilling Gelama Merah-1 well based on mainly on real time gas evaluation. The Dxc was quite ineffective in this well because of the unconsolidated formation, which resulted in scattered points. The interbeded sandstone/claystone formation also produces unrelated shift in the plot.

2.2.2 Casing Program

The casing seat selection is mainly dependent on the pore pressure, the fracturing pressure and the mud weight.The relationship between pore pressure and fracture pressure determines the maximum length of each open hole section. Given pressure prognosis, the casing seats are always determined starting at the bottom of the well and working upwards. In this manner the minimum number of casing string will be determined. (Bernt S. Aadnoy ,1999.p.23).

The best way to understand how these two parameters are used is to make a plot of pore pressure and fracture pressure versus depth. Figure 2.1 shows a plot of the formation pore pressure versus depth on the left and the fractures pressure on the right together with the safety margins in between, which are mud density and kick margin.

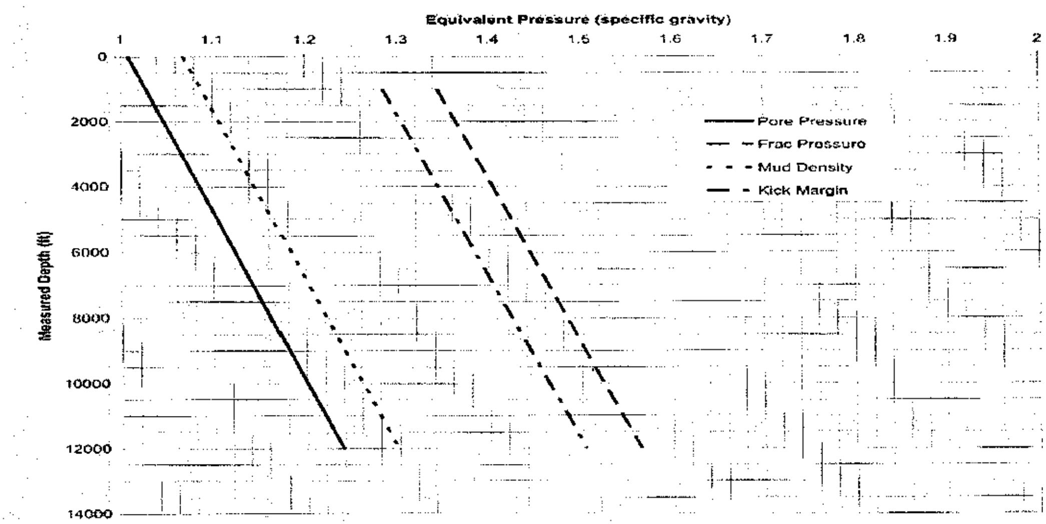


Figure 2.1 Pressure Margin

The mud density must be slightly higher than the formation pressure to prevent formation fluids from entering the wellbore, while, less than fracture pressure to avoid formation fracture. (Ted.G.Byrom,2007.p.20). Figure 2.2 shows surface casing shoe determination.

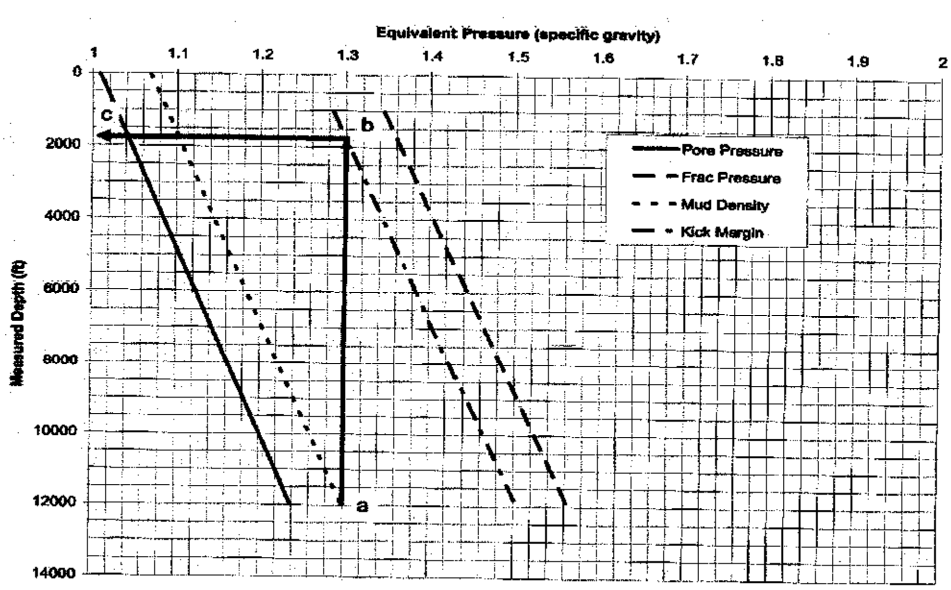


Figure 2.2 Surface casing shoe determination

This is the method to determine the setting depth of the surface casing. Ted.G.Byrom (2007). In the figure above we can see that, the mud density required to contain the pore pressure plus the safety margin at 12000ft is 1.4sg, but above 1700ft, that mud density begins to exceed the kick margin. To be specific, we cannot drill safely to 12000 feet in the well unless the hole is cased down to 1700feet or more, because the mud density required to contain the pore pressure at the bottom is greater than the fracture pressure at the surface.

After finding the number of casing string required and the setting depth, the next step in the design would be to select the sizes of casing and wellbore.

Two parameters needed to select casing size:

- Hole size determine casing size
- Hole size at any point in the well except the surface is determined by the previous string of casing

Casing load determination:

Casing strength could be evaluated by analyzing the type and magnitudes of the loads the casing could withstand.

Three basic types of loads usually encountered:

Collapse loads: The differential pressure load at which the external pressure exceeds the internal pressure, tending to cause the casing to collapse.

Burst loads: The differential pressure at which the internal pressure is greater than the external pressure, tending to cause the casing to burst or rupture.

Axial loads: These are the tension or compression loads caused by gravitational and frictional forces on the pipe.

Collapse load and Burst load are functions of pore pressure, fracture pressure and drilling or cement pressures. (Ted.G.Byrom,2007.p.25)

And the final selection phase would include:

- Development of design loads for collapse and burst
- Initial casing selection for collapse and burst
- Development of axial load curve
- Development of axial design curves

2.2.3 Mud program

Density is the weight of a mud. Density directly affects the hydrostatic pressure of the mud column. Mud weight could be measured by calculating its hydrostatic pressure at given depth using formula. William E.Jackson (2000).

