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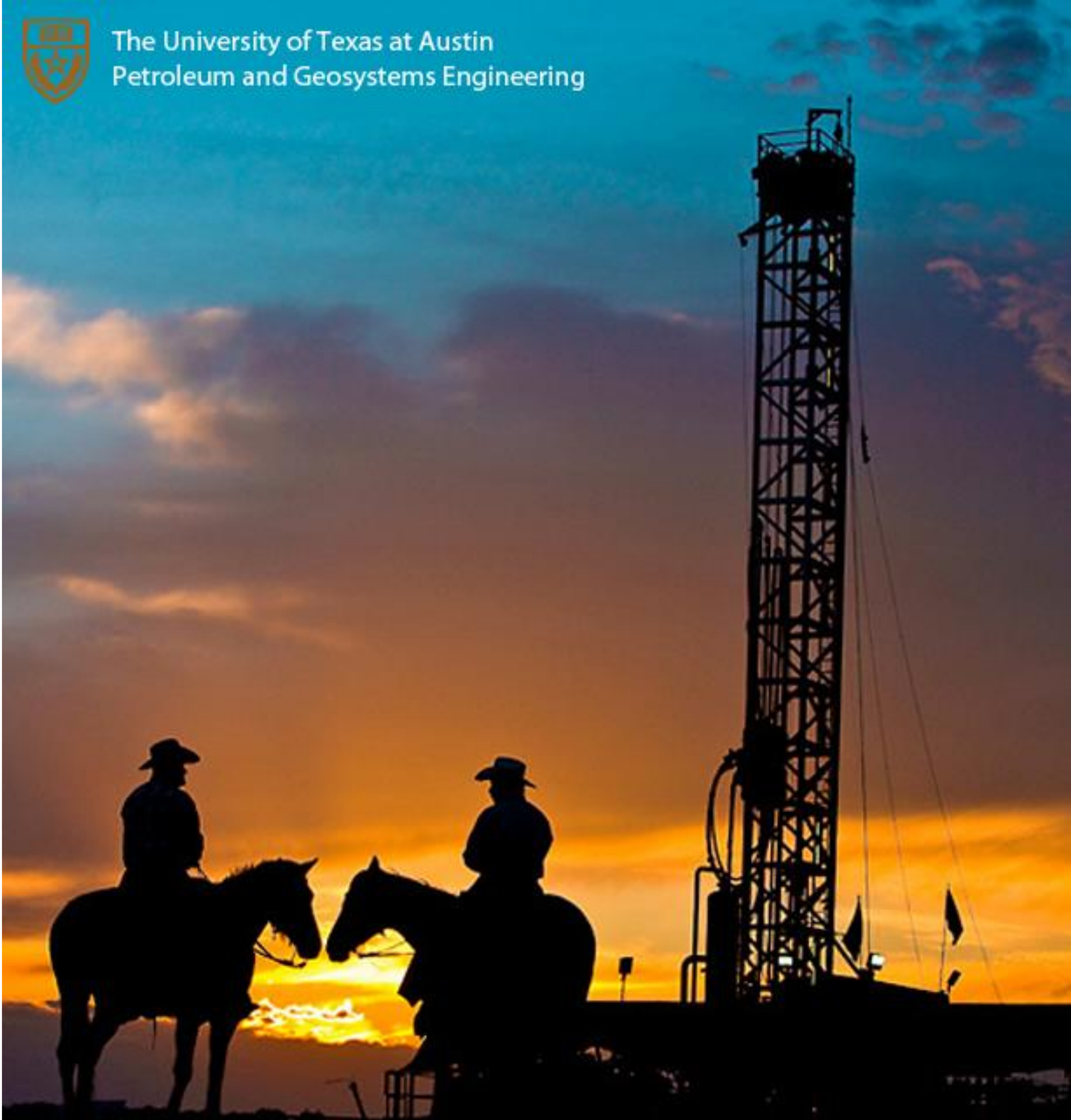
Petroleum and Geosystems Engineering



Drilling Horizontally In Eagle Ford

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Table of Contents

Exercise Data:

Casing: 9 5/8”, 47 ppf, N-80, BUT casing has been set at 4,000’.

Drill Pipe: 5” OD, 19.5 ppf, Grade E
Heavy Weight Drill Pipe: 5” in 30 foot joints. The number of joints you can choose.
Drill Collars: 20 joints (600’) of 6 ¼” OD x 2.50” ID, 87.35 ppf are available.

MWD is mud pulse telemetry with a gamma ray log for geologic positioning.

Bit: 8 ½”, bit type is your choice.

Current Mud: Water Base, 10 ppg, Yp=20 Lb/100 sqft, plastic viscosity = 10 cp. This can be changed to oil base mud of the same density if desired.

Mud Pumps: Two PZ12 triplex pumps with 6” liners with 12” stroke. Maximum pressure is 4200 psi. Output is 4.32 gal/stroke. Maximum speed is 110 spm per pump.

