PGE 362
PRODUCTION TECHNOLOGY AND DESIGN

MIDTERM REPORT

THE BAKKEN

Rock Type: Organic rich black shale.
TVD of 10,930 feet
Porosity: 30%
Absolute Horizontal Permeability: 50 n
Darcy to air.
BHT: 250 deg F
Initial BHP: 5,480 psia
Reservoir Fluid: Under saturated oil.
Oil gravity: 30 deg API
Bubble Point: estimated to be 4,550 psia

Upper Bakken

Middle Bakken

Lower Bakken

Professor: Dr. Paul Bommer

Prepared by:
Maruchet Ponghunsa(mp43772)
Ahad Momin(am823437)

Table of Contents

Introduction	3
Problem Statement	3
Executive Summary	7
Casing and Tubing Design for Frac Jobs	8
Packers	9
Fracturing Fluid (Includes Parts of the Fracturing Design	15
Completion Fluids	19
Backup Plans	23
Perforations	24
Frac Hit Defense	27
Flow Back Mechanism	28
Prevention In Case of Issues	29
Fracturing Equipment	30
Flow Rates (oil/gas/water) and Descision For Stages	31
Fracturing Cost Estimation	35
Flow Assusrance and Issues with Fluids	38
Corrosion	39
Well Head Design	41
Valves	43
Choke	44
Facilities	45
Pipeline Design	53
Scaling	64
Artificial Lift	67
Recompletion	69
Plugging and Abandoning (P & A)	72
References	73

Introduction

This project covers the plan for the completion and production of an organic rich black shale horizontal oil well in Bakken, North Dakota. It also covers many of the industry standards and safety regulation that are associated with production and completions of an oil and gas well through the calculations and design processes such as perforations, casing and tubing and style and size of fracture jobs etc.

Problem Statement

The Bakken is one of the world's great hydrocarbon producing formation, with a hydrocarbon producing history stretching more than 70 years. The Bakken shale play represents the fullest application of modern completions technologies. The Middle Bakken and Three Forks reservoirs are tight, naturally fractured sandstones that respond exceptionally well to long laterals and multi-stage fracture stimulation (Berman, 2017). To comprehend and understand the method of completion of a horizontal well an organic rich black shale, one must look at and analyze the formation in which he is planning to produce. Figure 3 shows the Bakken formation is divided into three sections; upper, lower and middle Bakken. As shown in figure 1 and 2, the project well is already drilled in Bakken, North Dakota and needs a best cost effective completion method to make it produce.

In figure 2, a completion engineer can see that the upper Bakken formation starts at 10901 feet (ft.) and the intersection with the middle Bakken occurs at a TVD of 10,930 feet. The horizontal lateral was drilled to follow the dip of the formation to a final TVD of 10,990 feet at a total MD of 20,500 feet. Using the directional survey data in canvas, it is concluded that the path of the well is to the south and in a down dip direction. This means the end or toe of the lateral is deeper than the beginning or heel of the lateral. The overall lateral length is 9900 ft.

Fig 1: Project Drilled

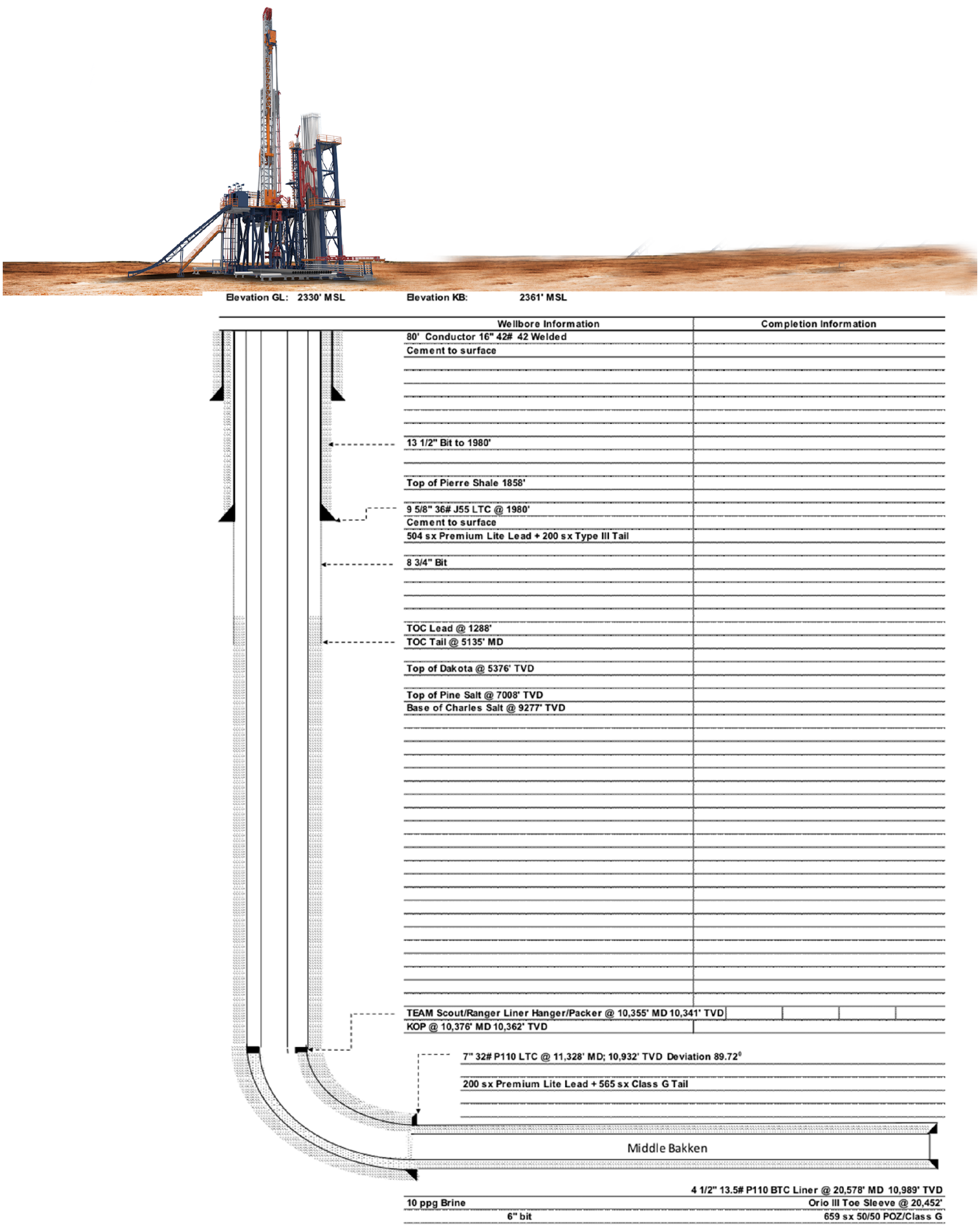
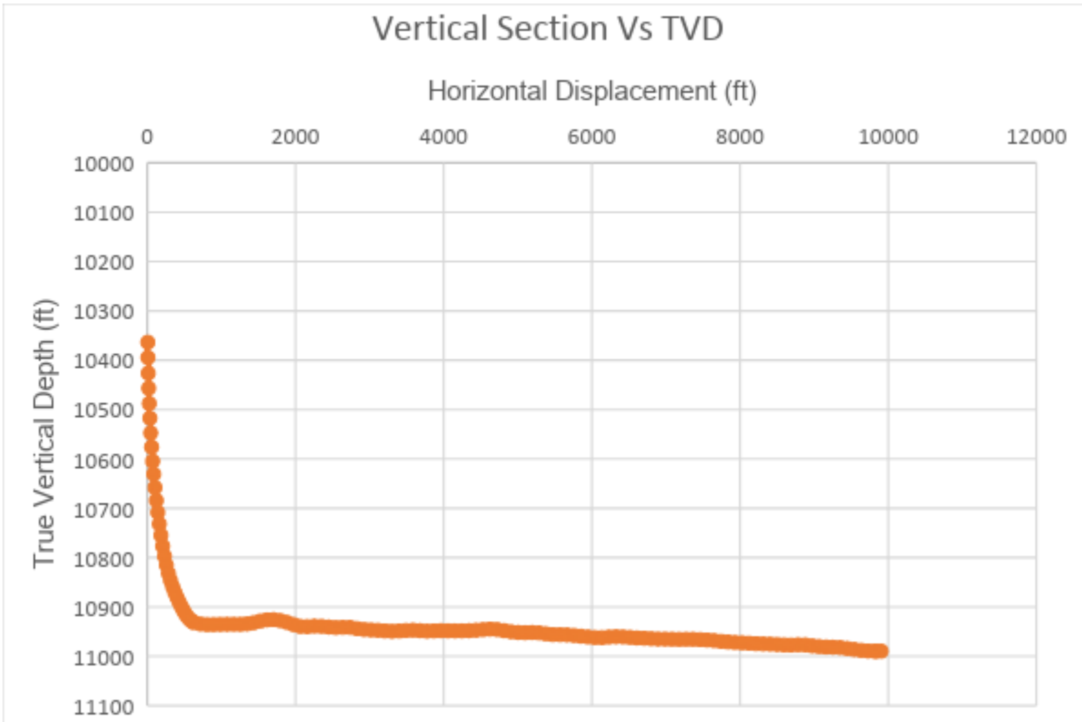
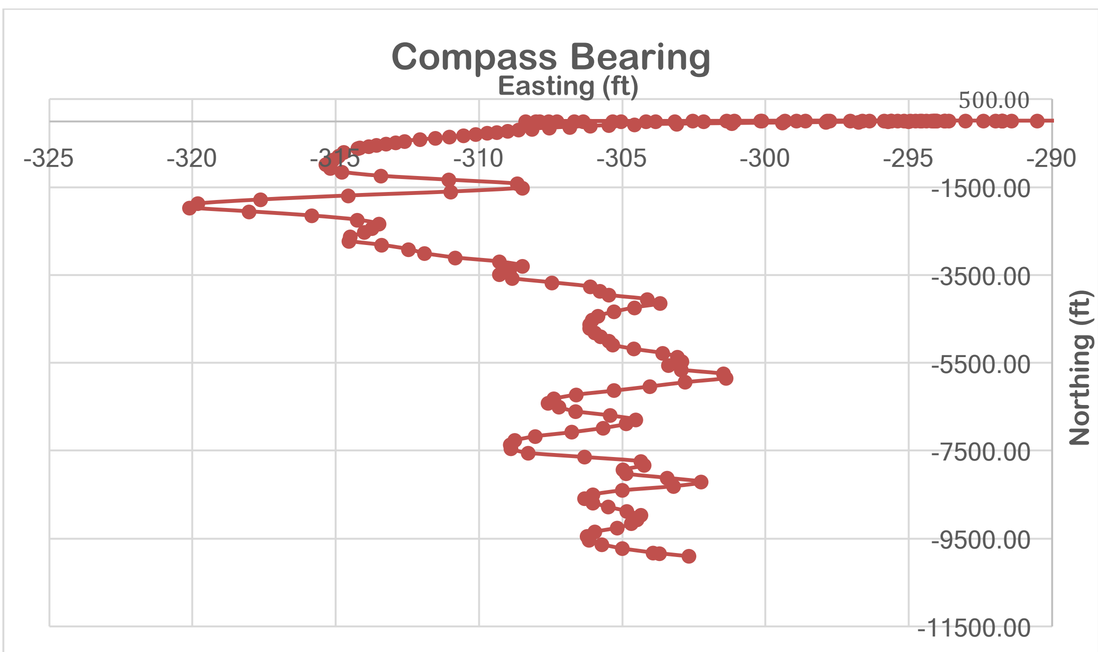


Fig 2: Directional Survey





The best estimated description of the reservoir is organic rich black shale and contains under saturated oil at a reservoir pressure that is above the bubble point pressure of 4,550 psia. It has a porosity of 30%, absolute horizontal permeability of 50 Nano-Darcy (nd) to air. It has a bottom hole temperature of 250

°F and initial bottom hole flowing pressure of 5,480 psia. The mud weight used during drilling was 10 ppg and this was thought to be about 0.5 ppg above pore pressure. The geological record of the formation is given in table 1.1 below.

Table 1.1: Geological Record

Formation	Depth TVD (ft)	Remarks
Pierre Shale	1860	base of Foxhills usable water
Mowry	5013	
Dakota	5376	
Pine Salt Top	7008	
Pine Salt Base	7088	
Opeche Salt Top	7258	
Opeche Salt Base	7356	
Minnelusa	7573	possible oil/gas
Charles Salt Top	8614	
Charles Salt Base	9277	
Mission Canyon	9485	possible oil/gas
Scallion	10892	possible oil/gas
Upper Bakken Shale	10901	oil/gas
Lower Bakken Shale	10960	oil/gas

Furthermore, the liner hanger has a liner top packer with a 25 foot polished bore receptacle (PBR). The PBR dimensions are: 5.920” OD, 4.276” ID, and 25.81 feet long. The seals to use inside the PBR are 4.276” OD, 3.920” ID, with a length to be determined up to 25 feet. Using this information, a completions and production program is designed, that is intended to perforate and fracture the nano-darcy permeability well, which is actually considered to be zero, while improving the flow rate. The midterm report will discuss perforation geometry based on skin calculations, casing or tubing design for the fracture jobs, style and size of fracture jobs, flow back after fracturing, completion fluids, fracture hit defense, production tubing and packer installation. This is done so to establish a best and working completions program that is safe, usable, cost-effective and improves flow rate in this crazy low permeability.

Executive Summary

The purpose of this report is to determine the completion processes of the Bakken Shale well in North Dakota. Accordingly, this report discusses the whole production process of this Bakken Well, from ensuring that the casings are strong enough to recompletion and well plugging.