Ph = DxWmxC

Where,

Ph = hydrostatic pressure

D = depth

Wm = mud weight

C = a constant

C depends, on the unit used to express the mud weight, if the weight is in ppg, C=0.052

Ph(psi) = D(ft) x Wm(ppg) x 0.052

Properties of Mud

Gel strength:

It is determined in the two speed direct indicating viscometer by slowly turning the driving wheel on top of the instrument by hand and observing the maximum deflection before the gel breaks. The same procedure is followed in the multi speedviscometer, except that the cylinder is rotated at 3rpm by the motor. Gel strength measured after allowing the mud to stand quiescent for any time interval of interest but they are routinely measured after 10seconds (initial) and 10minutes.

Viscosity:

It is measured using the Marsh Funnel. The procedure is is to fill the funnel to the level of the screen and to then observe the time (in seconds) of efflux of one quart.

Density:

It is measured by weighing a precise volume of mud and dividing the weight by volume. The mud balance provides the most convenient way of obtaining a precise volume. The procedure is is to fill the cup with mud, put on the lid, wipe of excess of mud from the lid, move the rider along the arm till a balanced is obtained and read the density at the side of the rider towards the knife edge. George R.Gray & H.C.H Darley (1948)

Basic mud classifications:

Drilling fluids can be divided into seven major classifications, depending on the continuous phase fluid and the type and condition of the major additive within the continuous phase. They are as follows:

- Fluid with water as the continuous phase and with clays present dispersed throughout the water.
- Fluids with water as the continuous phase and with clays present inhibited from dispersing throughout the water.
- Clear fluid systems based on water with soluable salts used to control density. Brines may include soluble solids that can be removed from the reservoir face by circulating acid past the reservoir.
- Fluids with oil as continous phase and less than 10% water by volume, with any water forming an emulsion of water within the oil.
- Fluids with oil as the continous phase and more than 10% water by volume, with the water forming an emulsion of water within the oil.
- Fluids with air as the continous phase.
- Water based system incorporating air present in gaseous form within a liquid.

In selecting the most suitable type of drilling fluid, many different factors must be considered. Overall, the best would be the mud system which gives the lowest overall cost of drilling each hole section, except through the reservoir. The direct cost of the fluid itself, however, if the mud was not optimized for the formation to save money, then, greater amount of money would be wasted than that would have been saved on the mud bill. Mud cost must be considered, but only to choose between technically suitable systems. Physical, rheological and chemical characteristics can be defined for each hole sections, leading to a list of requirements for the mud system of choice.

Functions of drilling fluids:

- Transporting cuttings to the surface
- Suspending the cuttings when the circulation stops
- Cooling the bit and lessening the drill string friction
- Consolidating the wall of the hole
- Preventing inflows of formation fluids into the well

2.2.4 Cementing program

An important part of cementing is to determine the volume of slurry that would be required. Ellen Schroeder (1983).

To determine cement volume requirements (in English units only)

1. Multiply hole diameter times itself to obtain hole capacity in barrels per 1000ft(round off hole size to nearest in.upward- e.g 12 ½ in = 13in)
2. Multiply casing diameter times itself and subtract this number from hole capacity
3. Divide hole depth by 1000
4. Multiply (3) by (2) to obtain volume in bbl.

Or

Volume = (hole diameter)2 – (casing diameter)2

WOC (waiting on cement) time is required in order for the cement to attain strength sufficient to

- Anchor the pipe and withstand the shocks of subsequent operations
- Seal permeable zones for prevention of movement of formation fluids behind the pipe

Cement additives:

Accelerators: These products speed up cement setting at low temperature or offset the retarding effects of the other additives. They help shorten waiting on cement time before drilling operations can be resumed.

Retarders: These additives slow down cement setting and thereby lengthen thickening time for pumping the cement into place. They are used when high down hole temperature or the accelerating effect of another additives might dangerously reduce the time available for pumping cement.

Extenders: These are the lightweight, inert materials mixed with cement and designed to reduce both slurry density and costs. However, most lightweight additives have an effect on cement setting time and compressive strength. Special additives are often necessary to offset this tendency.

Fluid loss additives: These agents stop the slurry from losing water by filtration into permeable formations. Water loss may trigger either unwanted setting or no setting at all since not enough water is available for hydrolysis and crystallization of the cement components.

2.2.5 Hydraulic program

Pump input horsepower = 10D^2, where D = hole diameter in inches

Pump input power should be close to the value given by the 10D^2 rule to maintain efficient hydraulic effect at the bit. Reducing the pump input power by one half may require reducing bit weight by as much as 66percent and this could reduce penetration rate by 40percent.

Hydraulic horsepower = PxQ/1714

Where, P = pressure, Q = fluid flow, 1714 is constant.

Evaluation of pressure loss could be done by using "Pressure loss through the surface equipment table". Ellen Schroeder (1983).

Prepared charts can be used to calculate optimum bit nozzle sizes. (Ellen Schroeder, 1983.p.50)