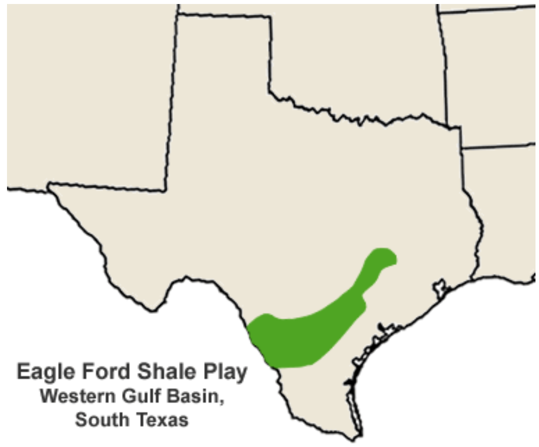
Stand pipe: Maximum pressure is 4,000 psi.

Top Drive maximum speed is 200 rpm.

Geologic Target: Top of the Eagle Ford Shale = 8,000’ TVD
Base of the Eagle Ford Shale = 8,200’ TVD
Target is in the middle of the shale to a MD TD of 14,000’.

The production casing is to be 5.5” OD run from the surface to TD. This casing is to be cemented in place. Multiple fracture jobs are to be done through this casing.

The Eagle Ford fracture pressure gradient is estimated to be 0.8 psi/foot.



Exercise (1)

For the first part of this well design, we designed a wellbore trajectory that will transition from vertical to horizontal as fast as possible because since we want to minimize the horizontal distance trajectory to reach the target pay-zone at 8100 ft., with an horizontal attitude of 90 degrees. To accomplish this we used the directional plan on canvas and inserted our measured depth of 14000 ft., angle of inclination and compass bearing at that depth. We also assumed that wellbore is pointed in the correct compass bearing and that it is maintained all the way to the True Depth. For angle of inclination we went from 0 deg to 90 deg, since, an assumption that we are drilling perfectly vertically at 0 deg inclination is made for this project. Generally, 1000 ft. is a standard practice in the industry to build your angle of inclination from 0 to 90 deg and a Dog Leg Severity (DLS) that cannot exceed 10-deg/100 ft. So, using these practices to achieve our angle of inclination from 0 to 90 degrees, we get a 900 ft. distance to build the angle. This calculation is also shown below in equation 1.

Equation 1:

$$DLS = 90deg/10 \times 100 = 900ft$$

Slightly different numbers are used for Compass bearing because equations will not work if we input 0, since you would an invalid value with a denominator of 0. Therefore, we directly inputted 10 deg after 0 deg as angle of inclination. Since normally while drilling, as a directional drillers you would like to have a smooth build angle, therefore we used use 2, 4, 6, 8, 10 deg and so forth to make this transition. This smooth horizontal displacement is gained at 10 deg, at an approximate 43 ft. This shows that it took us 43 ft. to build that angle, but that doesn't make much difference in terms of cost when you are placing a horizontal well like in our project. The main target zone where we want to enter the pay zone is 8100 ft., which means that the kickoff point is 1000 ft. above 8100 ft. Hence; we started building the angle at 7130 ft. and end at 14000 ft. where the wellbore is horizontal at 90 degrees. These calculations are shown in table 1.1 and 1.2 respectively, and the corresponding figure 1 and 2 shows the wellbore trajectory with the build angle.

Table 1.1: Calculations for Horizontal Wellbore Trajectory

	DATA			RESULTS				
SUR	MD	INC	AZM	DLS	TVD	Total N	Total E	Horz
NUM	ft	deg	deg	deg/100'	ft	ft	ft	Displ-ft
1	7130	0	0	0.000	7130.000	0.179	0.012	0.179
2	7230	2	1	2.000	7229.980	1.924	0.027	1.924
3	7330	4	0	2.001	7329.838	7.157	0.073	7.157
4	7430	6	0.1	2.000	7429.452	15.872	0.080	15.872
5	7530	8	0	2.000	7528.702	28.058	0.091	28.058
6	7630	10	0.1	2.000	7627.466	43.700	0.105	43.700
7	7730	20	0	10.000	7723.936	69.548	0.127	69.548
8	7830	30	0.1	10.000	7814.452	111.755	0.164	111.755
9	7930	40	0	10.000	7896.264	169.039	0.214	169.039
10	8030	50	0.1	10.000	7966.887	239.658	0.276	239.658
11	8130	60	0	10.000	8024.174	321.468	0.347	321.468
12	8230	70	0.1	10.000	8066.385	411.982	0.426	411.982
13	8330	80	0	10.000	8092.238	508.451	0.510	508.451
14	8430	90	0.1	10.000	8100.947	607.944	0.597	607.944
15	14000	90.5	0	0.009	8076.902	6177.871	5.458	6177.874

Table 1.2: Calculations for Horizontal Wellbore Trajectory

CALCULATIONS						
INC	AZM	Course	Course	Overall	Course N	Course E
rad	rad	Length-ft	TVD-ft	Angle-rad	ft	ft
0.000	0.000	7130.000	7130.000	0.000	0.179	0.012
0.035	0.017	100.000	99.980	0.035	1.745	0.015
0.070	0.000	100.000	99.858	0.035	5.233	0.046
0.105	0.002	100.000	99.614	0.035	8.715	0.008
0.140	0.000	100.000	99.250	0.035	12.186	0.011
0.175	0.002	100.000	98.764	0.035	15.642	0.014
0.349	0.000	100.000	96.470	0.175	25.848	0.023
0.524	0.002	100.000	90.516	0.175	42.207	0.037
0.698	0.000	100.000	81.812	0.175	57.283	0.050
0.873	0.002	100.000	70.623	0.175	70.619	0.062
1.047	0.000	100.000	57.287	0.175	81.810	0.071
1.222	0.002	100.000	42.211	0.175	90.514	0.079
1.396	0.000	100.000	25.853	0.175	96.469	0.084