At the initial production process, production tubing is not necessary for the project. However, when the artificial lift system is installed, which will be gas lift for this project, the production tubing of 2 7/8" will be necessary. The packers were installed in order to aid the 7" intermediate casing, since its burst pressure tolerance is very close to the breakdown pressure, which could lead to some problems during fracturing. The lateral section of this well is 9,205 feet long. The current fracturing plan will divide the length into 30 stages for fracturing, and each stage will have 5 clusters. In terms of perforating, the perforating gun will shoot 6 shots of perforation per foot in order to maximize recovery. Thus, 55,230 perforations will be done in total. 25,420 gallons of completion fluids will be pumped with the efficiency of 0.23. The estimated cost for the fracturing design is approximately $2 million USD.

Ultimately, the flow back procedure was set and is discussed in this report in order to initiate the production stage. The expected production, calculated using the Prats equation, will be 750 STB/D for oil and water, and 675 STB/D for gas. As a result of the flow rate, the sell pipes are designed. The sell pipe for the oil will be 6.625" OD, 18.99 ppf, STD. The gas sell pipe will be 5.563" OD, 20.8 ppf, XS. The sell pipe for produced water will be 7.625" OD, 23.57 ppf, STD.

In terms of the facilities, they are designed to separate oil, gas, and water in order to sell the oil and gas separately. Produced water will be sold to agents who need water for water injection. Oil and gas will be transported into the oil pipe and the gas pipe to the buyers accordingly.

After the well is depleted, there is a good opportunity for recompletion. The recompletion can add an additional profit ranging from $1 to $3 million USD. Thus, it is very desirable to do recompletion. Finally, the well will be plugged and abandoned properly due to the regulations.

Casing and Tubing Design for Facture Jobs

Designing a proper production casing string is extremely important in any type of oil and gas well design, since it ensures that the shallow formations are protected from the high pressures of the deeper zones. Casing being one of the most fundamental parts of a well design and important part of drilling and completions, it needs to be perfectly designed, and cemented before the production tubing is ran and well is completed. Before starting the completion method for the project well, it necessary to see and review if the 4.5-inch (production liner) and 7 inch P110 casing pipes are ready to fracture. It is highly crucial to decide if the casing that we intend to fracture handles the fracture pressures or not. If not that it can cause a great damage to the well and the entire investment could go to waste. Thus, using the casing catalog and table 7.6 for the applied drilling textbook, the important specifications and limitation of the 4.5 and 7 inch OD P110 Buttress thread pipe can be reviewed.

Casing Specifications:

Table 1.2 shows that specification of the pipes that we intend to fracture. The data is pulled from table 7.7 for applied drilling textbook and frac mud weight is calculated using zobacks equation.

$$\nabla P_{frac} = 0.32 * (\nabla P_{OB} - \nabla P_{pore}) + \nabla P_{pore}$$

$$MWfrac = \nabla P_{frac}/0.052$$

Table 1.2 Casings specifications

Casing type	Set Depth TVD (ft)	OD (inch)	ID (inch)	Coupling Type	Coupling Diameter (inch)	Weight Density (lb/ft)	MudWeight(ppg)	Frac Mud Weight	Grade
Production (BTC Liner)	10989	4.5	3.92	Butress	5	13.5	10	12.61	P110
Casing 7"	10932	7	6.094	Long Thread	7.656	32	10	12.61	P110

Casing Limitations:

Table 1.3: Casing Limitations

Casing type	Body Yield Strength (lb)	Internal Yield Presure (psi)	Collapse Resistance (psi)	Joint Strength (lbs)
Production (BTC Liner)	422000	12410	10680	443000
Casing 7"	1025000	9520	10780	897000

Casing type	Collapse pressure	Burst Pressure	Tensile loading
Production (BTC Liner)	6107.13675	7207.90488	224775
Casing 7"	6075.459	7170.51744	652492.8

By comparing the calculated burst, collapse and tensile loading, it is clear that the pipe is good to start the frac jobs. The next step is to calculate frac pressures required to design and complete this well. The fracture pressures are then calculated using the formulas from the lecture.

Table 1.3: Casing Limitations

Casing type	Vonmises	Sv (psi)	Smin	Smax	Pb	Pfrac
Production (BTC Liner)	0.25	10989	6348.861866	8668.930933	9589.2268	7282.044

Examining the table, the break down pressure is less than the specifications for the 4.5 inches production liner. A new frac string is needed to be inserted in the 7 inch to protect it from the fracture pressures, before the completion processes is be proceeded.

Packers

New Frac String and Packer Installation

Packers are a mechanical engineered device that are used to isolate parts of the well. It mostly consists of an external slips that engage against the casing holding the packer in place, external elastic elements that extrude against the casing and form the hydraulic seal that isolates a part of the well and a connector to attach the tubing string (ppt packers). Packers serve a lot of purpose such as protecting casing above from pressure and temperature fluctuations and isolate casing from high pressure fracture jobs.

Table 2.1: 7-inch casing

Casing type	Internal Yield Pressure (psi)	Break down Pressure (Pb)	Smax	Pfrac
Casing 7"	9520	9589.23	8668.930933	7282.044

A high pressure frac job inside the 7-inch will be conducted and if it is noticed, the table 2.1 shows that the breakdown pressure of the fracture job that we intend to do is higher than the exposed 7-inch casing's internal yield resistance. It is highly important that a decision should be made here since fracture job inside the 7-inch casing could accidently rupture it, the well will be ruined and all the investment will be thrown away (Bommer). The idea or a way required to protect the 7-inch casing from the high pressure fracture, that is normally done in the industry is using an another liner 4.5 inch 13.5 P110 (BTC), Table 2.2 shows that the internal resistance of 4.5inch temporary string is higher than the fracture pressures required to do the frac job.

Table 2.2: 4.5 Inch P110 (BTC) casing specification

Casing type	Temporary frac string 4.5 inch P110 13.5 (BTC Liner)
Internal Yield Pressure (psi)	12410
Break down Pressure (Pb)	9589.23
Smax	8668.930933
Pfrac	7282.044

For the well to safely frac it, it is appropriate to use the 4.5 inch P110 13.5 lb. /ft. to protect the 7-inch casing from high pressure frac job. This temporary casing will be connected to the liner top of the 4.5 inch of the production casing that will be fractured. The real question comes that how should be this high strength temporary frac string must be connected to the production liner? That's where the linear top packer comes in. Liner top packers provide a mechanical seal at the top of the liner and provide the same functionality as a setting sleeve. The spreadsheet from the canvas will be used to make a decision that whether the liner top packer will suit the purposes or not.

Forces on Packer:

Every packer comes with a pressure differential rating (the pressure differential that the packer should seal against) that must not be exceeded. It's a responsibility of a completion engineer to figure out what kind of packer should be suitable for the job. This is accomplished by keeping in mind all the forces acting on packer and then comparing all values with its rating. The forces on packers are applied by a combination of:

Different pressure above and below the packer (Differential Pressure), compression force caused by tubing weight slacked off on top, compression force due to heating and expanding the tubing, tensile force causes by pulling the tubing up against the packer, tensile force due to cooling and contracting the tubing and tensile force due to pressure increase inside the tubing (Packers, ppt 9).

Fig 33 shows latch less permanent packers, which means that the tubing can move in and out, it's not secured. If the tubing pressure is increased during the job, the tubing will be pushed out of the packer, pressure in the tubing will cause the tubing to shrink it up. The higher pressure will also cause the metal tubing to expanding, causing ballooning. However as long as the seal stays inside the seal bore its good, the tube is not shrinking. If there is a latch, the forces will be building up on the latch. Using the hooks law the force on the tube the shrinkage represents can be calculated (Bommer). The force that causes the shrinkage will try to break the latch, so as long as it doesn't exceed the strength of the latch, it's perfect. If the cool fluid is injected in the hotter well, then it will slowly cool of the metal tubing causing contraction trying to shrinkage even more. Depending on how much cooling to provide it will be a fairly big change in length of the tubing and if latched all these shrinkage forces will be on the latch. However, in this well we will consider packer without a latch. **Note** that the positive elongation is down and negative is upwards (shrinking).

To address the question of what is the differential pressure across the packer during the fracturing job and how many feet of seals are required to insure the seals do not shrink out of the seal bore? The following equations, data and dimension in Table 2.3 and 2.4 would be used to calculate the forces with the help of excel sheet on the canvas.

Fig 3: Length changes Possible

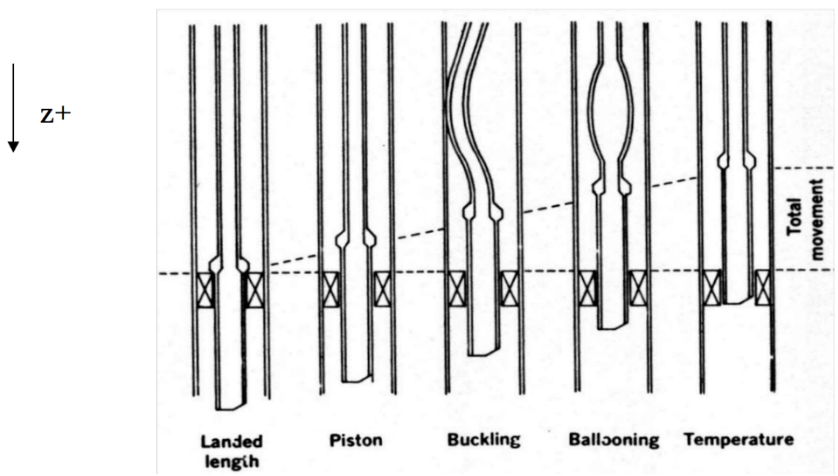


Table 2.3: Data Used in Calculating Forces on the Packer

• A 10341 TVD and 10344 MD to the packer with a static BHT of 250 deg F is to have a large fracture stimulation job with injected water at 80 deg F.
• The maximum treating pressure (redline pressure) 9657 psi at the surface with fracturing fluid having a fluid gradient of 0.208 psi/ft (4 lb/gal). Proppant concentration
• The fluid above the packer is 10 ppg brine (well full of completion fluid) and an extra additional 1000 psi can be applied to the annulus during the job as back up pressure.

- 9,000lb of tubing weight is applied to the top of the locator. This is called the “slack off” force. (tubing goes into the packer, when collar reaches the packer, a 9000 lbs is applied pushing down on the top of the packer)

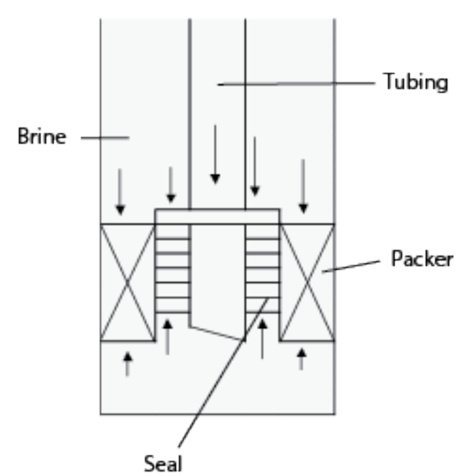
Table 2.4: Dimensions

Data	Dimensions
Packer Rating	15000 psi
The tubing	4.5”, 13.5 ppf, P110, Buttress (3.92” ID). Minimum Yield 110,000
The packer locator	OD (connection) is assumed to be the same as the packer bore.
The packer (PBR)	5.920” OD, 4.276” ID”.
The seal metal OD	4.2” OD.
The seal metal ID	3.92”
The casing ID	6.094”
Latch Yield Force	144,000

Differential Pressure:

As long as the pressure above – pressure below the packer is below the pressure differential rating of the packer the packer is good.

Fig 4: Fa and Fb schematic



$p_a =$ pressure above the packer (psi)

$p_{sa} =$ surface pressure in the annulus (psi)

$D =$ packer true vertical depth (ft)

$p_b =$ pressure below the packer (psi) /ft)

$p_s =$ surface pressure in the tubing (psi)

$D =$ packer true vertical depth (ft)

$FG =$ pressure gradient of the fluid in the tubing (psi/ft)

Next, forces on the seals are computed, also known as tubing movement calculation to see how much the seal moves. The following forces above and below are calculated using the following formulas.

$$F_a = p_a \frac{\pi}{4}\left(OD_b^2 - OD_s^2\right) + F_{SO}$$

F_a = force acting on the seals from above (lb_f)

p_a = pressure above the packer (psi)

$$F_b = -\left[p_b \frac{\pi}{4}\left(OD_b^2 - ID_s^2\right)\right]$$

F_b = force acting on the seals from below (lb_f)

p_b = pressure below the packer (psi)

OD_b =

ID_s =

$$F_{bal} = 0.6\frac{\pi}{4}\left(\Delta p_a (OD)^2 - \Delta p_b (ID)^2\right)$$

F_{bal} = force caused by tubing ballooning (lb_f)

Δp_a = pressure change in the annulus (psi)

Δp_b = pressure change inside the tubing (psi)

OD = tubing outer diameter (in)

ID = tubing internal diameter (in)

The ballooning force due to the pressure change in inside and outside of the tubing is also computed. The pressure change always occurs when the packers are place in and the average hydrostatic pressure in the tubing and in the annulus is taken.

$$\Delta p_b = \Delta p_{STP} + 0.052\frac{D}{2}\Delta\rho_t$$

$$\Delta p_a = \Delta p_{SAP} + 0.052\frac{D}{2}\Delta\rho_a$$

Δp_a = average pressure change in the annulus (psi)

Δp_b = average pressure change inside the tubing (psi)

D = true vertical depth to the packer (ft)

Δp_{STP} = change in tubing surface pressure (psi)

Δp_{SAP} = change in annulus surface pressure (psi)

$\Delta\rho_t$ = change in the density of the fluid inside the tubing (lbm/gal)

$\Delta\rho_a$ = change in the density of the fluid inside the annulus (lbm/gal)

The contacting force due to cooling is calculated that acts to pull the seals out of the packer.

$$F_T = E\beta(\Delta T)A_t$$

$$F_T = 30x10^6\left(6.9x10^{-6}\right)\Delta T\frac{\pi}{4}\left(OD^2 - ID^2\right)$$

$$F_T = 162.573\Delta T\left(OD^2 - ID^2\right)$$

F_T = force acting on the seals from temperature change (lb_f)

β = linear thermal expansion coeff. (in/in/deg F)=6.9x10^{-6} in/in/deg F for steel

$\Delta T = T_2 - T_1$ = temperature change (deg F)

E = Young's Modulus (psi) = 30x10^6 for steel

OD = OD of the tubing (in)

ID = ID of the tubing (in)

All the forces are now summed and the length moved up caused by the force is evaluated using the Hooke's Law.

$$\sum F = F_b + F_a + F_{bal} + F_T$$

$$\frac{\sum F}{A_t} = \frac{\Delta L}{MD} E$$

$$\Delta L = \frac{\sum F}{\frac{\pi}{4}\left(OD^2 - ID^2\right)} \frac{MD}{30x10^6}$$

$\Delta L =$ change in length (ft)

$MD =$ measured depth to the packer (ft)

Lastly, we consider an extra tubing contraction called buckling. When the tubing is moving up due to all the force discussed above. It will buckle into the shape of helix. This buckling force can be computed using lubinski's equation.

$$\Delta L_{buc} = \frac{\Delta r^2 A_p^2}{8EI} \frac{\left(\Delta p_a - \Delta p_b\right)^2}{W_s + W_i - W_a}$$

$\Delta L_{buc} =$ tubing shortening due to buckling (in)

$\Delta r =$ radial clearance between the tubing and the casing (in)

$A_p = \frac{\pi}{4}(OD_b)^2 =$ packer bore area $\left(\text{in}^2\right)$

$E =$ Youngs Modulus $= 30x10^6$ psi for steel

$I = \frac{\pi}{64}\left(OD^4 - ID^4\right) =$ tubing moment of inertia $\left(\text{in}^4\right)$

$W_s =$ tubing unit weight (lb/inch)

$W_i =$ unit weight of fluid acting on the inside of the tubing (lb/inch)

$W_a =$ unit weight of fluid acting on the outside of the tubing (lb/inch)

Using the spreadsheet of all this formulas, the data is inputted and all the forces are calculated shown in table 2.5.