CHAPTER 3

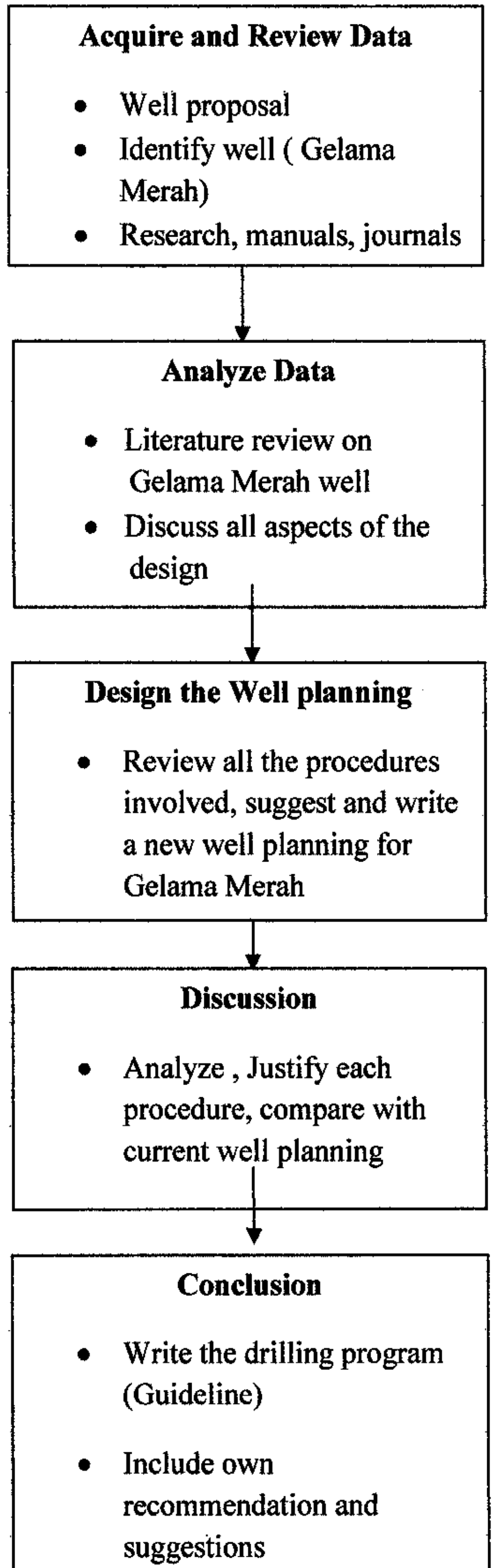
METHODOLOGY/PROJECT WORK

3.1 METHODOLOGY GANTT CHART

No.	Detail/ Week	1	2	3	4	5	6		7	8	9	10	11	12	13
1	Project title selection and start														
2.	Preliminary research work							Mid-semester break							
3.	Preliminary report submission														
4.	Study on fundamental concepts related to the project														
5.	Study on the phases involved in well planning														
6.	Submission of progress report														
7.	Seminar (optional)														
8.	Study on the calculations involved in the well planning														
9.	Preparation of final report														
10.	Submission of final report														
11.	Oral presentation														

Table 3.1 Gantt Chart

3.2 RESEARCH METHODOLOGY FLOW-CHART



3.2.1 Detailed Descriptions

(a) Acquire and Review Data

Obtain real well data such as the geological column, pressure, temperature. Gathering info such as well planning books, manuals, journals and other references. Review and understanding the procedures involved. Obtain real well data, Gelama Merah well.

(b) Analyze Data

Deep analysis on all the data which have been gathered earlier. Preparing justification and technical analysis on the importance and suitability of each phase in well planning. Detailed literature review on all the procedures involved in current development phase of GelamaMerah well.

(c) Design the Well planning

Based on the review and background studies on Gelama Merah well. A new well planning would be designed for the Gelama Merah well, which would be much more systematic, reliable, economical, and safe and environmentally friendly compare to the existing one. Plus, my work would include relevant explanations and designed such a way, that it could be used as a general guideline and reference for the well planning process by others.

(d) Discussion

The relevance of each procedure would be compared, analyzed and justified in detail.

(e) Conclusion

The final guideline would be the most systematic, reliable, economical, safe and environmentally friendly oil well planning and guideline.

CHAPTER 4

RESULT & DISCUSSION

4.1 DRILL BIT SELECTION

Good geological info vital for bit selection: Soft formation or hard formation

Two options available: Roller cone bits or fixed cutter bits

Roller cone: Suitable in soft formations

Fixed cutter: For hard formation

Fixed cutter:

- PDC
- Fish tail
- Natural Diamond

Roller cone bits:

- Milled tooth
- Tungsten Carbide Insert (TCI)

Since formation hardness is so varied and, there are so many different types of bits, it is not easy to choose the best one for the formation that is being drilled.

The most important consideration affecting bit design is the type of formation the bit will be drilling.

Is it hard or soft?

Is it composed of abrasive sand?

Is it sticky, heavy shale?

Is it porous chalk?

The main formation of Gelama Merah well is categorized as soft including soft sticky, low compressive strength, and high drill ability, such as clay and unconsolidated sand.

Therefore, since very large portion of this well is consists of soft clay and sandstone, Roller cone bits is selected as the most suitable and cost effective drill bit.

Based on "World Oil's 2008 Drill bit Classifier" catalog, for Soft & Soft Sticky formation, available drill bits which satisfy our requirements are:

Manufactured by: Halliburton

Bit number 1

- XT1 115, 26 inch
- Recommended WOB (lb/in diameter) = 1000-5000
- Bit RPM= 80-300
- Special feature= G (Gauge/body protection)

Bit number 2

- XT1 115, 17 1/2 inch
- Recommended WOB (lb/in diameter) = 1000-5000
- Bit RPM= 80-300
- Special feature= G (Gauge/body protection)

Bit number 3

- XS4 217, 12 ¼ inch
- Recommended WOB (lb/in diameter) = 2000-6000
- Bit RPM = 40-250
- Enhanced cutting structure

Since well formation is mainly consist of clay & sandstone, we categorise our formation as soft including soft sticky, low compressive strength, and high drillability, such as clay and unconsolidated sand.

We choose, Steel Tooth Roller Cone Bit due to these reasons:

- Cheaper compare to Fixed cutter (PDC & Natural diamond) and has better penetration in soft formation

- Very robust and assist in recognizing changes in pore pressure (data) which could be very useful in drilling activities

- A roller cone bit crushes the rock because of the great weight applied on the rock by the bit's cutters. By offsetting the cones, the crushing action is combined with a scraping action that is highly effective, especially in soft formation.

- It has widely spaced, self cleaning teeth. This design prevents interference from the cuttings that cause a bit to ball up.

- Extended jets that take the flow closer to the bottom helps bottom hole cleaning.

4.2 CASING SIZE SELECTION

Casing size selection based on Casing chart for unconsolidated formation. Best match between sizes of drill bit & casings available in market: Figure 4.1 shows casing selection chart.