1.571	0.002	100.000	8.709	0.175	99.493	0.087
1.579	0.000	5570.000	-24.045	0.009	5569.928	4.861

Figure 1: Wellbore Trajectory from Vertical to Horizontal Section

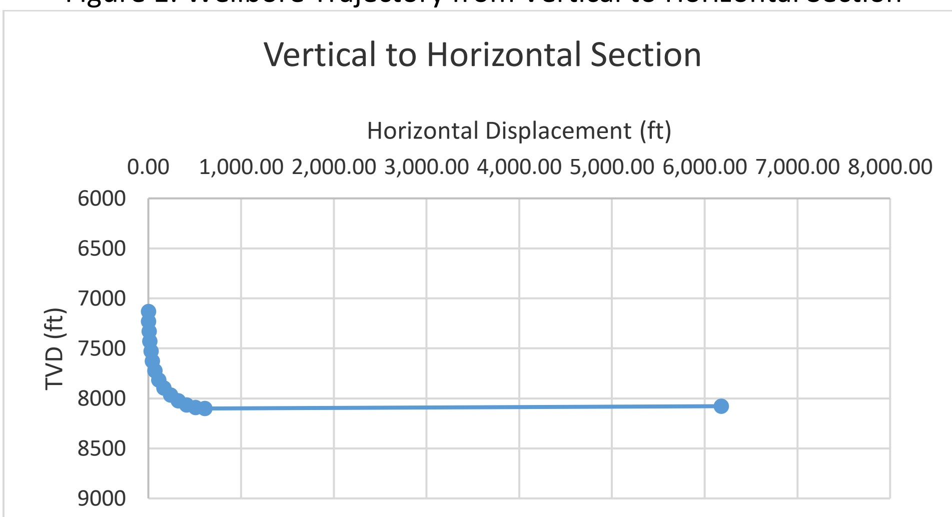
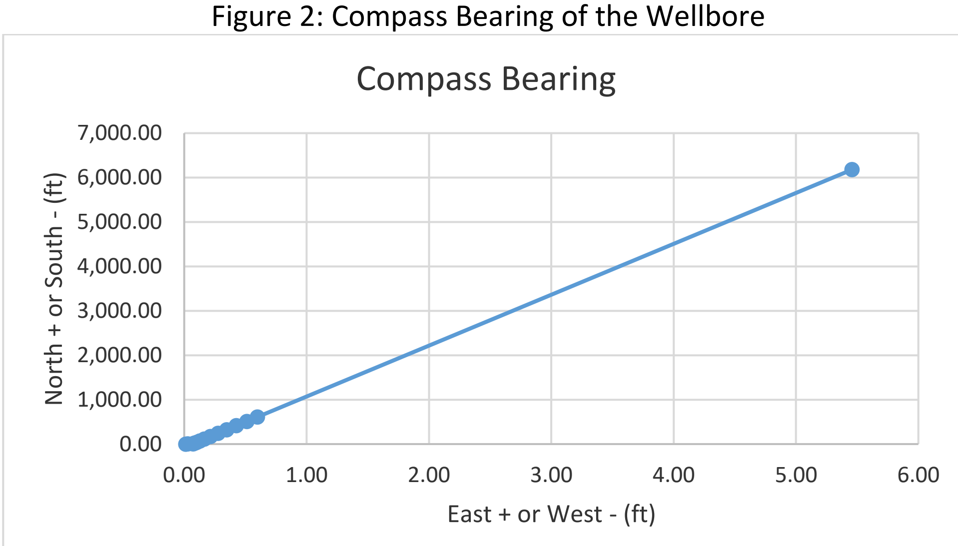


Figure 2: Compass Bearing of the Wellbore



The graphs show that our well is hitting the pay zone at 8100 ft. and the hole is going into correct compass bearing.

Exercise (2)

Our next exercise is to establish a bottom hole assembly for the horizontal part of the well. For this, we need to select drill bit size, motor, and pipe that connects the horizontal part back to the vertical section of the wellbore.

Bottom hole Assembly (BHA)

Drill Bit

For this particular project our chosen drill bit size is 8.5 in. In the vertical part of the well, we need to push down and apply more weight on the bit, therefore, we used good old-fashioned roller cone bit. These types of bit are able to handle larger weight on bit (WOB) and are designed to thrive in the environment of modest to low revolutions per minute (rpm). For the horizontal section, since we do not have any gravity to help push the drill bit into the bottom of the hole as we have in vertical, it creates a problem for us to use a roller cone bit. Gravity in the horizontal section makes the drill string to go against the lower side of the hole or essentially the bottom part of the wellbore. The low side of the wellbore has shear stress and is essentially supporting all the weight of the pipe. This makes pushing the bit into the bottom of the hole in horizontal much more difficult because the weight of the pipe in the horizontal section is no longer contributing to that, instead it is creating sliding friction. Therefore to combat this issue, we used a drag bit (PDC) for the horizontal section of the well. These bits thrive in the environment of high revolutions per minutes (rpm) with less WOB, and have a higher life expectancy. Furthermore, it allows us to rotate the entire drill string at a faster speed using the top drive, which cuts down the sliding friction.