Table 2.5: Results from Packer Calculator

Results			
Pressure Differential Across Packer		4,446	psi
Packer Pressure Status		OK	
Net Piston Force		-15,802.9	Lbf
Tubing Ballooning Force		-28,278.8	Lbf
Temperature Change Force		-134,970.1	Lbf
Seal Movement		-16.21857808	ft
Pitch of Buckle		288.5	in
Will Buckle Be Permanent		no	
Force Against Latch		0	Lbf
Force at Top of Tubing		139,793	Lbf
Will Latch Fail?	no latch	0.00	safety factor
Will Tubing Fail at Top?	no	3.02	safety factor

The differential pressure across the packer during the fracturing job is 4,269, which is lower than the 15000 psi rating. Thus, the packer will not leak and is perfectly suitable for the job. The seal movement is upwards is 16.11764 ft. The PBR seal has a length up to 25ft. Hence, the seal will not shrink out of the seal bore. Overall, the liner top packer is beautiful and works great for connecting 4.5-inch buttress frac string to the 4.5 production casing. Also, tubing will not fail at the top. The packer design is ready.

Fracturing Fluid (Include Parts of the Fracturing Design)

In order to perform the fracturing job, the first thing to do is to specify the fracturing fluid. In order to maximize the potential of this fracturing process, it is desirable to use the "**slick water**" fluid. One might argue that using the "cross linked gel" is better. This is because the cross-linked can be set to respond to specific time and temperature. Thus, an engineer can program the fluid so that is will yield a huge increase in viscosity at the bottom of the well, rather than anywhere along the way down to the bottom of the well bore. However, the slick water is generally a lot cheaper than the cross-linked gel. Additionally, since it is less viscous, the slick water will work better at higher flow rates and would not shear, as opposed to the cross-linked gel. The required horse power is also lower for the slick water. Thus, it is best for this project to use the slick water as the fracturing fluid.

The base fluid for this slick water can vary depending on the purpose and limiting conditions of the project. However, in order to minimize the environmental impact and the cost, an engineer would choose water as the base fluid. In addition, an engineer can further manipulate the fluid so that it can control filtration more effectively. She can also add substances so as to improve recovery, and to extend the lifespan of the fluid.

In this project, the PKN is chosen for considering the fracturing process. This is because the PKN model is the best model for determining the fracture that is propagating with one direction confined. In this case, height is confined because the formation is the "Middle Bakken." According to the Bakken study, the confined height is 100 feet, since the Upper and Lower Bakken act as barriers for the fracture. Thus, an engineer can proceed to pick the proppant type. After considering several options, an engineer would choose sand as proppant for this project, due to its cost and availability. Then, the mesh size of 40/60 Northern sand, or 0.0098 to 0.017 inch in diameter, is picked since the size suits the fracturing project, since it is commonly used to yield large diameter fractures, but not too large to fit inside the fractures. Prior to the 40/60 mesh proppant, it is also a good design to inject the 100 mesh proppant in order to keep the tip of the fracture opened. The reason that the 40/60 Northern sand is picked is that it is relatively cheap, and it is able to fit inside the fracture. If instead the 20/40 mesh was picked, the diameter of 0.0993 inches would not allow it to fit inside the fracture width (refer to the results on the Frac Data & Result Figure), which would result in a screen out.

Table 3.1: Proppant Specs

Model	PKN	
proppant type	40/60 mesh sand	
diameter	0.017	in
injection rate	40	bbl/min

Then, an engineer would refer back to the Bakken study in order to determine the Young's Modulus of the formation, along with the Poisson Ratio, the height of the fracture is limited at 60 feet due to the formation. Then, the fracture half-length is approximated in order to maximize the recovery yield without interrupting any nearby well.

Table 3.2: Variables

Young's Modulus Range	4.35 to 6.09	E6 psi
Picked Young's Modulus	5200000	psi
Poisson's Ratio	0.25	

Fracture Half length	600	ft
Height	100	ft

Note: The height of 100 feet, instead of net pay height of 60 feet, will be justified later in this report.

The fracturing width needs to be at least three times of the proppant diameter in order that the proppant can within the fracture. Thus, the fracturing width (ŵ) is determined to be 0.051 inches. The fluid viscosity is then calculated by the following formula:

$$\mu_a = \left(\frac{\overline{w}}{0.39(0.6)} \right)^4 \frac{E}{q(1-\nu^2)x_f}$$

average width (3 times proppant diameter)	0.051	in
fluid viscosity	2	cP

The friction pressure is also calculated with the following formula:

$$\Delta p_{fruction} = 0.0168 \left[\frac{\mu_a q E^3 x_f}{H^4 (1-\nu^2)^3} \right]^{0.25}$$

Friction Pressure	278.76	psi

The next step is to calculate the injection pressure needed, since it determines the pump power required for the project. The injection pressure is calculated from the following formulas:

$$p_{inject} = p_{farfield} + p_{fracfric} + p_{pipefric} - \frac{7.48}{144}\rho L \sin\theta$$

When P_2 is the far field pressure,

$$p_2 = \text{ fracture creation pressure } (\text{psi})$$

$$p_2 = \frac{\nu}{(1-\nu)}\left(\sigma_v - p_{pore}\right) + p_{pore}$$

Table 3.3: Data for Calculating Fluid Parameters

TVD	10989	feet
Pipe Friction	100	psi/100 ft
Pore Pressure Gradients (9.5 ppg)	0.494	psi/ft
Fracturing Fluid Density (Water Based)	62.4	lbm/cubic ft
Fluid Viscosity	1.85	cP
Injection Rate	40	bbl/min

Far Field Pressure	7282.044	psi
Fracture Friction Pressure	278.7555556	psi
Pipe Friction	1500	psi
Injection Pressure	4305.889781	psi

Ultimately, the hydraulic horsepower required for pumping is calculated through,

$$HHP = \frac{q_i(p_1)}{40}$$

Hydraulic Horsepower	5382.362226	hp

Note: This value is slightly higher than what was calculated from the Frac Data and Results Spreadsheet (shown later in this section). However, in order to prepare for the worst case scenario, it is preferable to pick 5382 as the required horse power.

Completion Fluids

In order to complete the fracturing process, several completion fluids are required. Such fluids can be discussed as followed,

1. Pretreatment

Pretreatment fluid is pumped down with the intention to learn something from the well. For example, the fluid can verify the fracture gradient, injection rate, leak off pressure, closure pressure, and perforation near wellbore.

2. Pad

Pad is a sacrificial volume that is pumped to break the rock and get the fracture to move. Pad volume will create a space for proppants to reside in afterwards. Pad volume was calculated using the utilities package, as the following

INPUT DATA		
Tubing or Casing ID	3.92	inch
TVD to Top of Pay	10989	feet
MD to Pay	20194	feet
Net Pay Thickenss	100	feet
Pumping Rate	40	bbl/min
Required Fracture Half Length	600	feet
Tolerated Frac Height Above Pay	4	feet
Tolerated Frac Height Below Pay	1	feet
Reservoir Porosity	0.3	
Maximum Prop Concentration	4	ppg
Prop Density	165	lbm/cuft
Prop Size	4060	
Sand 165 lb/cuft, bauxite 230 lb/cuft		
Pay Sand Poisson's Ratio	0.25	
Zone Above Poisson's Ratio	0.3	
Zone Below Poisson's Ratio	0.35	
Young's Modulus (E)	5200000	psi
Biot's Poroelastic Constant	0.742	
Fracture Toughness	1000	psi/sqrt(inch)
Frac Gradient	0.65572	psi/ft
Overburden Gradient	1	psi/ft
Pore Pressure Gradient	0.5	psi/ft
Base Frac Fluid Gradient	0.44	psi/ft
Annulus Fluid Gradient	0.433	psi/ft
Annulus Back Up Pressure	1000	psi
Tube burst at 100%	12410	psi
Frac Fluid Data from the lab		
Flow behavior Index (n)	1	
Consistency Index (K)	0.000048	lbf-sec^n/ft^2
Leak Off Coefficient (Cl)	0.0019	ft/sqrt(min)
Friction Coefficient for q & D	89.3	psi/1000'
Fracture Entry Friction	0	psi
Well Bore Diameter	6	inches
Formation Permeabilty	0.00005	md
Drainage Radius	660	feet
Pre frac skin	-1.34868	

Fig 5: Inputs for the Frac data and Results spreadsheet.

CALCULATED RESULTS					
Total Fluid Volume			25420	gals	
Pad Volume			16020	gals	
Fluid Efficiency			0.23		
Percent Pad			63.02	%	
Hydraulic Frac width at the well bore			0.12	inches	
Average Hydraulic Frac Width			0.07	inches	
Average Propped Frac Width			0.02	inches	
Avg prop width must be less than avg hydraulic width					
Net Pressure to extend to required length			135	psi	Minimized
Use SOLVER to estimate up/down growth					Error Term
Net Pressure to grow up to limit			135	psi	0
Net Pressure to grow down to limit			135	psi	0
					0
Pumping Time			15	minutes	
Required Proppant			23066	lbs	
Prop Surface Concentration			0.18	Lb/sqft	
Average Prop Density			2	ppg	
Fracture Conductivity			205	md-ft	
Fracture Stimulation Effect (skin)			-7.47		
Folds of Increase in Production			16.16		
Minimum Absolute Horizontal Stress Profile					
Upper Layer			7040	psi	
Pay Zone			6411	psi	
Lower Layer			7870	psi	
	Anticipated Surface Treating Pressures				actual
	Pad		4172	psi	
	0.8	ppg	3927	psi	
	1.6	ppg	3701	psi	
	2.4	ppg	3491	psi	
	3.2	ppg	3296	psi	
	4	ppg	3114	psi	
	Flush		4199	psi	
RED LINE at 80% of BURST			9657	psi	
at maximum prop concetration					
Required Horsepower			4117	Hp	

Fig 6: Results for fracturing.

Note: The height of the middle Bakken formation is around 60 feet. When setting 60 feet as the net pay period, the fracture grows 4 feet above the pay zone, which will break through into the Upper Bakken zone. Thus, the net pay thickness is not limited to 60 feet any more. An engineer might decide that the net pay thickness is 100 feet in order to balance other variables such as the pumping time.

Thus, required pad volume is 16,020 gallons, and the required pumping time is around 15 minutes. In addition, fluid efficiency is 0.23.

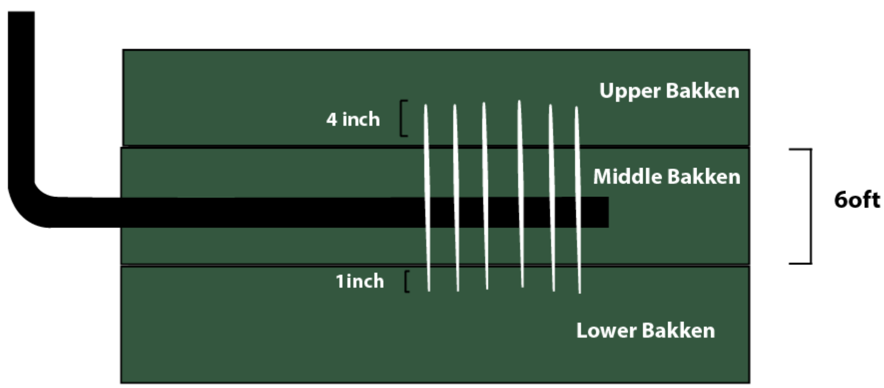


Fig 7: The breakthrough of the fracture into the Upper Bakken and the Lower Bakken.

3. Proppant Slurry

This volume will contain the proppant after the pad is installed. The proppant concentration is chosen to be 4 ppg, in order to not make the fluid too concentrated by proppant and thus would be too viscous and would pose a risk of a screen out. The total pumping time is around 15 minutes and the fluid efficiency is 0.23. The total mass of proppant can be obtained by the following formula:

$$M_p = \bar{c}_p (V_i - V_{pad}) \quad \text{(lbs)}$$

Since Cp = 2.7, Vi = 25,420, and Vpad = 16,020, Mp is calculated to be 25,300 lbs.