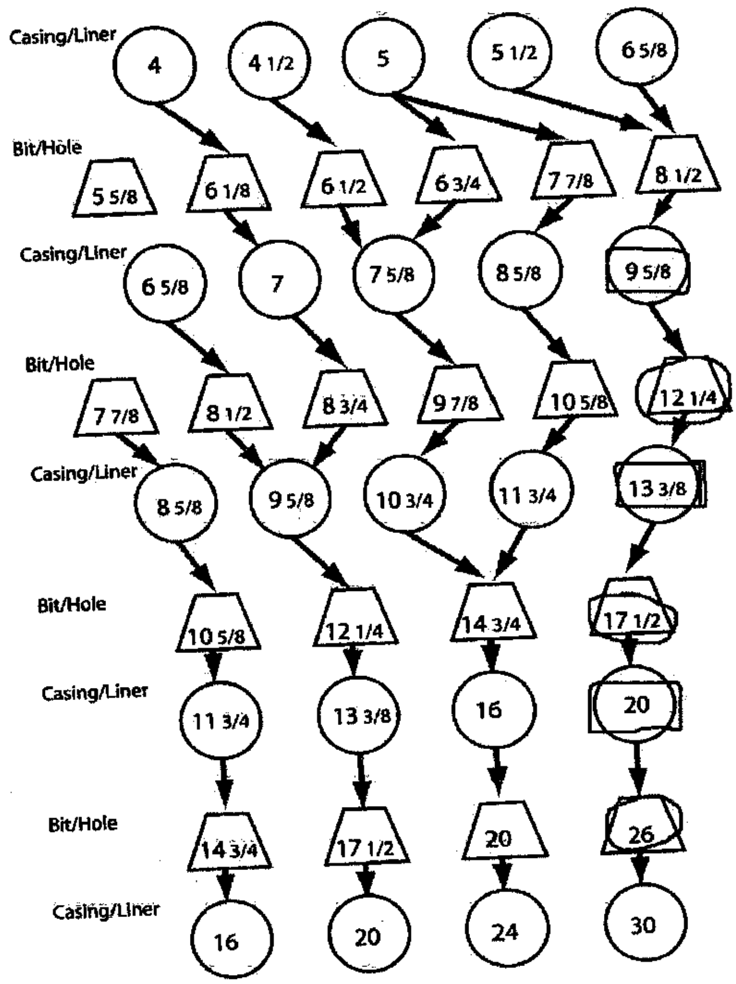


Figure 4.1 Casing Selection Chart

Since, there is no any particular method or formula to determine conductor casing shoe or depth. Conductor casing size 20 inch is chosen based on conventional practices in this particular well area. Surface casing and Production casing selection is done based on the available Casing chart for unconsolidated formation.

4.2.1 Casing setting depth determination

Table 4.1 Casing setting depth based on median line method.

Depth (m)	Pore pressure(ppg)	Fracture pressure(ppg)	Mud density margin(ppg) (+0.06)	Kick margin (-0.06)
100	10.8	13.5	10.86	13.44
200	11	13.7	11.06	13.64
300	11.2	14	11.26	13.94
340 (Surface casing shoe)	11.3	14.2	11.36	14.26
400	11.5	14.5	11.56	14.44
500	11.8	14.8	11.86	14.74
600	12	15	12.06	14.94
700	12.2	15.5	12.26	15.44
800	12.3	15.8	12.36	15.74
900	12.8	16	12.86	15.94
1000	12.9	16.2	12.96	16.14
1100	13	16.8	13.06	16.74
1200	13.1	17	13.16	16.94
1300	13.4	17.2	13.46	17.14
1400	13.8	17.6	13.86	17.54
1500	13.9	17.9	13.96	17.84
1600 (Production casing shoe)	14	18	14.06	17.94

Table 4.1 Pressure Gradient

The Pore Pressure and Fracture gradient data were obtained from Gelama Merah well logging report. Based on the median line graph, the surface casing shoe would be set at 340m, while the production casing shoe would be set at 1600m.

Number of casing: 3

Casing Setting depth:

- Conductor; 80 m (casing setting depth is based on the local practices or conventional method)
- Surface casing; 340 m
- Production casing; 1600m

From our graph (figure 4.2) we set surface casing shoe at 340m because, the mud density required to contain the pore pressure plus the safety margin at 1600m is 14.1ppg, but above 340m, that mud density begins to exceed, the kick margin. To be specific, we cannot drill safely to 1600m unless the hole is cased down to 340m or more. Because the mud density required to contain the pore pressure at the bottom is greater than the fracture pressure at the surface.

4.2.2 Determine Surface Casing Collapse load, Burst load

Collapse load:

Task is to determine the least pressure inside and maximum outside which could occur. In most well, the most serious internal collapse loading is atmospheric pressure (an empty well bore).

Calculate: Surface Casing Collapse load

Assume internal casing pressure is zero and the external pressure at 340m is due to mud pressure(mud density). The collapse load at 340m is

Pressure @shoe = (specific weight)(h) – 0 = (9.81)(specific gravity)(998)(h)-0

Thus, at h=340m,

= (9.81)(1.36)(998)(340)

= **<u>4527 kPa</u>**

The collapse load at surface is zero, since there is no external pressure. Figure 4.3 below shows collapse load for surface casing.

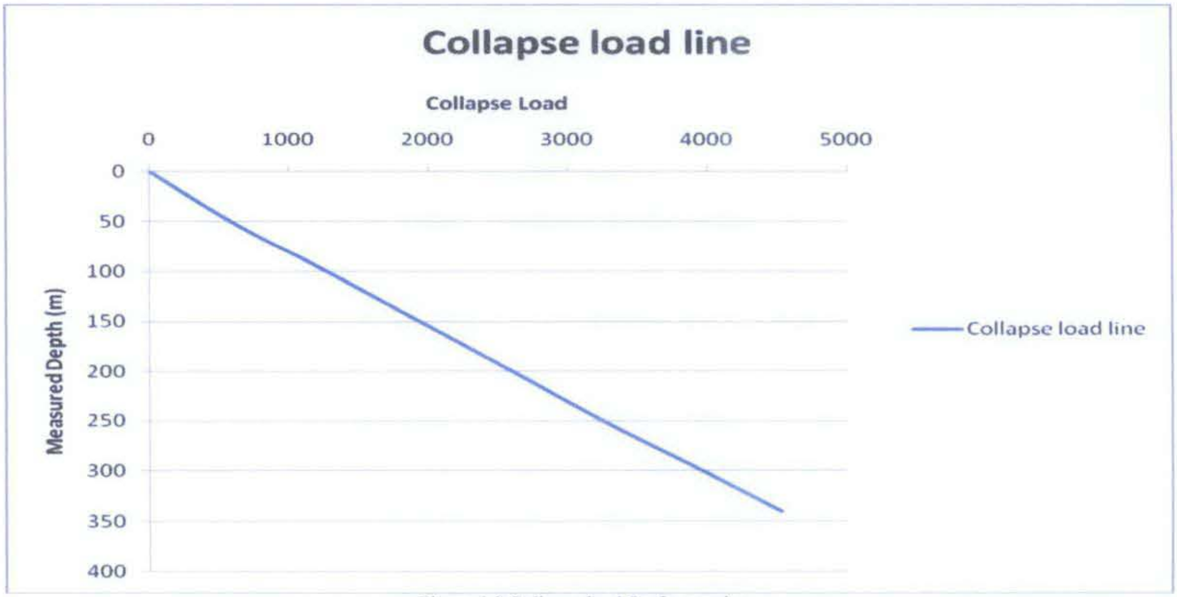


Figure 4.3 Collapse load Surface casing

Surface casing Burst load:

Maximum anticipated internal pressure & minimum anticipated external pressure. This scenario could occur at the surface where formation pressure (external) at its minimum, while internal pressure exerted by the expanding gas (kick) inside the casing is at the maximum.

At the shoe, the burst load is the fracture pressure of the formation below the casing less the external pressure at the casing shoe, which equivalent to a fresh water gradient.

Here we calculate the burst load at the shoe at 340 m, which is the fracture gradient at the shoe.

P@shoe = Pfrac-Pwtr = (SG frac – SG wtr)*h

=0.052(1.69-1.0)(8.33)(1115)

=**333.25psi or 2297kPa**

Next we calculate burst load at the surface. The most serious case in this part is when we have surface casing full of gas, all the way from the shoe to the top, this gives us the maximum pressure at the surface and such pressure is quite possible in kick situation. We calculate gas pressure , assuming pure methane.

*methane is selected since methane is the lightest of all the possible gases encountered in oil & gas wells, hence it represents the worst case load on the casing.

Calculate the pressure at the shoe, 340m, which is the fracture pressure of the formation.

Pfrac= 0.052(1.69)(8.33)(1115)

= **816 psi or 5626kPa**

Based on temperature data from Gelama Merah, temperature @ 340m is 35 Celcius.

Then the surface gas pressure is

P2=P1 e (M(h2-h1)/(zRT))

$P1$ = pressure at point 1, $P2$ = pressure at point 2

$h1$ = vertical depth of point 1

$h2$ = vertical depth of point 2

M=molecular mass of gas

R= ideal gas constant at standard gravity

Z= compressibility factor of gas, T= absolute temperature between points 1 & 2

For SI units

Z = 1 (for methane)

M = 16g/mole (methane)

R = 847.8 g.m/mole.k @ standard gravity

Thus, the surface gas pressure is

$P_{surf}=5626\, e(16*(0-340)/847.8*(95+460))$

= **5561 kPa**, Since there is no external pressure at the surface, then this value is also the burst load at the surface.

Determine Production Casing Collapse load, Burst load:

Our production casing is set from the surface to 1600m. The bottom hole pressure is equivalent to a 1.68 sg. We need not to be concerned with the fracture pressure in the production casing loading. The collapse loading we consider is that the casing would be empty and the pressure on the outside is equivalent to the mud it was run in, 1.69sg.

The collapse loading for production casing is

- Empty on the inside
- Mud on the outside, 1.69sg

For collapse, the net load at the surface is 0, and at the 1600m, the net collapse pressure at the bottom of the production casing is due to the 1.69sg mud on the outside:

P surface = P outside- P inside = 0

P shoe = P outside – P inside = Specific Weight *h – 0 = 0.052(1.69)(8.33)(5249)

= **<u>3842psi or 26489 kPa</u>**

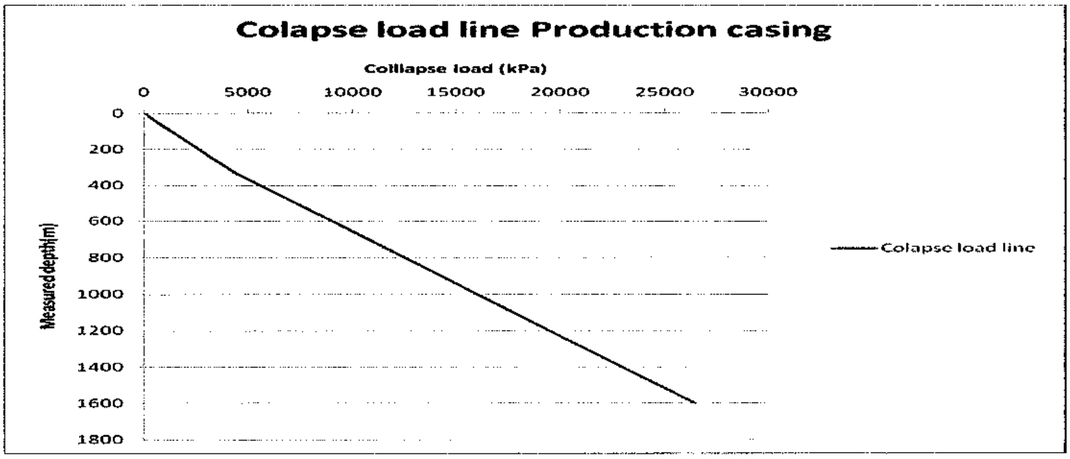


Figure 4.4 Collapse load Production casing

Production casing burst load:

For burst we assume that the pressure on the outside is equivalent to freshwater and on the inside, we consider that the gas kick might happen during production, resulting in full column of gas in the annulus between the tubing and production casing.

The formation pressure is equivalent to 1.68 sg., and from that, we calculate the pressure at the bottom of the casing.

Pshoe: Equivalent specific weight*h= 0.052(1.68)(8.33)(5249) = **<u>3819psi or 26331 KPa</u>**

Then, the gas pressure at the surface is calculated using methane:

For SI units

Z = 1 (for methane)

M = 16g/mole (methane)

R = 847.8 g.m/mole.k @ standard gravity

Thus, the gas pressure at the surface calculated using methane :

Psurf=26331 e(16*(0-1600)/847.8*(149+460))

=26331 e((-25600)/516310)

= **25057 kPa**

The net burst loads are then calculated.