Motor

For this lab, we adopted 4500 lbs. of WOB with the bit rotating at roughly 350 rpm. The next step is to make it happen. The rpm can be established by putting the motor in the well. When we are pumping mud through the well, it will turn the bit with some speed. Also, by changing the inclination (direction), we will add some amount of rotary speed (top drive) to keep the pipe moving on its own. This number is added to the motor speed to make the total of 350 rpm that is needed for this particular project scenario. In order to meet these requirement, we selected a 6 ¾'' P-150 motor for our design.

This motor will also allow us to fish 6 ¾'' diameter motor into the bit for 8 ¾ '' 7" ID drill bit. To calculate the directional pressure of this motor we used figure 3 from Dr. Bommer's lecture notes on down hole motors and interpolated between 200 gallons per minute (gpm) to 600-

gpm flow rate (Bommer, Down Hole Motor, 2017). To get the flow rate from hole cleaning (Slide 61-62 of Topic 9: Drilling Hydraulics) in inclined holes since our hole is horizontal 90 deg, we need a flow rate to get the rock chips out of the well. Assuming soft rock formation, we take the maximum rate of penetration (ROP) to be 100ft/hr and 90-degree inclination. Using figure 4.2 we get 6.6 transport index (TI) and we plugged that into equation 2 for transport index that is shown below, to calculate the mud flow rate of 580 gpm. Where we used figure 4.1 to get plastic viscosity of 10 cp and yield point of 20, in order to obtain the rheology factor of 0.95 for a mud density of 10 ppg.

Equation 2:

$$TI = \frac{q\rho\,(RF)}{834.5} = \text{ transport index}$$

$$q = \text{ mud flow rate } (\text{gal/min})$$

$$\rho = \text{ mud density } (\text{ppg})$$

$$RF = \text{ rheology factor from Figure 1}$$

$$6.6 = q * 10 * 0.95 / 834.5$$

$$q = 580\ gal/min$$

Figure 3: Directional Pressure of P-150 Motor (Bommer, Down Hole Motor, 2017)

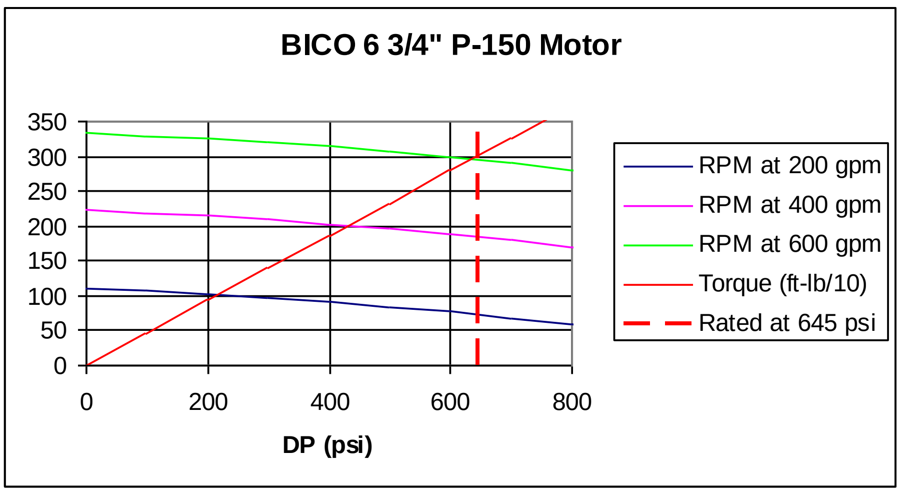


Figure 4.1: Mud Properties (Luo., et. al., "Simple Chart…Requirements", 1994).