In terms of the fluid properties, the Power Law Friction spreadsheet was used. Since the fluid used is the slick water, the parameters are input as n= a, and K = 0.000048. The resulting viscosity is low, so there will be no issue with flowing back to the surface.

Data		
Pump Rate	40	Bbl/min
Pipe ID	3.92	inches
n'	1	
K'	0.000048	
Fluid Density	8.46	ppg
Roughness	0.0006	

Results		
velocity	44.69492	ft/sec
Re	80108.84	
1/sqrt(f)	13.67369	
f	0.005348	
DP	89.30335	psi/1000 ft
equiv vis	2.3	cp

Fig 8: The Fracturing Fluid quality.

4. Flush

This volume will push the remaining proppant down to the bottom of the well. Although the volume pushes the proppant out, it should never over-displace the proppant.

Backup Plans

In order to make sure that the site will always be able to supply enough power for fracturing, it is essential to at least double the available horse power when calculating the required horse power, which is 10,764 hp. Thus, an engineer has to prepare the equipment that will be adequate to supply 10,764 hp. This well will likely not require this much horse power; however, it is always better to be safe and prepared in case anything goes wrong during the process.

Additionally, a good backup plan would be to have an extra blender on site. Since the blender acts as a "mixer" for all out fracturing fluids, it is a very essential equipment for fracturing. If there is only one blender on site and it stops working, the whole fracturing process would need to be paused to wait for the blender. Thus, having extra horse power and extra blenders are the essential backup plan for this well.

Perforations

In order to initiate fractures, an engineer needs to design the perforation task so as to maximize the potential of the fracturing job. The perforation specifications is determined by using the perforation phone application from Schlumberger. The gun diameter needs to be able to fit inside to well, so the gun diameter is chosen to be 3.125 inches. The perforating gun chosen is the PowerFrac3106 RDX, which is commonly used, and was used in the previous tasks. Inputting both the data into the application for fracturing unconventional reservoirs, an engineer would get the following result.

Table 5.1: Perforation Data

Charge	PowerFrac3106 RDX
Shot Per Foot	6 SPF
Gun Diameter	3 1/8 in
Well Bore Diameter	3.92 in
Penetration Length	24.9 in

According to the application, the number of perforations is 6 shot per foot, and perforations should be located 60 degrees apart from one another. This is the best case for perforation task, because have 6 shots of perforation per foot would allow the reservoir fluid to flow into the wellbore from multiple directions. If the number of perforations is 2 rather than 6 spf, there are only 2 entries for the reservoir fluid, and the fewer perforation would result in lower recovery rate and recovery yield ultimately. Additionally, the expected skin before fracturing is the highest when the number of perforations is 6 spf. Thus it is best to shoot the perforations at 6 shots per foot. The calculations to justify shooting 6 shots per foot is shown below.

6 SPF, 60 Degrees

RESULTS	
Plane Flow Effect (s_H) =	*-2.02299*
Vertical Converging Effect (s_V) =	*0.673641*
Wellbore Effect (s_{wb}) =	*0.000673*
Total Perforation Skin Effect (s_p) =	***-1.34868***

4 SPF, 90 Degrees

RESULTS	
Plane Flow Effect (s_H) =	*-1.90981*
Vertical Converging Effect (s_V) =	*0.912655*
Wellbore Effect (s_{wb}) =	*0.003683*
Total Perforation Skin Effect (s_p) =	***-0.99347***

2SPF, 180 Degrees

RESULTS	
Plane Flow Effect (s_H) =	*-1.53687*
Vertical Converging Effect (s_V) =	*1.646748*
Wellbore Effect (s_{wb}) =	*0.042326*
Total Perforation Skin Effect (s_p) =	***0.152207***

After the specifications for the perforation is determined, an engineer would proceed to calculate the skin effect of this perforation task. A negative skin is desirable, because it indicates that the perforation has great effects on the reservoir, and ultimately the production. After utilizing the skin effect calculator, an engineer can calculate the skin as followed:

Inputs

Table 5.2: Perforation Inputs

	Perforation Data	
Well Radius (rw) [Bit diameter = 6”]	0.25	ft
Perforation Radius (r_perf)	0.22	in
Perforation Length (l_perf)	24.9	in
Angle of Perforation Phasing	60	°
Shots Per Foot (SPF)	6	SPF
Horizontal to Vertical Permeability Ration (kH/kV)	10	

Results

Table 5.3: The Skin Results

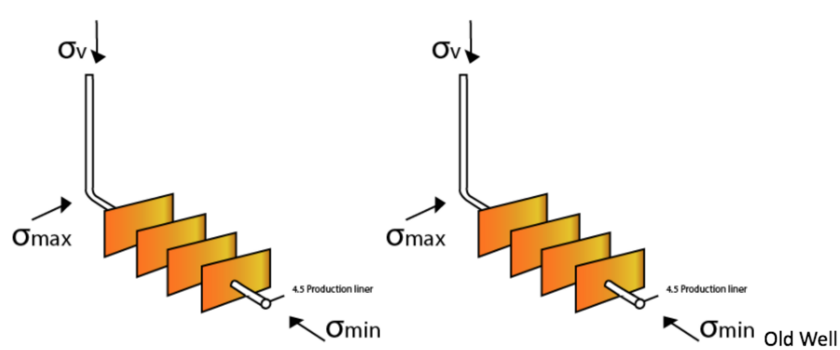
RESULTS	
Plane Flow Effect (s_H) =	*-2.02299*
Vertical Converging Effect (s_V) =	*0.673641*
Wellbore Effect (s_{wb}) =	*0.000673*
Total Perforation Skin Effect (s_p) =	***-1.34868***

According to the skin effect, the skin is negative, which is very desirable for better production.

Frac Hit Defense

Doing fractures in transverse to the axis of the well bore is the best idea to frac this well. It will open substantial volume and increase the flow area. However, since the new well is in a pad with several other wells there is a chance of Frac hit. Frac hit is invading the fractures of other well, which is already producing, having a low pressure region. So, if the fluid is pumped to fracture the new project well, the fluid will travel to low pressure region causing fractures of the new well to invade the fractures of the old well. The proppant from the new project well may plug the fractures of the producing well. Frac hits are seen badly in the industry and cleaning out the long horizontal laterals is really expensive. Thus, to mitigated this frac hit the one way to do it to be careful about the fracture length and don't invade other well's zone. However, this usually doesn't work most of the time because it's hard to determine fracture width with respect to rock strengths. The best way to defend the newly drilled well is to make old producing well to offline (stop the pumps) before we frac the new well. The pressure transducer will be installed on the old. Pressure transducer will show pressure increase if the fracture from the new well hits the old well. The defense is made by renting pump truck filled with some volume of water. Soon the pressure shows up the water is injected in the old well. The water acts as barrier to the frac hit by establishing the higher pressure region. It will cost some money to rent a truck and for water but it is much cheaper than cleaning a well. So, for the new well, the pressure transducer and rented truck will be ready on the old well to defend it from the frac hit. Figure # show a new and old well in the same pad.

Fig 9 : old and new well



Flow Back Mechanisms

Flow back mechanism occurs once all the fracturing materials are in place. At the beginning of this phase, the fracture is still open due to the proppant slurry pumped into the fracture. Prior to dealing with the flow back mechanism, an engineer may operate mini fracs in order to determine the approximate closure time. Also, he could determine the gel break time of the cross linked gel, which is the selected completion fluids.

The most important relationship between the fracture closure time and the gel break time is that the gel should not break before the fracture closes. If the gel breaks before the fracture closes, the injected proppant will settle to the bottom f the fracture, which would make the top part of the fracture unsupported.

It is a common practice to force close the fracture. This could be done by flowing the fluids strongly just long enough to bring the wellbore pressure below the closure pressure. In other words, the flow period needs to be at high rate but short duration. The ultimate goal of this process is to prevent or minimize the amount of the proppant from flowing back into the
Wellbore. Once the fracture closes, the proppant is trapped inside, or near the wellbore.

After the fracture is force-closed, an engineer can order the well to be flowed again to retrieve the fracturing fluid. Some components of this fracturing fluid, cross linked gel, can potentially damage the reservoir. Therefore, removing the fracturing fluid is beneficial for the following processes. It is also essential to make sure that the fracturing fluids are removed, otherwise the reservoir fluids would not be able to enter the well. An excellent fracturing fluid recovery is approximated to be 40-50%. The most important thing to prevent from happening is screen out, since it indicates that the slurry is left behind in the fracture. If screen out happens, an engineer might need to run down the coiled tubing and inject wash out fluid in order to retrieve the slurry. As a result, the well can start producing.

One other aspect of flow back is to determine the flow rate. It is desirable to select as high a flow rate as possible. However, an engineer also needs to make sure that the selected flow rate would not too high, or else proppant would get produced out of the fracture. Therefore, a wise selection of flow rate is essential, and to follow the commonly, or average, flow rate used, an engineer might select 50 barrels per minute as the flow rate for this process. In addition to the flow rate, an engineer can also inject gases, such as Nitrogen and Carbon dioxide in order to create Nitrogen kick, decreasing water content and enhancing flow back.

Preventions in Case of Issues

Screen Out

A screen out can occur when the fracture is plugged by the proppant and the slurry can no longer move along the fracture. This could especially happen when the fracture width is not wide enough. Once screen out happens, the pressure will go up drastically and the whole fracturing process needs to be stopped to prevent a blowout. To prevent a screen out, or to solve the screen out issue, the well should be flowed back as soon as possible in order to get the plugging proppant out of the well. Then, an engineer may attempt to fracture the formation again.

In the real situation, there are some cases the flow back does not work. An engineer would use coil tubing to reperforate the well. Once the well is clear from screen out, an engineer can continue the fracturing job.

Toe Sleeves Fail to Open

Toe sleeves are open pieces of the well bore that opens up portal to the annulus and allow fluids to flow back up, which allows an engineer to pump the perforating guns through the horizontal section. If the toe sleeve is closed, the fluid is pumped into the closed well and pressure will skyrocket. If the toe sleeves fail to open even after pressure gets up drastically, it is essential that an engineer find a way to let fluid flow into the formation without having to rely on the toe sleeve to open.

The best option would be to push the perforation gun down with coil tubing and then perforate the formation. This would help solve all the problems because it allows fluid to get into the formation. In addition, an engineer can use the isolation tool down the wellhead in order to allow high pressure fluid into the well even though the yield might not be enough. He should also make sure that the valves are strong enough to withstand high pressures.

Fracturing Equipment

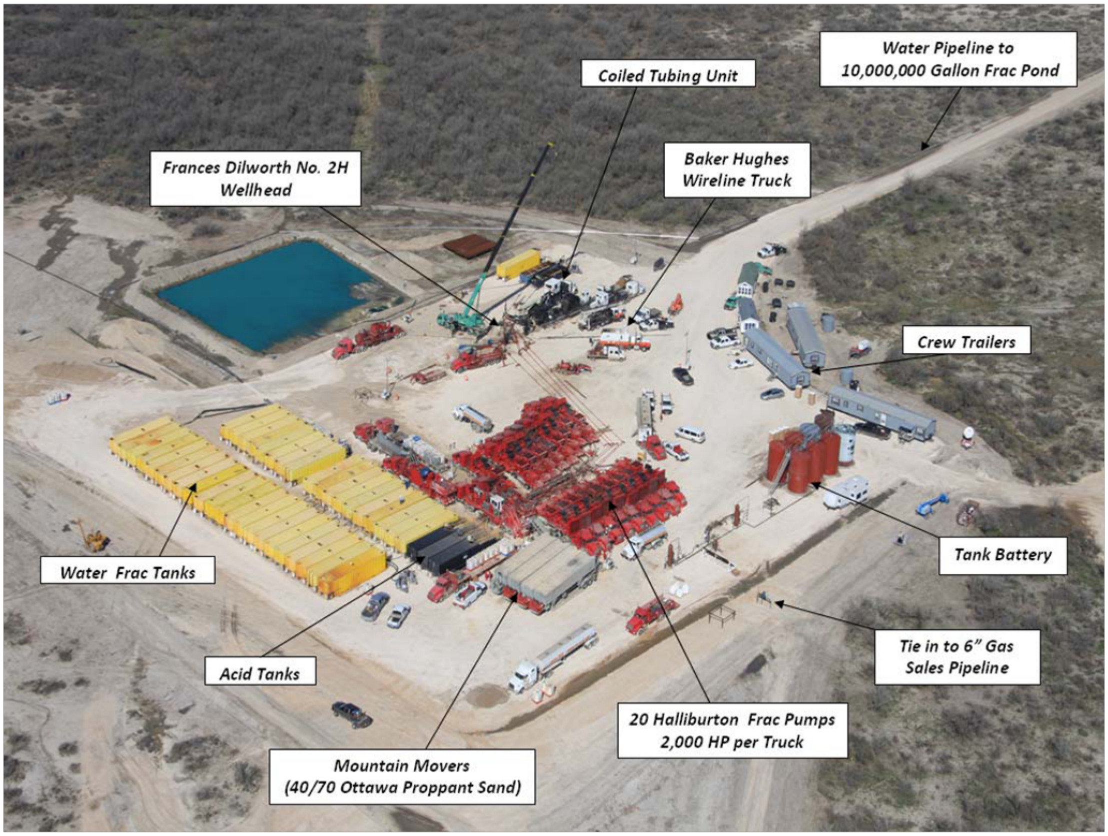


Fig 10: Fracturing Equipment (Bommer, 2018).

The fracturing equipment design for this project is going to be quite an approximate, since there are still a lot of unknown in terms of parameters for surface conditions. However, from the available data, an engineer can probably decide on how many pump trucks he is going to use for the well. The pump truck used will be the Halliburton Frac Pump Trucks; each supplying 2,000 HP. Since the required horse power from the fracturing design is around 4,200 hp, it is essential to have at least 8,400 hp in total to stanby for supplying power to the fracturing job. Thus, it is desirable to have at least 5 Halliburton Frac Pump Trucks on site. Also, the site needs to have a "Mountain Movers" in order to carry the 40/60 Northern sand and supply to the job.