P surface = 25057 – 0 = **25057 kPa**

Pshoe = 3819 – 0.052 (8.33)(5249) = **1545psi or 10652KPa**

4.2.4 Design factors

Design factors represent the unknowns, the factors which we cannot reasonably measure. For example, design factors to account for uncertainties in the properties of materials, uncertainties in the dimensional tolerances of casing and uncertainties in the casing loads. Table 4.2 below shows Casing Design Factors:

Collapse	Burst	Tension
1.0-1.125	1.0-1.125	1.6-2.0

Table 4.2 Casing Design factor

Surface Casing Design factors considerations:

Collapse & Burst = 1.125

Load type	Initial load	Initial load* 1.125
Surface casing collapse load @ 340m	4527 kPa	5092 kPa
Surface casing Burst load @ surface	5561 kPa	6256 kPa
Burst load at the shoe @ 340 m	2297kPa	2584 kPa

Table 4.3 Surface Casing Design factor

Table 4.4 Production Casing Design factor

Load type	Initial load	Initial load* 1.125
Production casing collapse load @ 1600m	26489 kPa	29800 kPa
Production casing Burst load @ surface	25057 kPa	28189 kPa
Burst load at the casing shoe @ 1600m	10652kPa	11983 kPa

4.2.5 Selecting weight and grade of casing

Once the collapse and burst requirements are known, Casing design tables used to decide which of the available casings will handle the worst case burst and collapse pressure. The lowest available weight/grade of casing that is strong enough, apply sufficient desired safety factor and the most economical would be selected.

Surface casing: (Page 30 @ API Bulletin 5C2) (Table 4.5 Surface Casing grade)

Details	Values
Casing size	13 3/8 inch
Grade:	J-55
Weight	54.50 lb/ft
Collapse resistance	1130 psi

Production casing: (Page 24 @ API Bulletin 5C2) (Table 4.6 Production Casing grade)

Details	Values
Casing size	9 5/8 inch
Grade:	L-80
Weight	47 lb/ft
Collapse resistance	4750 psi

Conductor casing: (Page 33 @ API Bulletin 5C2) (Table 4.7 Conductor Casing grade)

Details	Values
Casing size	20 inch
Grade:	J-55
Weight	94 lb/ft
Collapse resistance	520 psi

Having calculated the minimum strength requirements and preferred weights and grades of casing, another most important factor in deciding which type of casing to select and when several types of casing satisfy the load requirements of the design is cost. In order to be most competitive and economical, our basic premise is to select the lowest grade first, then the lowest weight. Plus, the heaviest weight in any grade would be avoided, since that usually is special item, not readily available and often with too small an internal diameter to use common bit and tool sizes.

In the basic design for the surface casing and production casing, varieties of design factors have been examined. Typically, companies have a set of design criteria for a specific area and stays with those criteria for all design.

In general, the choice between two different types of casing for particular section is based on

- Cost
- Availability
- Simplicity of design
- Minimum number of crossover

4.3 CEMENTING PROGRAM

4.3.1 Calculating volume of cement for conductor casing:

Volume = (hole diameter*hole diameter) – (casing diameter*casing diameter)

Volume = (26*26) – (20*20) = 276 bbl per 1000 ft

And, because the calculation is for 262 ft, the 276 bbl is multiplied by (262/1000),

= 276*(262/1000)

= **<u>73 bbl or 408.8 cu ft</u>**

4.3.2 Calculating volume of cement for surface casing:

Volume = (hole diameter*hole diameter) – (casing diameter*casing diameter)

Volume = (18*18) – (14*14) = 128 bbl per 1000 ft

And, because the calculation is for 1115 ft, the 276 bbl is multiplied by (1115/1000),

= 276*(1.115)

= **<u>308 bbl or 6244 cu ft</u>**

4.3.3 Calculating volume of cement for production casing:

Volume = (hole diameter*hole diameter) – (casing diameter*casing diameter)

Volume = (13*13) – (10*10) = 69 bbl per 1000 ft

And, because the calculation is for 5250 ft, the 69 bbl is multiplied by (5250/1000),

= 69*(5.250)

= **<u>362 bbl or 2030 cu ft</u>**

Additionally, most operators prefer to include a 10% safety margin for cementing calculation.

4.4 MUD PROGRAM

Drilling mud properties impact the penetration rate by performing functions vital to cost effective drilling as well as, controlling the blowout and kick from occurring by compensating the pressure exerted by the formation fluids. Thus we must be able to determine the amount of pressure exerted by the formation pressure and drilling mud in particular depth in order to safely drill a well. The mud program is not same for every well. During the drilling period, the mud is always subjected to changes to deal with changes in formation and mechanical factors that affect the drilling rate. Density is the weight of mud. Density directly affects the hydrostatic pressure of the mud column. A heavy mud exerts more hydrostatic pressure at given depth compare to light mud.

Ph = D*Wm*C

Where,

Ph = hydrostatic pressure

D = depth

Wm = mud weight

C= constant

The value of C, the constant, depends on the units used to express the mud weight. If the mud weight is in ppg, the C=0.052. While, if in KPa, C=0.0098.

Ph (psi) = D(ft)*Wm(ppg)*0.052

Ph(kPa) = D(m)*Wm(kg/m3)*0.0098

Ph(psi) = D(ft)*Wm(S.G)*8.33*0.052, (S.G = Specific Gravity)

Example: Determine the hydrostatic pressure at the bottom of a surface casing shoe at 1115ft (340m) deep that has formation fluid density 14.1 ppg.

Ph= 1115 ft*14.1*0.052

Ph= 816 psi

We will be using these formulas and techniques excessively in the casing design and load determination calculations as well as, in calculating the pressure of the drilling mud during drilling each interval

Table below shows the comparison between calculated pore pressure for every interval and its corresponding drilling mud density with 0.06 safety margin. Table 4.8 below shows relation between depth and pressure gradient.

Depth (m)	**Pore pressure(ppg)**	**Mud density margin(ppg) (+0.06)**
100	10.8	10.86
200	11	11.06
300	11.2	11.26
400	11.5	11.56
500	11.8	11.86
600	12	12.06
700	12.2	12.26
800	12.3	12.36
900	12.8	12.86
1000	12.9	12.96
1100	13	13.06
1200	13.1	13.16
1300	13.4	13.46
1400	13.8	13.86
1500	13.9	13.96
1600	14	14.06

Light weight muds (less than 10ppg) exert less pressure on the bottom of the hole and allow cuttings to be removed efficiently with lower weight and rotary speed.