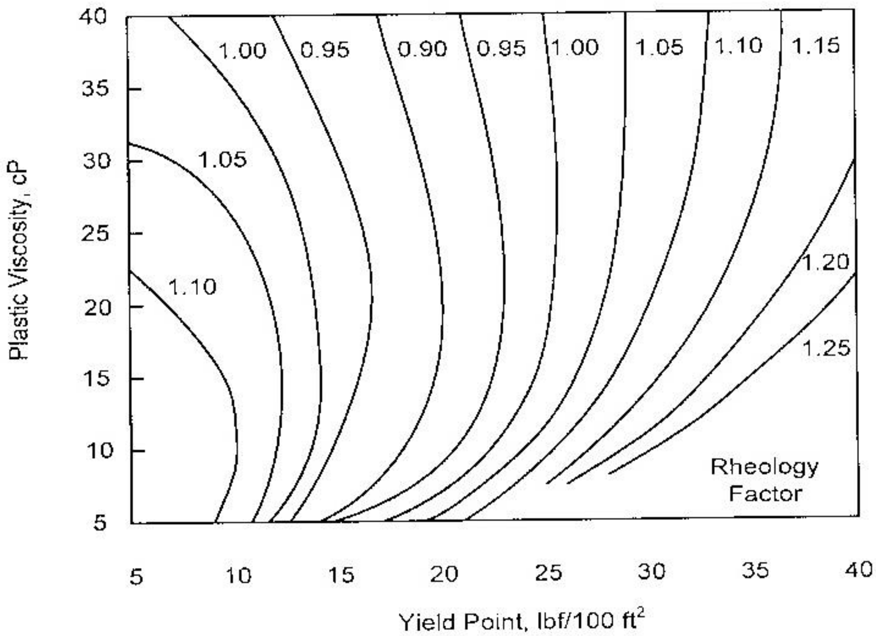
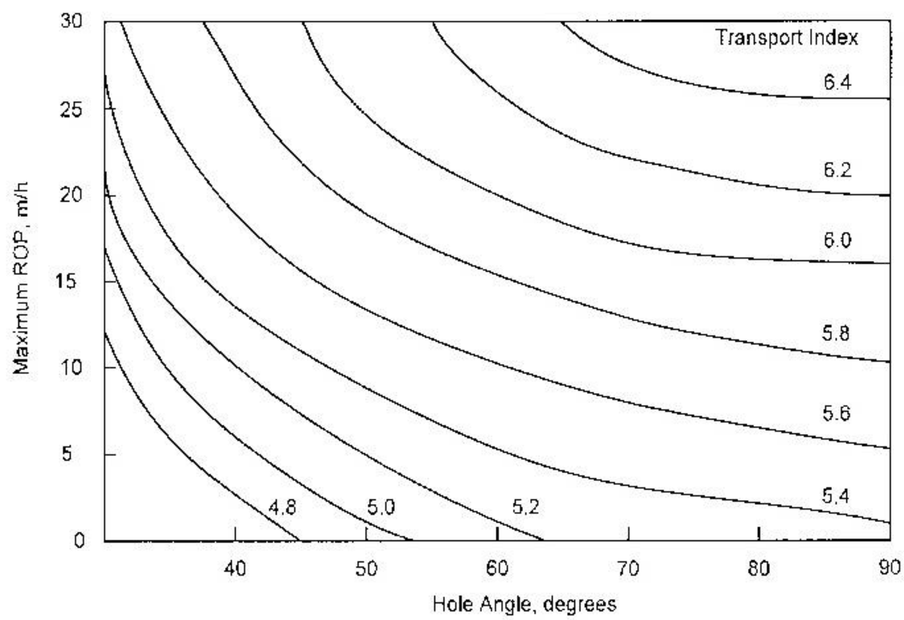
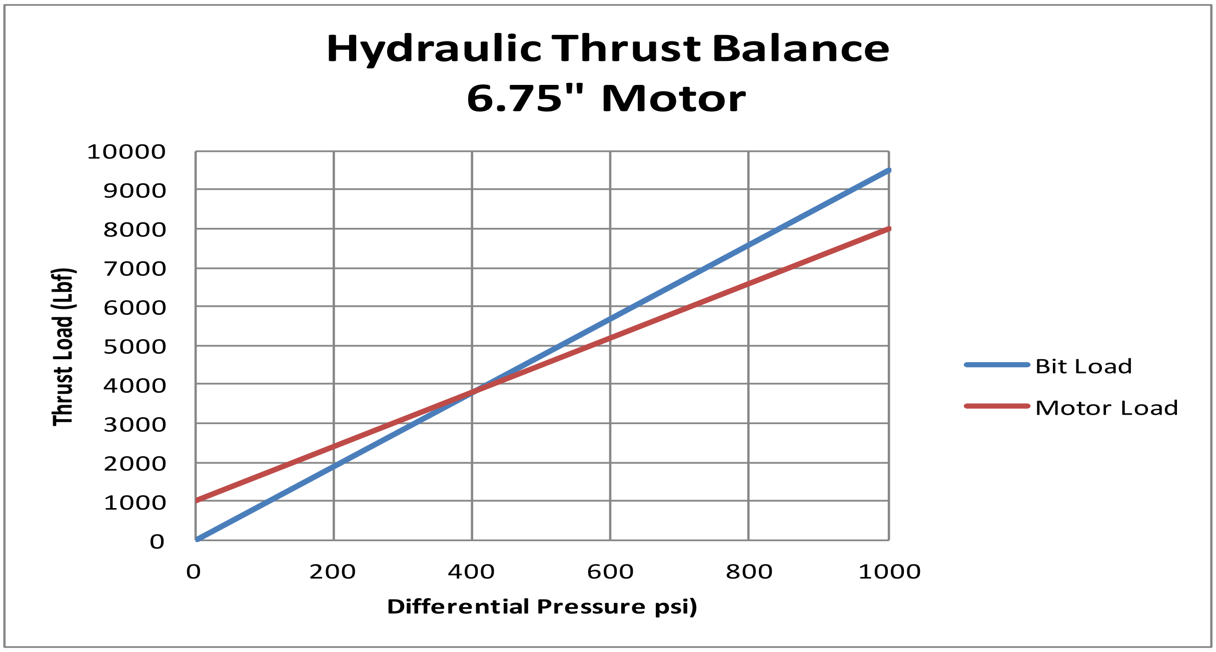


Figure 4.2: Maximum rate of penetration (ROP) that can be maintained with adequate hole cleaning (Luo., et. al., "Simple Chart…Requirements", 1994).