In addition, acid tanks and water frac tanks are required for the fracturing job of this well, since they will supply acid and water to the well. The site should also have a frac water pond in order to supply water, and this pond would have a pipeline connected to water source miles away so that there is no need to transport water.

The blender is also a vital part of this fracturing job, since it serves to mix all the components together. Usually one blender is enough for the process. However, it is always safe to have an extra blender on site to prepare for the worst case when the operating blender does not work.

The coiled tubing unit might be optional for the project until there is any issue, but it will be helpful to have one prepared on site in order not to slow down the process when there is any failure inside the wellbore. This applies to the wireline trucks as well. All the other equipment are going to be designed as the conventional fracturing design for all the wells. For example, there needs to be a trailer for crews, and there needs to be a tank battery to supply power in general.

Flow rates (oil/gas/water) and Decision for Stages

Stages and Clusters

The most important part of the frac job is to select right number of stages. The stages are really important part as production of liquid mostly depends on it. The stages and data that is picked is giving in the table below.

Table 10: Stages and Clusters Picked

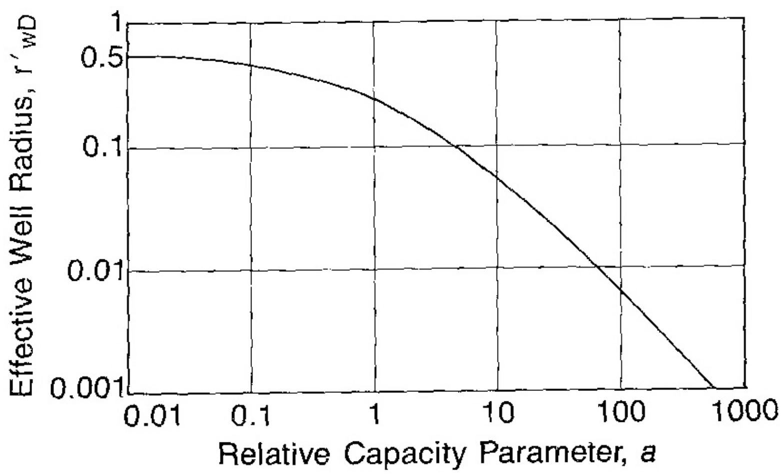
Length	9205
#Stages	30
Spacing	306.8333333
Size	5
Cluster Per Stg	5
SPF	6

The number of stages for this fracturing job is very important for this project. One of the good reference as to how many stages to choose is the given previous wells data. The average spacing for the spacing of the offset wells is 390 feet, which results in around 24 stages in totals. However, according to the SPE-189868-MS Journal, the typical number of stages is around 40 stages. Thus, in order not to be too optimistic or pessimistic, it is desirable to pick the number of stages that is in between the two data. Thus, 30 stages are decided as the number of stages for this well.

Then, the number of clusters per stage was decided. There is a very limited data in terms of how many clusters per stage there should be. Thus, it is desirable to pick the average of the offset wells, which is about 5 clusters per stage. Thus, 5 clusters per stage is decided for this well

Flowrates:

Before Designing further parts of the production system, It's important to calculate the flowrates of the producing fluids. The first part is to estimate and average flow rate ($Qstim$) for oil from the offset wells surrounding the well that is intended to produce. The engineering approach to this is to use Prats Model to calculate flow rates. The skin is calculated first and then the fold of increase from offset wells is calculated with average $Qstim$. The following graph shows the relationship between relative capacity and dimensionless effective well bore radius.



$$a = \frac{kx_f}{2k_f w}$$

$$r'_{wD} = \frac{r'_w}{x_f} = \frac{r_w e^{\;s}}{x_f}$$

$$\frac{Q\,stim}{Q\,orig} = \frac{J\,stim}{J\,orig} = \frac{\ln\left(\frac{r_e}{r_w}\right)}{\ln\left(\frac{r_e}{r_w}\right) + s}$$

$$Qorig = Qstim/FI$$

$Qstim(oilflow\ rate) = FI * (No.stages) * Qorig$------Eq (a)

Due to low permeability, the relativity α is extremely small. The following tables gives the inputs that were used to plug in the equations.

DATA		
avg qsim	398	STB/day
avg stages	24.28	
avg qstim/stage	16.39	STB/day/stage
xf	391	
rw	0.2500	
rw'	0.5	
s	-6.6619	
FI	10.6110248	
qorig	1.544745355	STB/Day/Stage

The fold of increase which is obtained from the frac data and stages that are picked, are used to calculated the oil flow rate $Qstim(oilflow\ rate)$ using Eq (a).

Our well		
stages	30	
Fold of Increase	16.16	
Expected oil rate	748.9	STB/day

Once the oil rate is obtained, it's time to calculate the gas rate. The gas oil ratio

(GOR) is need to calculate the gas flow rate. By adjusting the oil properties excel with reservoir conditions and making the water/oil ratio (WOR) zero, the GOR at the bubble point pressure of the reservoir is achieved.

INPUT DATA		
RESET	Fluid Data	
Oil Gravity	30	API
Gas Gravity	0.83701	
Water Gravity	1.07	
Gas/Liquid Ratio	900	Scf/STB
Water/Oil Ratio	0	bbl/bbl
	Reservoir Conditions	
Pressure	5480	psi
Temperature	250	F
Pressure Increments	100	psi
	Separator Conditions	
Separator Temperature	180	F
Separator Pressure	100	psi

Calculate
Oil Properties

Properties At Bubble Point		
Bubble Point Pressure	4552.17	psi
Liquid Density	45.4269	lbm/ft3
Liquid Viscosity	0.40356	cp
Bo	1.4292	Bbl/STB
Rs	900	Scf/bbl

$$Now\ the\ gas\ rate\ Is\ =\ GOR * Oil\ Flow\ Rate = 900 Scf/STB * 748.9\ STB/day$$

$$Expected\ Gas\ Rate\ = 748.9\ Mscf/day$$

For the water flowrate that will enter the disposal pipe is calculated/estimated by averaging Water flow rates of the offset wells and deriving the Water/oil ratio by diving it by average oil rates respectively. The WOR is then multiplied by oil rate which gives the following water flow rate for the well we intend to produce.

$$Water\ Rate\ = WOR * Oil\ Flow\ Rate = 739.5069\ STB/day$$

Fracturing Cost Estimation

The cost is estimated by inputting the number of stages and the assumption that it would take around 10 days for the fracturing process to be completed. The inputs and results are as followed.

Table 11: Perforation Inputs

GENERAL INFORMATION	
EST. # OF DAYS	10
EST. # OF SLEEVE DAYS	0
EST. # OF PLUG & PERF DAYS	10
# OF STAGES	30
# OF SLEEVE STAGES	0
# OF PLUG & PERF STAGES	30
EST. AVG STP	0
EST. AVG RATE	0
EST. STAGE PUMP TIME - HRS	0
FRAC FLEET MILEAGE	0
STANDBY HORSEPOWER	8,500
STANDBY TIME	0
WATER START TEMP	0
WATER END TEMP	0

RENTAL DETAIL	$/DAY
HOUSING	$800.00
COMMUNICATION	$0.00
FRAC TANKS	$80.00
ACID TANKS	$245.00
LIGHTING	$225.00
MANLIFT	$220.00
FORKLIFT	$125.00
FRAC TREE	$850.00
HEATERS	$0.00
PORTA POTTIES	$125.00
TOTAL DAILY RENTAL COSTS	$2,670.00

FRAC SERVICE CHARGES	
SPREAD COST - $/DAY	$0.00
SPREAD COST SLEEVES - $/STAGE	$0.00
SPREAD COST P & P - $/STAGE	$30,000.00
FRAC MOB CHARGE - $/MILE	$0.00

FRAC STANDBY - $/HR	$4,500.00
SPREAD RIG UP - $/WELL	$0.00
IRON SURCHARGE - $/STAGE	$0.00
PROP HAULING - $/TNM	$0.45
PROP MOB/TRANS - $/LB	$0.00
CONC CHARGE - $/GAL	$0.00
SPREAD FUEL - $/GAL	$0.00

NON-FRAC SERVICE CHARGES	
WIRELINE - $/DAY	$6,000.00
FRAC PLUGS - $/EACH	$1,000.00
PRESSURE CONTROL - $/DAY	$2,000.00
CRANE - $/DAY	$5,500.00
PUMP DOWN - $/DAY	$15,000.00
TOOL HAND - $/DAY	$0.00
FLOW BACK - $/DAY	$1,100.00
WATER TRANSFER - $/DAY	$2,200.00
BACKSIDE PUMP - $/DAY	$2,400.00
CATERING - $/DAY	$1,600.00
FRAC SLEEVES - $/EACH	$0.00
LINER CEMENTING	$0.00
SWELL PACKERS - $/EACH	$0.00
NON-FRAC FUEL - $/GAL	$0.00

FLUIDS				
WATER VOLUMES			**ESTIMATED FLUID COSTS**	
CLEAN VOLUME - BBLS/STAGE	13,500		WATER - $/BBL	$0.50
PUMPDOWN WATER - BBLS/STAGE	200		ACID - $/GAL	$1.15
TOTAL WATER - BBLS/STAGE	13,700		SLICK WATER - $/BBL	$0.09
TOTAL WATER - BBLS/WELL	411,000		LINEAR GEL - $/BBL	$0.00
			XLINK GEL - $/BBL	$0.00
FRAC FLUID VOLUMES				
SLICKWATER VOL - BBLS/STAGE	605			
LINEAR FLUID VOL - BBLS/STAGE	0			
XLINKED FLUID VOL - BBLS/JSTAGE	0			
ACID - GAL/STAGE	1,000			

PROPPANT				
PROPPANT MASS			ESTIMATED PROPPANT COSTS	
100 MESH - LBS/STAGE	15,000		100M - $/LB	$0.07
40/70 WHITE - LBS/STAGE	23,066		40/70 WHITE - $/LB	$0.08
30/50 WHITE - LBS/STAGE	0		30/50 WHITE - $/LB	$0.08
20/40 WHITE - LBS/STAGE	0		20/40 WHITE - $/LB	$0.08
PREMIUM PROP - LBS/STAGE	0		PREMIUM PROP - $/LB	$0.25
TOTAL PROP - LBS/STAGE	38,066			
TOTAL PROP - LBS/JOB	1,141,980			

Note: The proppant used is the 40/60 Northern Sand, and an additional amount of the 100 mesh sand is added to keep the tip of the fracture open.

WELL COSTS	
FRAC COSTS	TOTALS
SPREAD COST - DAILY	$0
SPREAD COST - STAGE	$900,000
FRAC MOB CHARGE	$0
FRAC STANDBY	$0
SPREAD RIG UP	$0
IRON SURCHARGE	$0
PROP HAULING	$0
PROP MOB/TRANS	$0
CONC CHARGE	
SPREAD FUEL	$400,000
FRAC WATER	$205,500
SLICKWATER	$1,705.20
LINEAR GEL	0
CROSSED-LINKED GEL	0
ACID	$34,500
WHITE PROPPANT	$86,858
PREMIUM PROPPANT	$0
FRAC TOTAL	$1,628,564

NON-FRAC	TOTALS
RENTAL EQUIPMENT	$26,700
WIRELINE	$60,000
FRAC PLUGS	$30,000
PRESSURE CONTROL	$20,000

CRANE	$55,000
PUMPDOWN	$150,000
TOOL HAND	$0
FLOWBACK	$11,000
WATER TRANSFER	$22,000
BACKSIDE PUMP	$24,000
CATERING	$16,000
FRAC SLEEVES	$0
LINER CEMENTING	$0
SWELL PACKERS	$0
NON-FRAC FUEL	$0
NON-FRAC TOTAL	**$414,700**
FRAC ESTIMATE	**$2,043,264**

According to the Frac Cost Estimator, the rough estimate of the fracturing cost would be $2,043,264, which is relatively low. The revenue the well will bring will be substantially higher than $2 million and thus the fracturing process is worth completing.

Flow Assurance and Issues with Fluids

Water Coning (None)

Usually water coning is a problem that engineers are afraid of, since once the well makes contact with water, there will be a great difficulty in terms of cancelling that contact. Since this Bakken Well is drilling into a nano-darcy reservoir, there will not be any issues with water coning. The small permeability will prevent water to reach and make any contact with the well.

Gas Hydrates, Paraffin and Asphaltene (None)

Hydrates, Paraffin, and Asphaltene are also common issues that engineers face during production. When the wellbore temperature goes down to the “cloud point” temperature, paraffin (wax), and asphaltene (tar) will form and block the flow of the well. High cloud points will result in easier formation of paraffin and asphaltene. Thus, it is desirable to have a low cloud point temperature oil in order to prevent asphaltene and paraffin. In addition, when temperature drops to some value, vapor in the gas phase will precipitate and will cause the similar blockage issue. This can be prevented by lowering the freezing point, possibly by adding a solvent into the fluid. The common way is to inject methyl alcohol.

In this project, gas hydrates are not expected because there is no presence of gas in the reservoir initially. Paraffins and Asphaltenes are also not expected. However, if they do form, a good solution would be to inject foam pig in order to sweep all the solid particles by scraping the pipe walls.

Note: For more details in gas hydrates, refer to the facilities section of this report

Corrosion

Corrosion is the loss of metal due to chemical reactions. The corrosion rate will vary with time depending on the particular conditions of the oil field, such as the amount of water produced, secondary recovery operations and pressure variations.

Fig 11: Picture of a well corrosion

Corrosion Treatment:

The most common method to prevent corrosion is to use chemical inhibitors, which coat the metal and prevents its contact to electrolyte. The choice of inhibitors is conducted in the lab or in the well. If you have a water sample or a replicate, it can be test in the lab for metal loss. It takes some time to get it test since metal need time to corrode before the different inhibitors are tried to see if they slowdown or not. This is experimental technique but some people do this in the well. They alter the concentration of corrosion chemical depending on the corrosion rate. In addition, experience in field may yield a good solution indeed.