In effect, the rock drills more easily, provided the circulation system is properly maintained. Drilling with lightweight mud with its lower hydrostatic pressure can, however, increase the risk of kick.

While, if mud density is too high, high differential pressure exist between the mud column and the formation pressure creates a chip hold down effect that tends to hold the cuttings on the bottom of the hole. Unless, mechanical energy is increased, a drop in drilling rates occurs because the bit will be drilling the same material over and over again.

4.5 DRILL BIT AND BOTTOM HOLE ASSEMBLY (BHA) CONSIDERATIONS

According to World Oil's 2008 Drill bit Classifier, for Soft & Soft Sticky formation, available drill bit:

Manufactured: Halliburton

Bit number 1

- XT1 115, 26 inch
- Recommended WOB (lb/in diameter) = 1000-5000
- Bit RPM= 80-300
- Special feature= G (Gauge/body protection)

Bit number 2

- XT1 115, 17 1/2 inch
- Recommended WOB (lb/in diameter) = 1000-5000
- Bit RPM= 80-300
- Special feature= G (Gauge/body protection)

Bit number 3

- XS4 217, 12 ¼ inch
- Recommended WOB (lb/in diameter) = 2000-6000
- Bit RPM = 40-250
- Enhanced cutting structure

The mechanical factors of bit weight and rotary speed must be coordinated with bit selection to achieve optimal drilling rates. Generally, an increase either weight or rotation per minute (rpm) increases rate of penetration. The increase is almost directly proportional to the weight on the bit if the drilling fluid can manage to keep the bit clean enough. The basic rule is a weight of one ton per inch of bit diameter in soft formations and three tons in hard ones.

However, penetration rate can reach a maximum if the weight on the bit reaches the load limit which embeds a tooth entirely in the rock. Above this threshold, any extra weight is supported by the body of the cone which is pressed against the formation. As a result, bearing life is shortened with no corresponding increase in penetration rate. The drill string is the mechanical assemblage connecting the rotary drive system on the surface to the drilling bit. One of the main part of drill sting is drill collars. Drill collar is a steel weight whose mass provides the force to press the drill bit onto the formation.

For our drill bits, the manufacturer had provided the suitable range of WOB for each drill bit. Table 4.8 below shows Drillbit vs WOB.

Drill Bit	**Recommended WOB (lb/in diameter)**
XT1 115, 26 inch	1000-5000
XT1 115, 17 1/2 inch	1000-5000
XS4 217, 12 ¼ inch	2000-6000

Table 4.8 Drill bit vs WOB

Here we will discuss one example calculation related to WOB.

The example uses a 12 ¼ " phase with a rock bit that requires WOB of 2 tons per inch of diameter. The drill collars available on the well site are 9 ½ ", 8", 6 ¾ '. The drilling mud has density of 1.18.

The equation for the stability of this assembly can be written as:

P DC + P2*S = P1*S + WOB

WOB = **P** DC – (P1-P2)S

P DC = L*S*ds

P1-P2 = L*S*dm

Where,

P DC = drill collar weight

WOB = weight on the bit

S = drill collar cross section

P1 = hydrostatic pressure at Z1

P2 = hydrostatic pressure at Z2, L= Z1-Z2

Ds = density of the steel

Dm = density of the mud

Thus,

WOB = L*S(Dm+Ds)

= L***P** DC(1-Dm/Ds)

Sds= **P** DC weight per unit length

K = 1- Dm/Ds

K is the buoyancy factor.

In the example, K=0.849

Required WOB = 2ton*12.25 = 24.5 ton

Drill collar 9 ½ " : **P** DC = 323.2 kg/m

L = 24500/(323.2*0.849) = 89.29.

4.6 DRILLING HYDRAULICS

Hydraulics deal with the behaviour of a liquid in motion. Bit hydraulics concerns the circulating pressure available at the bit to clean the bottom of the hole. The hydraulic horsepower of the circulating fluid at the bit is crucial to the penetration rate because this horsepower removes the cuttings from the bottom of the hole. If the cuttings are not removed quickly, the bit merely regrinds them instead of deepening the hole.

Usually, much of the power produced by the mud pumps is lost in the circulating system through the surface lines, drill string, and annulus. These losses contribute no direct benefit to the drill bit performance. The power that is left can be used in different ways to help clean the bit/hole bottom, aid ROP by the direct effect at the bit face and drive down hole motors or turbines.

There are two current theories for optimum hydraulics. One gives the total nozzle area to maximise hydraulic horsepower. The other calculates for maximum hydraulic impact force on bottom. Maximising HHP gives greater pump pressure and lesser flow rate.

Hydraulic calculations:

Bit hydraulic horsepower (Bhhp) = Pb*Q/ 1714

Where,

Pb= pressure at the bit

Q = Flow rate

1714 = a constant

Example: We will assume certain values in this example since we do not have sufficient data from our real well data (Gelama Merah).

Calculate the bit hydraulic horsepower for a system that has system pressure losses of 650psi and total surface pressure of 2300psi. The pump output is 430gpm.

Bhhp = Pb*Q/1714

Pb = 2300 – 650 = 1650

Q = 430

Bhhp = 1650*430/1714

=**<u>413.9</u>**

Bhhp = 414. Thus, in order to test if this Bhhp is adequate for bottom hole cleaning, we can start by assume, (is the calculated Bhhp approximately 67% of the total hydraulic horsepower available at the surface?)

Hhp = P*Q/1714

= 2300*430/1714

= 577.01 hp

67% of hhp approximately equals required Bhhp: 577*0.67 = **<u>387hp</u>**

Thus, the Bhhp is adequate because the calculated Bhhp value, 414 is more than the required 67%, 387hp.

Besides this, prepared tables and charts can be easily used for calculating optimum bit nozzle sizes and other relevant values. The calculations involved in drilling hydraulics are best done with computer programs and these are available free from many companies. Calculating these pressures by calculator is tedious since they have to be repeated for each change in the flow path size and it is not practical in real life scenario.

Thus, due to this reason and insufficient data available, we will not going to look at any other calculations in this section.

The hydraulics plan frequently begins at the end of the hydraulics circuit by determination of the minimum annular velocity needed for transporting the cuttings out of the hole. The pump rate is then established, based on the required annular velocity . The rest of the hydraulics program can then be planned.