After calculating the flow rate, we need to know how much torque we need from 350 rpm for the motor, as we reserve some rpm for top drive because when we turn top drive it helps to reduce friction and drill at a faster rate. So, we take 300 rpm for motor and reserve 50 rpm for top drive (when we are not slide drilling), making our total revolution to be 350 rpm. The next step is to perform interpolation using motor performance chart (Slide 09 of Topic 10: Down hole motor). And we get a differential pressure of 400 psi as shown in Figure 5.

Figure 5: Hydraulic Thrust Balance for 6.75” Motor (Bommer, Down Hole Motor, 2017)



As the motor starts working when the pump is turned on, the pump is pumping at 580 gpm and must also supply 400 psi of differential pressure drop through the motor.

After taking care of the differential pressure, we need to address, the torque that this motor will put up. For 400 psi of differential pressure, we get almost 200*10 = 2000ft-lbs of torque, which is much more than the needed amount. Therefore it is important that we also take into account life of the motor and make sure that we are not over loading it that what it can handle.

The life of the motor is tied to the thrust bearing. We can get the maximum life out of the thrust bearing if we can run it, essentially at zero/neutral status.
There are two things that are required to balance the thrust bearing.

1) The pressure drop of the 400-psi of differential pressure that we are pumping through motor shows up as force acting across the thrust bearing. This force must be balanced by an equal and opposite force. Which we will supply by putting part of BHA into compression. This bit weight would not show up on the bit, instead it would offset the thrust on the bearing. From figure 5, we get thrust load of approximately 4000 lbf. (extra weight to supply to balance thrust bearing) at 400-psi differential pressure.
2) Since the 4000 lbf. does not show up on the bit and we need to put 4500 lbs. of bit load at the bottom of the hole, which is our required choice of bit to keep drilling, the thrust bearing will be unbalanced again. We will offset this 4500 lbs. force by backing up some pressure from the nozzles in the bit. So, if we want to put 4500 lbs. down we look at the

bit load in figure 5, which comes out to be approximately 450 psi. We then used hydraulics chart as shown in table 2, and opened up the bit nozzles to make the bit nozzle pressure close to 450 psi, which will help keep the thrust bearing balanced.

Table 2: Hydraulics Chart Calculations with Bit Nozzles Sizes.

Newtonian or Bingham Model	**Data**	**Units**
Water Depth	0	ft
Riser ID	16	in
Kill Line ID	3	in
Hole Diameter	8.5	in
Drill Pipe OD	5	in
Drill Pipe ID	4.27	in
Drill Pipe Length	8000	ft
BHA OD	6.75	in
BHA ID	2.5	in
BHA Length	0	ft
Mud weight	10	ppg
Plastic Viscosity	10	cp
Yield Point	20	Lbf/100sqft
Flow Rate	580	gpm
Surface Equipment	479	equiv. ft of DP
Motor Diff Pressure	400.0	psi
Nozzle (32nds)		
14		
15		
15		
15		
15		
0		
Actual Nozzle D	1.035	in
Bit psi with these	438.0	psi

$$F_{thrust} + FwoB = 8500\ lbs.$$

This tells us that we need 8500 lbs. all the way out in the end of the horizontal part of the well.

Drill Pipe

After the selection of motor our next step is to select pipe that connects the horizontal part to the vertical section of the wellbore. We will certainly have 2 parts of the BHA, which leaves us with three options to consider:

1) Drill pipe
2) Heavy Drill Pipe
3) Drill Collars (we also need 1 or 2 nonmagnetic drill collars to insert are instruments)

Considering our three options above to make sure if they will work in this wellbore and keeping in mind that we need to have 8500 lbs. all the way down at the bit and the sliding friction, we first want to calculate the total force on the pipes. Generally, we are rotating entire assembly with top drive, which cuts friction so we can assume that it would not be this bad. However, here we are dealing with worst-case scenario, so the calculated total force on the pipes will allow us to know if the pipes are going to buckle.

Using equation 3 and 4 we calculated the sliding friction and the critical buckling force for the three options. These were calculated based on the drill pipe and drill collars dimensions in the report and are further discussed in the report.

Equation 3:

$$Fs = uLw_{air\ weight}(1 - 0.0153\rho m)$$
$$Fs = \ Sliding\ Friction$$

Equation 4:

$$F_c = 2\sqrt{\frac{EIw\sin a}{12r}}$$
$$F_c = \text{ critical force at the onset of sinusoidal buckling } \left(\text{lb}_\text{f}\right)$$
$$E = \text{ Young's Modulus } \left(30x10^6 \text{ psi for steel}\right)$$
$$I = \text{tube moment of inertia} = \frac{p}{64}\left(OD^4 - ID^4\right)\ \left(\text{in}^4\right)$$
$$w = \text{ buoyed unit pipe weight } \left(\text{lb}_\text{f}/\text{ft}\right)$$
$$a = \text{ hole angle of inclination } (\text{deg})$$
$$r = \text{ clearance between pipe and hole wall} = \left(D_{hole} - OD\right)\ (\text{in})$$
$$OD = \text{ pipe outer diameter } (\text{in})$$
$$ID = \text{ pipe inner diameter } (\text{in})$$
$$D_{hole} = \text{ hole diameter } (\text{in})$$
$$Fc = \ Critical\ buckling\ force$$
$$u = \ friction\ factor$$
$$\alpha = 90deg$$

Drill Pipe: 5” OD, 4.726’’ ID 19.5 ppf (air weight), Grade E

$$Sliding\ Friction\ =\ Fs = (0.2)(6000)19.5\big(1-(10)(0.0153)\big) = 19{,}800\ lbs.$$

$$F_{thrust} + FwoB = 8500lbs$$

$$F_{total} = F_{thrust} + FwoB = 28300lbs.$$

$$Critical\ Buckling =\ Fc = 25{,}300\ \ lbs.$$

The total force pushed is higher than the buckling, which means the drill pipe is likely to buckle.