The most popular way to get the inhibitor in the well is by injecting in the annulus. The other possibilities is if the well has packers, the flow is coming up in tubing only perhaps to protect the casing and defend the inside of the tube. The coil tubing (injection string) 3-1/4 stainless steel and chemical can be entered at the bottom of the well. However, it is an expensive process.

For our well, there is a packer installed to place 4.5 inch in a 7-inch casing. However, before starting artificial lift, the 4.5-inch string is removed and then the inhibitor can be injected in the annulus. Therefore, it is decided that the inhibitor will be injected in the annulus of the well to prevent corrosion. There are other corrosion protection methods such as cathode protection and coating, but for this project, using inhibitor is a great choice.

Corrosion Monitoring:

To monitor corrosion when the well starts producing, the sample water is send to the water lab every month for testing. The dissolved iron is counted in the sample and if the iron count increases on monthly bases, then it will be sure that, it is from the corrosion. However, in a well with no H2S, the iron count is meaningful but in a well with H2S, it is misleading as the iron is precipitated in another part of the system and do not show up.

The best way to monitor corrosion for the production system is using the corrosion coupon at the surface or close to wellhead. The fluids are exiting the well and it could be tapped by drilling a hole off by screw into the pipe with plastic, which has piece of metals bolted on it. The metals are expose to the flow of the well fluids flowing by it. It is unscrewed time to time and weighed to see how much metal is lost. This process will help to know the rate of metal thickness loss or the corrosion rate.

$$R = \frac{m}{A \quad t}$$

$$\begin{aligned} R &= \text{ corrosion rate } \left(\text{thickness loss / time}\right) \\ m &= \text{ loss of coupon mass} \\ t &= \text{ test duration time} \\ &= \text{ coupon material density} \\ A &= \text{ coupon surface area exposed to corrosive fluid} \end{aligned}$$

There could be another possibility of corrosion that predominantly make pits. The issue is also that how deep are the pits, which is important to know because it shows the thickness of the pipe changing. The depth of the pits can be measured and the deepest will be the one that we are more concerned about. So the pitting rate (thickness loss/ time) can be calculated.

$$PR = d/\nabla t$$

The general guidelines for the corrosion rates are in the following table:

Table 13: Corrosion and Pitting Rate

Corrosion Severity	Corrosion Rate (mil/yr)	Pitting Rate (mil/yr)
Low	< 1.0	< 5.0
Moderate	1.0 - 4.9	5.0 - 7.9
Severe	5.0 - 10.0	8.0 - 15.0
Very Severe	> 10.0	> 15.0

in/yr = mil/yr/1000

There are several other methods to monitor corrosion such as running caliper and electromagnetic logs to determine metal loss. However, these methods are expensive and it is clearly better to use corrosion coupon method to determine the corrosion rate for our production system.

Well Head Design

Well Head (Picked rating for this project 10,000/20,000 psi)

To begin discussing the well head of this project, it is essential to consider the importance of the high pressure connector. The high pressure connector allows the casing strings to attach on and thus is one of the most critical design of the well. The high pressure connector was connected to the well head as a part of it.

The well head used in the project needs to be robust and tough, since it will confine pressure and control the flow, which requires it to tolerate the flow and the shut in conditions of the well. As discussed earlier, the high pressure connector, a part of the well head, will serve as the place to carry all the casing strings. The well head also needs to be able to withstand corrosion, since it is always exposed to flow and the surrounding environment. Thus, it is very common to coat the inside of the wellhead with metal. Usually, stainless steel is a very anti-corrosion coat that will allow the wellhead to have a long life span.

In terms of force resistivity, the wellhead may also be "called upon to survive impact." There is a possibility in the field condition that tractors will hit the wellhead and snap the wellhead off. In this scenario, there is likely going to be a blowout. Thus, the wellhead needs to be able to resist collision.

To discuss what type of wellhead to use, an engineer needs to consider that wellheads are rated by two main criteria: size and pressure. The pressure criteria is separated into the working pressure and the test pressure. The working pressure is defined by the normal operating pressure that the wellhead will be exposed to and the test pressure is the exceeding pressure that is tested on the wellhead to make sure that the wellhead is strong enough. The usual working/ test pressure ratings are 3000/6000, 5000/10,000, 10,000/20,000, and 15,000/17,000 psi. In this project, the surface treating pressure for the pad is less than 5,000 psi (refer to the result from the Frac Data & Results Spreadsheet), and the red line pressure is around 9,600 psi. Thus, the appropriate rating for the wellhead of this well would be 10,000/20,000 psi.

The connection of the wellhead is also worth discussing, all the pieces are "flanged" together in order to ensure tight seals. Seal happens when the ring of the flange is put in compression, creating a very robust connection. In this case, the well is able to flow by itself, since it is in a relatively high pressure environment, considering that the reservoir pressure is almost two times the surface pressure. Therefore, using a flanged wellhead is desirable.

Steps for installing wellhead

First, the casing or Braden head is installed. The head is attached to the surface casing through threading or welding. It also has a bowl inside to be a foundation to the next piece of the wellhead.

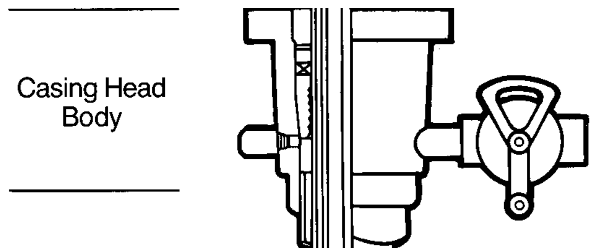


Fig 12: Casing Head (Bommer, 2018)

Then, the intermediate casing is attached to the Braden head. Afterwards, the Casing head spool, is installed on top of the Casing head. It also has a bowl to be a foundation for the next head.

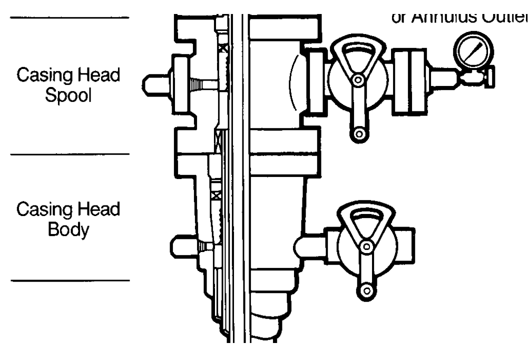


Fig 12.1: Casing Head Spool (Bommer, 2018).

The next step is that the production casing is attached to the casing head spool with slips and seals. Afterwards, the tubing head is attached on top in order to prepare for the landing of the tubing. It can also access the inside of the production casing. Similar to the rest, it has a bowl to accept the next head.

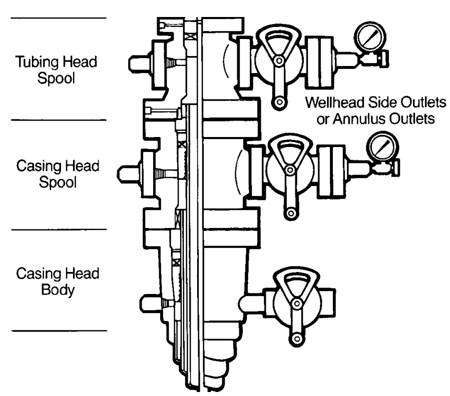


Fig 12.2: Tubing Head (Bommer, 2018).

Next, the production tubing is attached to the tubing head, and the Christmas Tree, or the Upper Tree Assembly is attached and sealed. Now, any flow through the tubing is controlled through valves and choke. This Christmas Tree still allows access to the tubing.

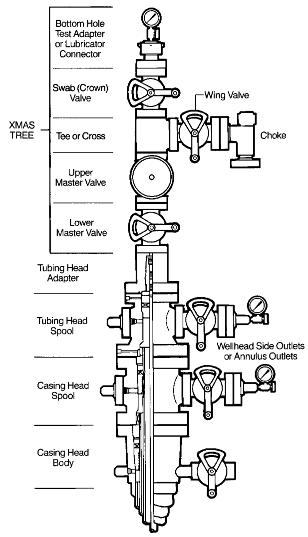


Fig 12.3: Well Head Assembly (Bommer, 2018).

After the wellhead is installed, it is essential to test the assembly at the working pressure again in order to confirm that the wellhead works in the condition. Also, the wellhead needs to be lubricated at least once a year in order to maintain its quality. Maximum tolerable pressure must also be attached to the wellhead in order to inform operators on what the dangerous pressure would be.

Valves

Two master valves are required for safety of this well. The most probable valve that will be used in this project is the Gate valves, since it is very robust. The valves need to be either completely opened or completely closed. Otherwise, in the case of well throttling, the flow velocity would be excessively high, which leads to the corrosion of the well head.

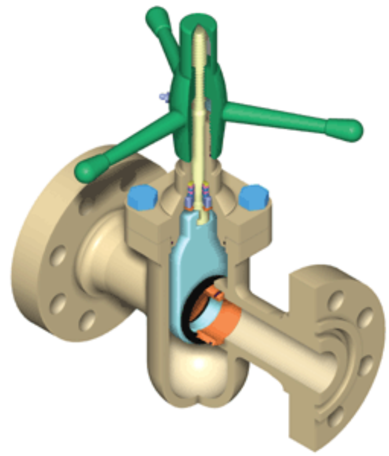


Fig 13 : Gate Valves (Bommer, 2018).

Choke

The choke is one of the most essential elements of this design. This is because the choke help controls the flow be manipulating the pressure from the wellhead. The main principle behind the choke is simply the conservation of energy, where the kinetic energy of the fluid changes as it passes through the choke.

The choke itself is just a short piece of pipe with small diameter. One helpful design for this project is to use the adjustable choke. This would allow the choke to be drilled deeper or pulled back out. When the spear of the choke is inside the tube, the choke is closed and thus allow no flow, and vice versa.

The choke diameter is based on the design of an engineer that would be justified when the well is actually producing. If an engineer wants a fast flow rate, he might use a large diameter choke in order to reduce Pwf, and thus increase the draw down. After the choke is chosen and once the well is producing, an engineer can find the actual flow rate by the liquid flow through choke, gas flow through choke, and two phase flow through choke equations. The general inputs for finding the actual flow rate would be the choke diameter, the draw down pressure and the temperature.

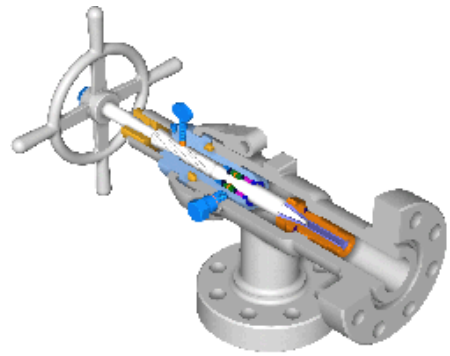


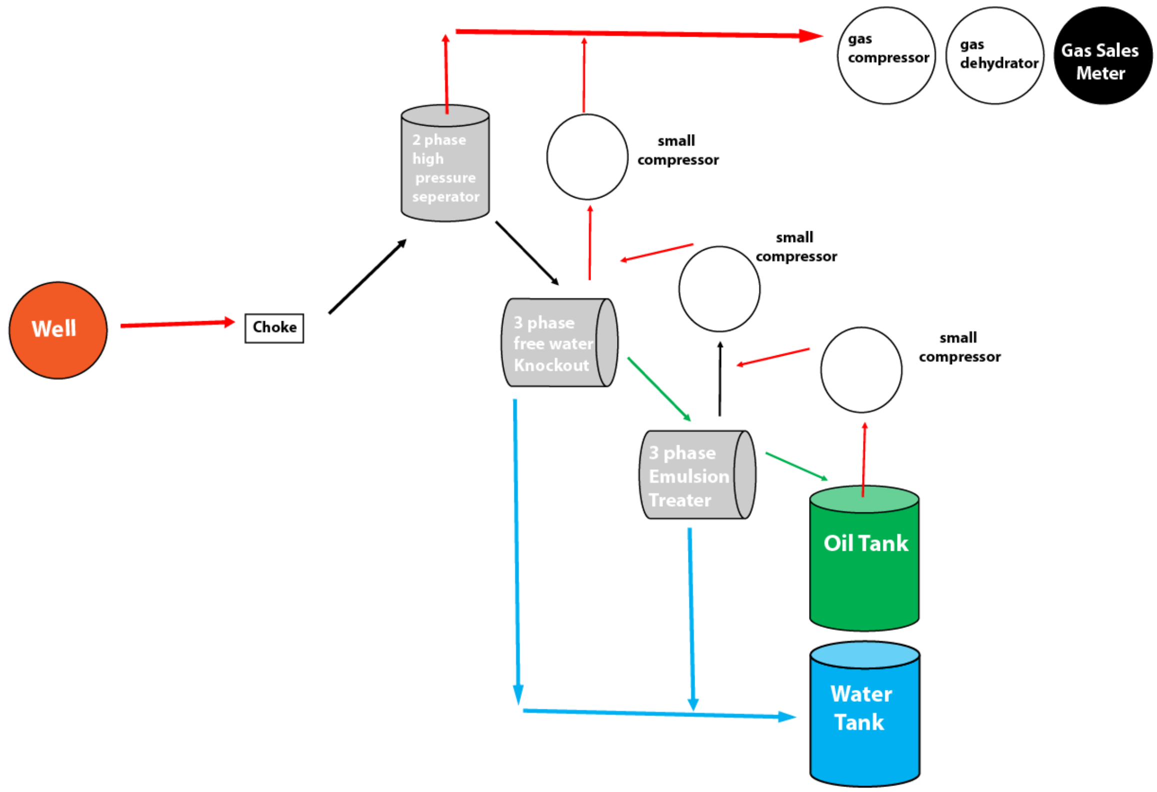
Fig 14: Adjustable Choke Chosen for this Project (Bommer, 2018).