High drilling rates are important in almost all drilling operations. Methods used in planning the hydraulics program emphasize the amount of hydraulic horsepower at the bit to clean the bottom hole so that the mechanical forces of weight and rotary power can make faster hole. Whatever method is selected, the hydraulics program focuses on the selection of the correct combination of nozzle sizes for efficient bottom hole cleaning.

4.7 CHOOSING THE DRILLING RIG

Drilling an oil well out at sea means using either a floating platform or one that rests on the sea floor. Main factors taken into consideration during rig selection are water depth, cost, structural strength, availability and rig's resistance to surrounding harsh weather and environment. The support structure must be able to withstand harsh weather and oceanic force, as well as, fulfilling all the functions that are normally required.

Hence, since our water depth is only 42.8 meter, which is considered as shallow water, the most suitable, practical and cost effective selection would be **Jackups Rig**.

A jackup rig has a floating hull, usually triangular or square shape. At each corner is a large steel leg. The rig is towed to the well site with tugs. Once in position, the legs are moved down until they contact the seabed. By jacking the legs further down, the hull raises up out of the water.

The derrick is located on large cantilever beam that moves out from the hull, placing the derrick over side of the hull. This allows a jackup rig to move next to a platform and position the derrick above a well within the platform structure.

The largest jackups can drill in water depths up to 400feet (about 120m) and drill holes up to 30000ft (9100 m) deep. A jackup rig might cost between $30 000 to $70 000 a day, depending on age, capacity and equipment.

Suitable sea condition for successful operation of a Jackup rig.

- Wave height < 1.5 meters
- Wind < 15 knots
- Current < 1.5 knots

CHAPTER 5

CONCLUSION

The aim of this project is to develop a systematic, reliable, economical, and safe oil well planning guideline for a particular well (Gelama Merah well). The effect and functions of each steps and equipments utilized in the development phase of this well have been analyzed and technically justified. The relevance and importance of each of the procedures had been explained, and sample calculations have been provided as a guideline for future reference and manual.

This drilling planning manual includes relevant data, explanations and other user friendly features, and designed such way that, it could be used as a general guideline and reference for the drilling planning process by other people who are involved in oil well planning especially college students and junior engineers.

CHAPTER 6

RECOMMENDATION

One of the recommendations to further improve this manual in future is to include the manual and guidelines related to software used in drilling planning. There are lots of software in the industry which used in planning the drilling activity such as "landmark" software developed by one of the key player in oil and gas industry, this software does not only help to design and plan good drilling planning it also helps to save valuable time and manpower, plus avoid any simple mistakes which could cost millions.

Therefore, a proper use of software and technology in drilling planning is very vital and should be included in the manual.

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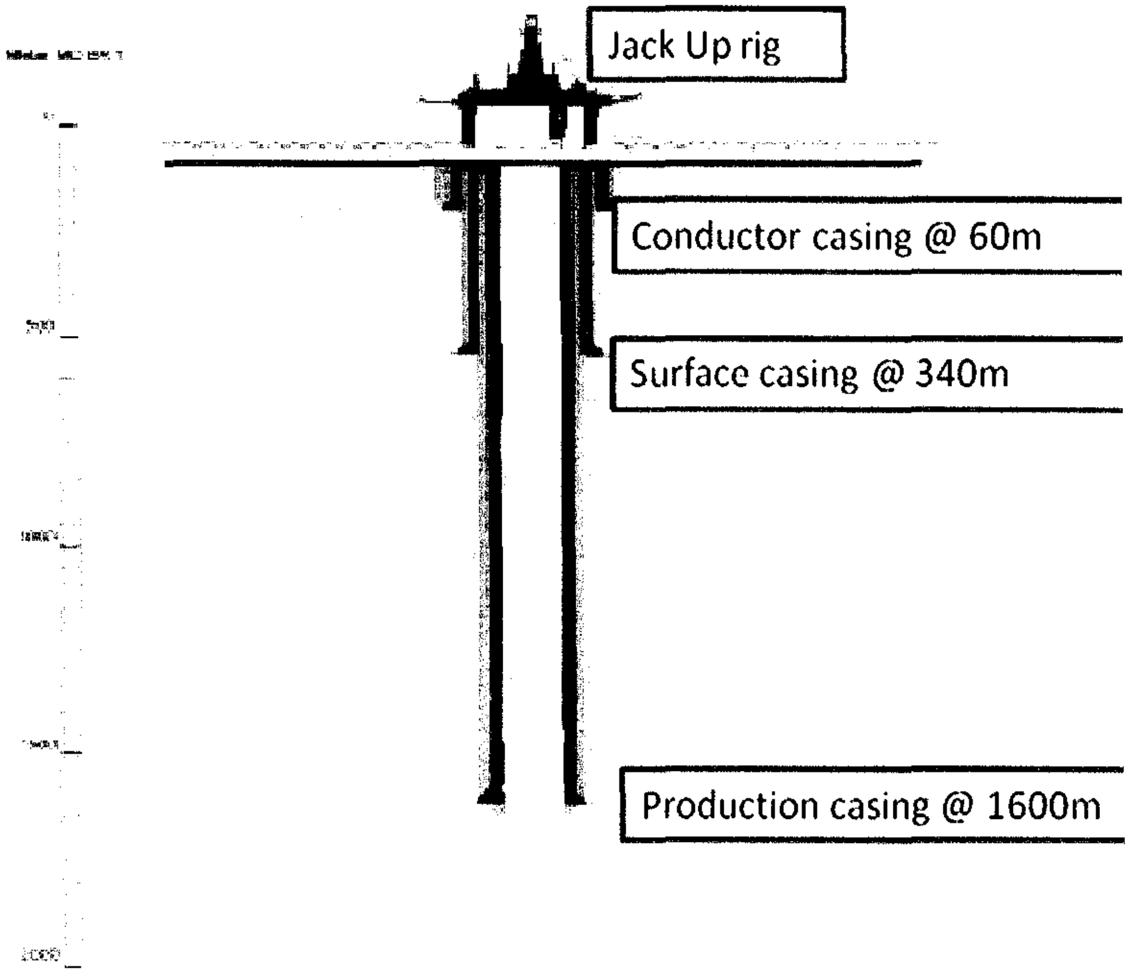
APPENDICES


Jack Up rig
Conductor casing @ 60m
Surface casing @ 340m
Production casing @ 1600m