Heavy Weight Drill Pipe: 5” OD, 3’’ OD, 50.38 ppf (air weight) in 30-foot joints.

Sliding Friction = $Fs = (0.2)(6000)50.38\big(1-(10)(0.0153)\big) = 51{,}200\ lbs.$

$$F_{total} = F_{thrust} + FwoB = 59700\ lbs.$$

$$Criticle\ buckling\ =\ 55{,}123\ lbs.$$

The numbers are close and it will still buckle. So, we are tempted to use as much feet as we can and not let it buckle. Thus, we can calculate how much feet of heavy weight pipe we can use to prevent bucling.

$$55{,}123 = 0.2(L_{HW}50.38(0.847)) + 8500$$

$$L_{HW} = 5463ft$$

$$L_{HW} \approx 5400ft$$

We did not get all the way to our lateral length of 6000 ft. but we can use drill collars for rest of the $\approx\ 600ft$ that is left.

Drill Collars: 20 joints (600’) of 6 ¼” OD x 2.50” ID, 87.35 ppf are available.

Calculation for the combination of Heavy Weight D.P. and Drill Collars

$$Fs\ =\ 0.2\ *\ 0.847\ *\ (5400 * 50.83\ +\ 600\ *\ 87.35)$$

$$Ftotal = 55000 + 8500 = 63500\ lbs.$$

$$Critical\ Buckling\ =\ 146{,}964\ lbs.$$

From these calculations we can clearly see that the heavy weight drill pipe until 5463 ft. and then using drill collars for the last 600 ft. would be our best solution to prevent any buckling.

The problem that still remains is the vertical section of the well that is where the weight is really being transmitted as we are passing through the horizontal. We are essentially forcing the pipe into horizontal to keep sliding and then we hope we still have 8500 lbs. in the end. So, the vertical part of the well is where most critical possibility of the buckling shows up.

For this vertical section, we used an angle of inclination= 1 deg

$$Critical\ Buckling\ for\ Drill\ collars\ =\ 19145\ lbs.$$

We need to overcome 63500 lbs. so the above 1 degree inclination, the critical bucking force for drill collars would not work in this section. However, it does not buckle as long as we make it to horizontal section as fast as we can. It might buckle but it would not last long. When we calculate critical buckling at 10 degrees we get.

$$Critical\ Buckling\ for\ Drill\ collars\ =\ 61241\ lbs.$$

Thus, the transition happens fast it doesn't buckle for long time. By examining all the calculations, we will be using the heavy weight drill pipe: 5" OD and 6 ¼" OD drill collars for our horizontal 6000 ft.

<u>Exercise (3)</u>

We have 8100 ft. of TVD and 6000 ft. of lateral length. We will be eventually perform hydraulic fracturing on this well and to avoid our casing to rupture, we first need to determine right casing and grade for our production casing. For 5.5" OD production casing we will calculate collapse and burst pressures, and tensile load and select casing grade that can overcome these pressures and loading.

Collapse Pressure

We assumed that the internal pressure inside the casing is negligible when calculating the collapse pressure as shown in equation 5.

Equation 5:

$$SF = 1.125$$
$$Pc = SF(TVD)0.052\rho m$$
$$Pc = 1.125(8100)0.052(10) = \ 4739psi$$

Burst Pressure

In calculating burst pressure our internal pressure is higher than the external pressure. The burst load is different on the top of the casing and at the bottom of the casing and we take the burst pressure at the top because that is where it is maximum. For the worst case scenario, we need to consider the maximum burst pressure. As we go shallower in the casing string, the burst pressure requirement increases. This is because the assumption that the internal pressure remains constant throughout the casing string, however the external pressure calculation is different at the top and the lower end of the pipe. External pressure is the function of hydrostatic pressure and at lower depth it is minimum and at higher depth it is maximum.

Burst pressure at the bottom as shown in equation 6, we are taking fresh water outside at the bottom of the well therefore, we do not have any safety factor here because even if we provide enough pressure to the yield point of the pipe, the pipe will change shape but not rupture.

Equation 6:

$$frac\ gradient\ 0.8\ psi/ft$$
$$Pb = 8100(0.8) - 8100(0.433)$$
$$Pb = 2970psi$$

Burst pressure at the top has hydrostatic pressure at zero depth as shown in equation 7.

Equation 7
$Pb = 8100(0.8) - 0(0.433) = 6480\ psi$

Tensile
After studying the casing catalog, we were able to establish that if the 5.5” OD casing overcomes collapse and burst pressure. Then we will have to check for its tensile strength as shown in equation 8.

5.5’’ OD, 17ppf, N-80, LTC.
Minimum yield =80000psi
LTC= longer coupling, 8 round thread
Tensile Strength = over 340000 lbs.
Equation 8:

$$T = 1.8(TVD)W$$
$$T = 1.8(8100)(17)$$
$$T = 247900\ lbs.$$

This would that this pipe is sufficiently strong in tension.