Facilities

The Facilities is one of the biggest part of the production system and its needs to be carefully designed. The oil obtained from well should be 99% oil. If it isn't, for example, if it has 1% sediment or water, then people won't buy it. The volume of water or sediment will be deducted. If there is facility and it is working correctly it can be hoped that more than 99% oil can be obtained. However, there is always a chance of contamination and contractors won't buy it if the value of contamination is more than what is minimum specified in the contract. Similarly, for gas, It is sold on the Btu bases. The gas that come out always comes out with some water vapor from the well. The sales contract doesn't want much water. The gas sales contract will tell us the value of minimum water content in the contract, which is usually something around 7 pounds of water per Mscf (Bommer). The water tank is mostly waste. When it is full, it is shipped in water disposal facility through the water flow pipe that is designed in the pipeline section and the water is injected underground.

In a general facility the fluid obtained is separated into three different containers and flows from the container with the highest pressure to the one with the lowest. The second-high pressure separator forces the fluid out and into other separators and the liquid is now separated from the gas. Gravity causes the liquid to coalesce on the bottom while the gas is forced out. The liquid then passes into the 3 phase water knock out separator, where the liquid is separated into oil and water. Then the separated oil is transferred into the emulsion treater where the emulsion (a fine dispersion of minute droplets of one liquid in another in which it is not soluble) of water and oil is treated. At that point, the fluid which is 99% oil enters the oil tank. The gas released from the third phase is separated out at every step by a drop in pressure.

Fig 15: General Facility Outline



For separator, it can have been chosen to maximize gas recovery or the oil recovery as these fluids flow through separator. There are four separators, the 2 phase separator, 3 phase water knock out, emulsion treater and the oil tank. The oil is valuable and has about 6MMBTU in it, generically, on the other hand the generic gas has 1MMBTU/Mscf. Thus, on BTU bases the oil is more valuable.

The separation ratio is how much pressure at the separator is reduced at each separator. The following equation shows the relation.

$$R = \left(\frac{Pfirst}{Plast}\right)^{1/(n-1)}$$

where n is number of separator, $Pfirst$ is the first separator and $plast$ is the stock tank. The first separator has a pressure of 1014.7 and the last separator has 14.7 Pisa. Using the equation following pressures are received for each separator.

Table 17: Separator Pressures

Separator no	Pressure
1	1014.7
2	248

3	60
4	14.7

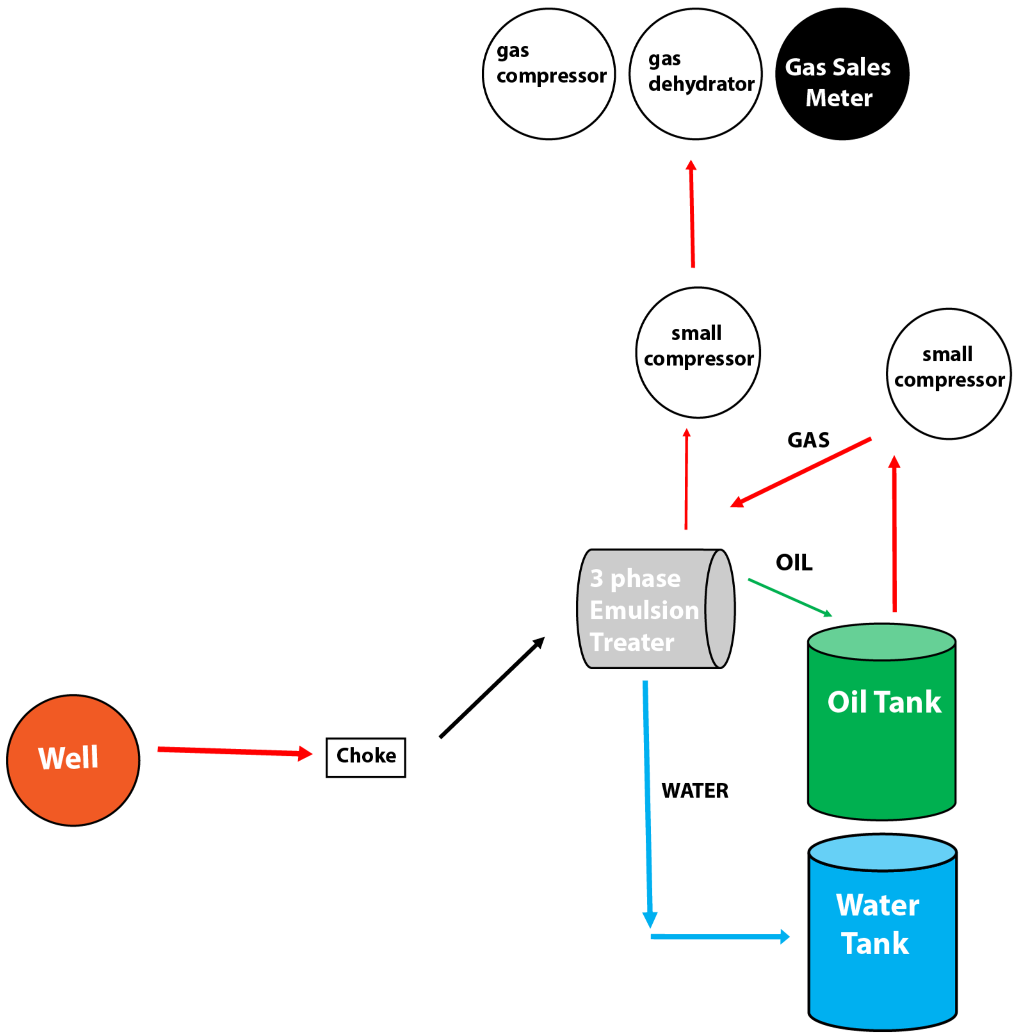
The 1014.7 psia is really high pressure for 2 phase separator. The back pressure regulator senses pressure in the vessel. When the pressure gets above the set point of pressure, the regulator opens and the gas is released. If the back pressure regulator fails anytime and to avoid this there is a safety relief valve. The safety valve opens and releases everything when the pressure reaches the maximum rating. The separator also has drain where the solids are collected.

After separating water from oil in water knock out separator, the oil emulsion is broken down. The breakdown of emulsion is achieved by holding the emulsion longer in the emulsion treater but gravity has not much effect. The addition of heat is the really what works here. The head reduces the oil viscosity and causes water molecules to move faster. The droplets of water collision increase the size of water droplets the sooner the gravity settles it. For the facility design its hoped that heating will work or if heating doesn't work then some expensive methods such as using charge and emulsion breaking chemicals can be used.

The Design of Facility for our Production system

In North Dakota, the predominant issue is separating the oil from the water. Its required that liquid remains warm and doesn't freeze on below zero-degree North Dakota night. The oil and water is doing not sit for long so the water and oil won't get solidify. So, the 2 phase separator is not needed here. The gas can be separated in other vessels. Every time we put new vessel here, its opportunity for things to get cooler. The big enough emulsion treater can handle all free water, emulsion and gas that goes out on the top. Hence, there is no need for water knockout separator. The natural gas is burned in the fire tube to generate heat need to make liquids hot and separate it into water, oil and gas. Even in North Dakota today you cannot burn gas indefinitely. To avoid wasting and burning the compressor is needed. It is needed to pump gas since the emulsion treater operates in low pressure.

Fig 16: Facility design for the well



The specifications for the three phase emulsion treater is picked based on the oil, gas and water flowrates that we calculated in pipeline design. Using the chart in the canvas the following emulsion heater treater fits well for the job that needs to get done. Table 17.1 shows the specifications of emulsion treater that is planned to be used.

Table 17.1: Three phase emulsion treater specifications

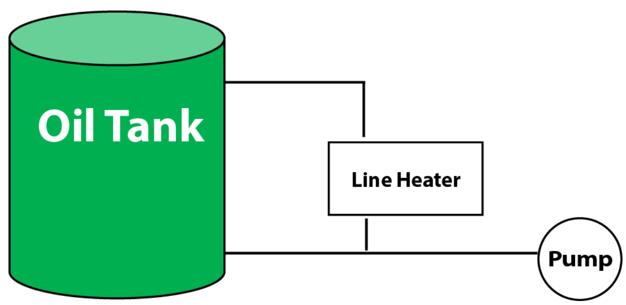
Three Phase Vertical Emulsion Heater Treater	
Operating Pressure (Psi)	50
Vessel Size (D" X L')	96" x 20'
Gas Rate (MMcf/Day)	6
Oil Rate (BOPD)	1200
Water Rate (BWPD)	2500

Heat Capacity (MBTU/hour)	750

The green tank in the fig 16 is used to store oil. The vapor coming out of theses tanks are due to a small pressure drop from emulsion treater to tanks (~60 psi to 14.7 psi). The small flow rates of vapor released from tanks and is compressed by the vapor recovery unit (small compressor) to make it enter into the suction. Also, the emergency flare is installed if the compressor fails. Note, there are two small compressors in the total system since compressor operates at different pressure boosts. Emulsion treater and tanks have different pressure due to which two compressors are required.

Also, in this coldest state of North Dakota, the colder weather causes oil viscosity go high and can be a big problem when it comes to pumping it in pipelines. Line heater are used at some places to avoid the solidification of oil. Line heater is use to cool down the gas, which is cooled in the choke due to the pressure drop. The well produces both oil, gas and water, which has enough heats and it's highly unlikely to produce gas hydrates. Hence, line heater is not needed. However, some cold days the line heater might be needed to make liquid (oil and water) hot enough to make sure it flows in the pipeline. The line heater uses natural gas directly obtained from the well and burns it in its fire tube. It's again the loss of opportunity of selling that gas, but is not expensive than using electricity and other source of fuel. Antifreeze can also be choosing to avoided freezing but it's costly.

Fig 17: Typical Line heater setup



Furthermore, the volume of gas is need to be measure as per contract probably once per month (Bommer). The gas flowing in pipe per day can be calculated. The continuous gas flow rate is commonly measured by use of an orifice meter, which is thin plate choke. The pressure upstream and downstream across the plate and the choke flow equation can be used to finally calculate the gas volume and at the end of the month, this is the gas that is basically sold. The following choke equation is used.

$$q_{sc} = 974.925C\sqrt{\frac{1}{{}_{g}z_1T_1}}p_1d_2^2Y$$

$$\text{where} \quad = \frac{d_2}{d_1} \quad \text{and} \quad Y = \sqrt{\frac{\frac{k}{k \quad 1} \quad 1 \quad \left(\frac{p_2}{p_1}\right)^{(k \quad 1)/k}}{\left(\frac{p_1}{p_2}\right)^{2/k} \quad {}^{4}}}$$

q_{sc} = gas flow rate at standard conditions (MScf/Day)

p_1 = up stream flowing pressure (psia)

T_1 = up stream flowing temperature (deg R = 460 + deg F)

z_1 = gas deviation factor at up stream flowing conditions (dimensionless)

${}_{g}$ = gas specific gravity

p_2 = down stream flowing pressure (psia)

d_1 = up stream (pipe) diameter (in)

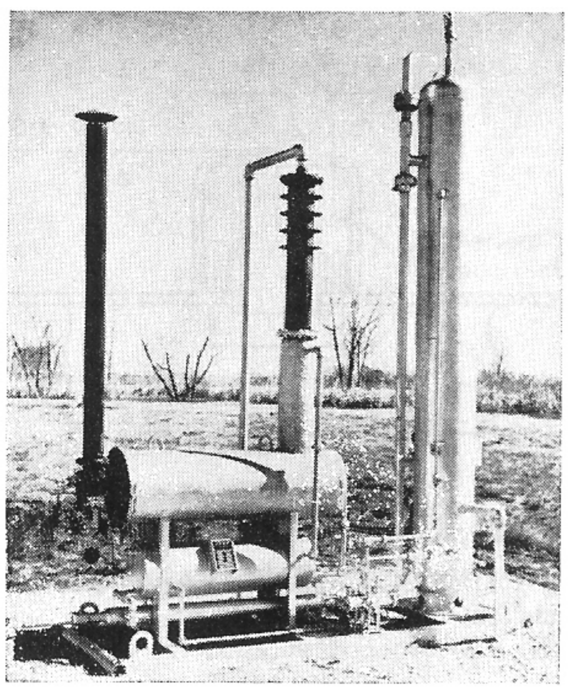
d_2 = down stream (choke) diameter (in)

k = gas isentropic exponent (dimensionless)

C = discharge coefficient to be determined

Finally, the gas dehydration is need to be considered. The sales contract will specify that vapor content should not exceed some limit (mostly 7ppg). The raw gas in entered into the glycol dehydrator. The gas bubbles up the tower where the gas contacts with the liquid having affinity of water. The glycol absorbs enough of water vapor and gas is dehydrated. The glycol is reused by liberating steam, which condenses and its pumped back.

Fig 18: Glycol Dehydrator



The Last part of the facilities is compressor design. The gas needs to be pumped in the pipe at desired pressure and here is the graph that shows 4 different types of compressor. The difference of the compressor is based on the suction pressure (pressure at the entrance of compressor). The gas is mostly coming from heater treater operating at 60 psi and stock tank barrel, which is operating at 14.7 psi. So

62.73 pisa suction compressor is really close to the operating emulsion treater and 14.73 psi suction compressor for the stock tank. Using the exit/discharge pressure out of the compressor into the gas pipe, which is 1014.7 psia the horsepower of the compressor can be calculated using figure 19. The horsepower is set according to the gas flow rate.