After finding the collapse pressure, burst pressure and the tensile load at each casing seating depth, we were able to determine the grade of the pipe by comparing the calculated values to the manufacturer values of each grades of pipe at the various chosen outer diameter. The production casing will be 5.5’’ OD, 17ppf, N-80, LTC from top to bottom.

Exercise (4)

Cement

Our next step is to cement the casing. We will cement all of the horizontal and vertical section of the wellbore at a minimum of 1000 ft. In the vertical part, as we go shallower, the frac gradient is not same everywhere, so Zobacks equation was used to calculate the frac pressure in equation 9.

Equation 9:

$$Pfrac = (0.32(\nabla\sigma ob - \nabla pore) + pore]TVD$$
$$Pfrac = (0.32(1 - 0.44) + 0.44)8100$$
$$Pfrac = (0.62)(8100)$$
$$Pfrac = 5022psi$$

If we get to this frac pressure, we might fracture the reservoir. We can calculate the height of the cement by using the equation 10:

Equation 10:

$$5022 = 0.052(10)(8100 - h) + 0.052(16.4)h$$
$$Height\ of\ the\ Cement\ Column\ (h) = 2400ft$$

Now we calculate the amount of cement we need by using the volume of the cement equation below to get the number of sacks.

Equation 11:

$$Vcement = 2400(A_{anulus}) + 6000(A_{anulus})$$
$$Aannulus = \frac{\frac{\pi}{4}(8.5^2 - 5.52^2)ft^3}{144} = 0.228\ ft^2$$
$$Vcement = 1914.128\ ft^3$$

We Add 10 to 15% extra for a fear of hole not being perfectly 8.5'' in diameter. After taking that into consideration, we get a the following volume of cement per sack for a Class H neat cement.

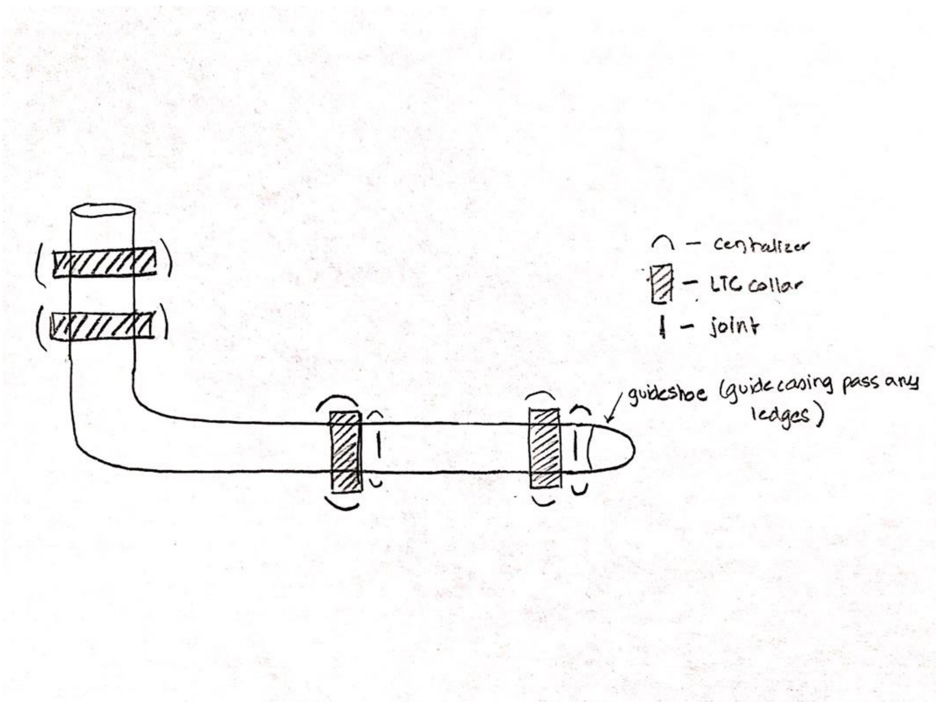
$$Class\ H, 16.4\ lb/gal\ slurry\ yield\ =\ 1.06\ ft^3/sack$$
$$Number\ of\ Sacks =\ 1914.128\frac{ft^3}{1.06\frac{ft^3}{sack}} = 1806\ Sacks$$

Hardware

Finally, when we run the casing we have hardware associated with it. The guide shoe is placed at the end of the casing to guide the casing pass any ledges. When we cement the casing, we are very interested in putting casing all around it. We need some equipment to help the casing hold it from the bore hole and we would not be able to circulate cement. Thus, we need

centralizers. We put two centralizers, one on joint and another on collars of each pipe. Also, we hold centralizers with lock ring to secure centralizers that are in the middle. Since we have 2400 ft. of cement in vertical, we can put one centralizer around each collar.
In the horizontal part since we have 6000 ft. of 30 ft. joints of casing, it would yield to 2 centralizers per joint like stated above. Therefore, we would have total of 200 joints with 2 centralizers leading to a total of 400 centralizers in the horizontal part. While in the vertical section we will have 30 joints with 1 centralizer, leading to a total of 80 centralizers. Combining the vertical and horizontal section, we will be using approximately 480 centralizers.

Figure 6: Hardware Attached at the End of the Well



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