Fig 19: Compressor performance

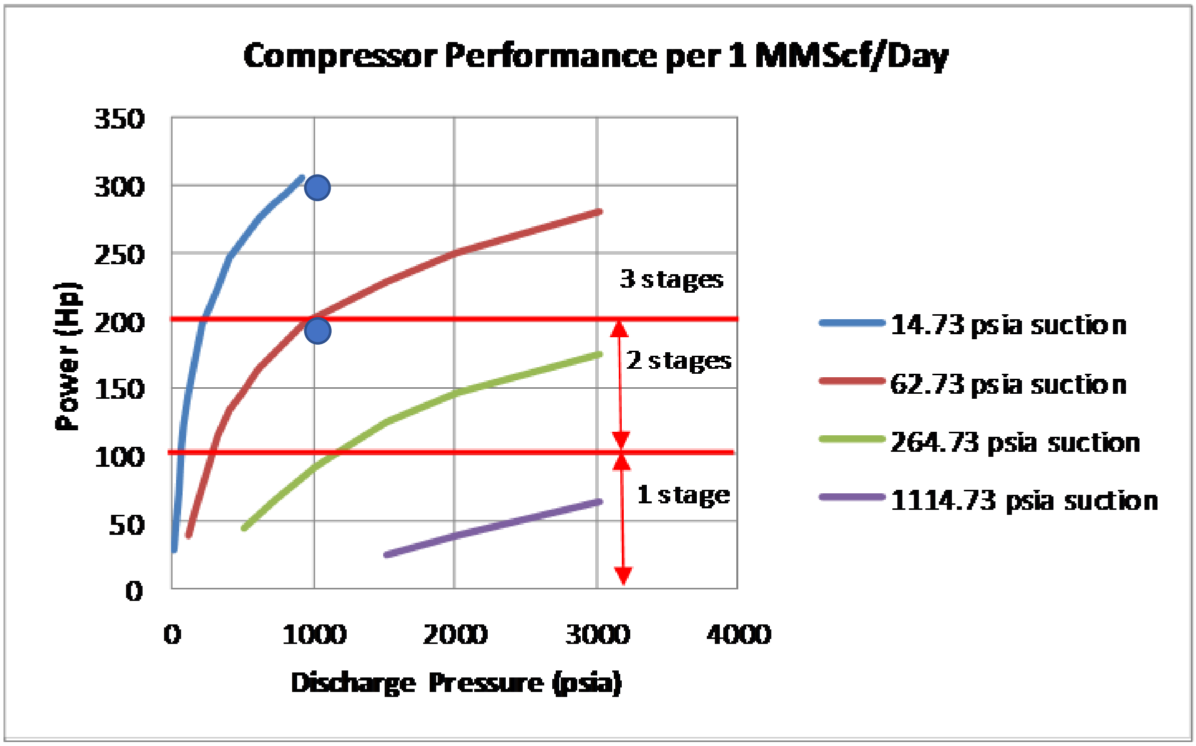


Table 17.2: Compressor power

Separator	Operating pressure	Compressor discharge pressure (pia)	Gas Flow rate (MMScf/day)	Power (HP) needed
Emulsion Treater	60	1014.7	0.647	129.4
Stock Tank	14.7	60	0.647	64.7

The 1 stage of compressor takes the gas at the suction pressure and it can pump it up about the factor of 4 or less (Bommer). The 1 stage can give may be 250 psia discharge pressure. The one stage can't do it all the way to 1014.7 pisa because the gas is hot. So, the gas is passed into radiator and cooled. The cooled gas is then entered into the second stage cylinder and this gives us 1000 pisa pressure. The gas is hot again and is passed into the radiator and passed into the third cylinder (3 stages) to get to the right discharge pressure. So, 3 stage compressor is needed here.

However, we have only one well and we don't need the small compressor on stock tank but to accommodate future wells the small compressor is needed on the tank that has a discharge pressure of 60 psia so the gas coming out is injected into the 62.73 psia suction of compressor attached to emulsion treater.

The final part of the facility design is calculating the horsepower for the pumps that will be need to transport oil. Liquid pumps are sized by the volume of the pump and pressure needed to exit that pump. The hydraulic horse power of the pump can be calculated from the following.

$$HHP = flowrate(q) * Inlet\ pressure\ of\ the\ oil\ pipe$$

$$oil\ flowrate = 748.89 \frac{BBl}{day} \cong double\ for\ worst\ case = 1500\ bbl/day$$

$$Inlet\ Pressure\ of\ Pipe = 50.8\ psi$$

$$= \frac{1\ day\ hr\ 1500\ BBL\ 50.8\ lb\ 5.615\ ft^3 144\ in^2}{day\ 60 \min 24\ hr\ in^2 bbl\ ft^2 33000}$$

$$= 1.296\ lbf/min\ Hp$$

Same pump can be used for pumping water as the flow of water and inlet pressure is about the same. The further break horse power can also be calculated using the following equation.

$$The\ Break\ Horse\ power = \frac{HHP}{Effieciencyfactor(e)}$$

Now, the facility is ready for the produced liquids coming from the well and ready to sell and make money by transporting it through the pipelines. The facilities engineers and employees will take care and make sure it is running well.

Pipeline Design

Calculating Gas Property

The properties of gas are essential for determining the gas pipeline, since it will give the specific gravity of gas, which is a required input for the Incompressible Single Phase spreadsheet. An engineer would fill in the gas components data given from the field. The inputs and results are as followed.

GAS COMPONENTS/ GAS GRAVITY		
RESET	*Fluid Data*	
C1	*59.3*	%
C2	*17.73*	%
C3	*9.42*	%
i-C4	*0.7*	%
n-C4	*2.03*	%
i-C5	*0.27*	%
n-C5	*0.38*	%
n-C6	*0.16*	%
n-C7	*0.11*	%
C8+	*0*	%
CO_2	*0.51*	%
N_2	*7.1*	%
H_2S	*2*	%
H_2O	*0.29*	%
	Reservoir Conditions	
Pressure	*5480*	*psi*
Temperature	*250*	*F*
Pressure Increments	*100*	*psi*

Table 18.1: Inputs for Gas Property.

Critical Properties		
Gravity	0.83701	to air
Ppc	665.735	psi
Tpc	418.678	R

Table 18.2: Gas Property.

<u>Calculating Oil Property</u>

Similar to the gas property, oil property is also an essential element for designing the pipeline. In this case, it is assumed that there is no water phase. In addition, the bubble point of the fluid is assumed to be the atmospheric pressure (14.7 psi), since it is desirable to still have only the oil phase. The inputs for "Reservoir Conditions" are substituted by the surface conditions, and the temperature is assumed to be the worst, which is the outlet temperature of 60 degrees Fahrenheit. The other parameters are input as given, and the GOR value is iterated until the calculated bubble point is close to the atmospheric pressure.

RESET	*Fluid Data*	
Oil Gravity	30	**API**
Gas Gravity	0.83701	
Water Gravity	1.07	
Gas/Liquid Ratio	2.5	**Scf/STB**
Water/Oil Ratio	0	**bbl/bbl**
	Reservoir Conditions	
Pressure	14.7	**psi**
Temperature	60	**F**
Pressure Increments	100	**psi**
	Separator Conditions	
Separator Temperature	180	**F**
Separator Pressure	100	**psi**

Table 18.3: Inputs for Oil Property Calculation.

Properties At Bubble Point		
Bubble Point Pressure	14.5618	**psi**
Liquid Density	54.637	**lbm/ft3**
Liquid Viscosity	181.002	**cp**
Bo	1.00117	**Bbl/STB**
Rs	2.5	**Scf/bbl**

Table 18.4: Oil Properties at bubble point.

Pressure (psi)	*Liquid Density (lbm/ft3)*	*Liquid Viscosity (cp)*	*Bo (Bbl/STB)*	*Rs (Scf/bbl)*
14.7	54.64433	181.0031	1.001036	2.5
14.7	54.64433	181.0031	1.001036	2.5

Table 18.4: Oil Properties.

<u>Oil Pipeline Design</u> (Flow rate = 748.89 STB/day)

After the calculated flow rate of around 750 STB/day is acquired and the oil properties are determined, the next step is to design the oil pipeline. The oil viscosity and density are inputted from the oil properties and the variable is the pipe diameter. The other parameters are inputted as given, except the pressure drop that is going to be the result of the calculation. It is important to note that the value for oil flow rate plugged into the calculation is actually 1,500 STB/day, which is doubled the value of the calculated flow rate. This is in order to assume for the worst case scenario, in order to make sure that the designed pipeline will not have any problem in the future.

RESET	*Fluid Data*	
Density	54.7	**lbm/ft3**
Viscosity	181	**cp**
	Wellbore Data	
Diameter	7	**in**
Length	26400	**ft**
Angle	0	**deg**
Roughness	0.0006	
	Flow Data	
Pressure Drop	460	**psi**
Flowrate	1500	**Bbl/D**

Table 18.5: Inputs for Calculating Pressure Drop Over the Pipe.

After the pressure drop is calculated for each guessed pipe inner diameter, an engineer can calculate for the inlet pressure into the pipe by adding the pressure drop to the given outlet pressure, which is 39.7 psia. Thus, the inlet pressures associated to the pipe inner diameters are calculated as followed.

Diameter	Inlet Pressure
4	110.9
4.5	81.2
5	65.3
5.5	56.3
6	50.8
6.5	47.4
7	45.2

Table 18.6: Inlet Pressure of Each Pipe diameter.

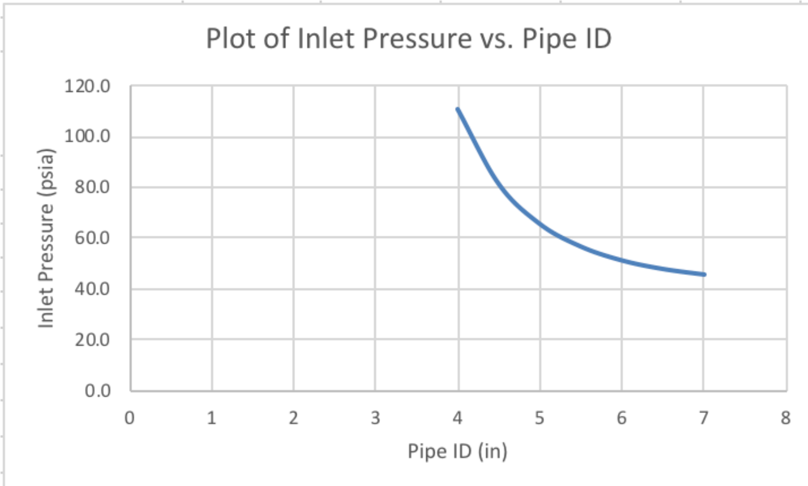


Fig 20: Plot of Inlet Pressure vs. Pipe ID.

Seeing from the plot shown above, the inlet pressure is starting to plateau as the pipe ID gets bigger. Once this happens, the pipe ID is reaching the point of diminishing return and there is no use picking bigger pipes any more. According to the plot, an engineer might pick 6 inches as the oil pipe. Picking bigger ID pipes will be a lot costlier and will not be economically reasonable.

Then, an engineer would start designing the oil pipeline. One important design in this case is the maximum allowed operating pressure (MAOP). This MAOP is the worst case pressure that would ever happen to the pipeline. It is determined by using the inlet pressure. Since the inlet pressure is only 50.8 psi, an engineer might double that value to get the MAOP, since the pipe grade would not change that substantially for low pressure. The next step is to pick an initial guess for the pipe grade from the inner diameter, which is 6 inches. An engineer might pick 6.625 as the OD for this pipi, in order to sustain reasonable cost, while robust pipes.

As an engineer pick the first guess for the pipe, she would calculate the S*t (yield strength * thickness) of the chosen pipe. This is called the actual S*t, which is then compared to the calculated S*t, which is obtained from the following formula,

$$1.5(MAOP) = \frac{2St}{D} FET$$

When D is the outer diameter of the pipe; F, E, and T are correction factors for the environment that the pipe is going to be in. In order to assume the worst case, F is assumed to be 0.4; E is assumed to be 0.8; and T is assumed to be 1.0.

If the calculated S*t is lower than the Actual S*t for the pipe, the pipe pass the first criteria of the yield strength. The next step is to determine the real pipe ID. Since the chosen pipe for this case is 6.625 inches OD, STD, the actual pipe ID would be 6.065 inches. After then, an engineer would proceed to calculate the maximum internal pressure determined by the manufacturer. This is the maximum pressure that the pipe can tolerate, and it is calculated by the Barlow's equation as follows,

$$p_i = \frac{2(0.875)St}{D}$$

The mill test pressure is then calculated from Pi by the following formula,

$$p_{milltest} \cong 0.8 p_i$$

The next important step is to calculate the design burst pressure. This is done by the following formula,

$$p_d = \frac{2St}{D} FET$$

Then, the test pressure for determining that the line is not leaking at the time it is constructed is calculated from the larger value between (1.25*P_d) and (1.5*MAOP). This pressure is very important for checking the validity of the pipe.

The last step is to check whether the pipe qualifies as a valid pipe according to the ASME's CODE. This criteria varies per state. However, the common one used is the ASME B31.8. The CODE criteria is then specified as the following:

- The calculated design burst pressure and the test pressure shall not exceed 85% of the mill test pressure for ERW or seamless tubes
- Except for butt welded, where the calculated design burst pressure shall not exceed 60% of the mill test pressure.

In this case, the butt weld is out of consideration, since it is expensive. Thus, the CODE tested will be for the fillet weld pipe due to its availability in the market and its low price. The design pressure and the test pressure are then compared to 85% of the mill test pressure, and the pipe validity is determined. The results are shown in the following tables.

Table 18.7: Oil Sale Pipe Line Design

Design: 6.625" OD, 18.99 ppf, STD, Fillet Weld.

Flow Rate (bbl/day)	Inlet Pressure (psi)	ID (in)	MAOP (psi)	OD (in)	Calculated S*t (psi-in)	Picked Pipe Grade	Actual S*t (psi-in)	S*t higher than needed?
748.89	50.8	6	100	6.625	1552.73	STD	11200	YES

S (psi)	t (in)	Real pipe ID (in)	Pipe Weight (ppf)	Pi (psi)	P_milltest (psi)	P_d (psi)	P_test (psi)	0.85(P_milltest) (psi)
40000	0.28	6.065	18.99	410.16	328.13	150	187.5	278.91

P_d < 0.85(P_milltest) ?	P_test < 0.85(P_milltest) ?
YES	YES

Accordingly, the pipe line can be constructed and tested. If the line turns out to fail the field pressure test, the leaks must be repaired until it passes the test. If the line could become pressurized to a value larger than the MAOP, some form of overpressure protection must be built into the entrance to the line. This should not be the case for this project, since the MAOP was already exaggerated from the expected inlet pressure. However, it might be helpful to install the surface safety gate valve with an actuator that will close the valve if MAOP is overcome, just for safety purposes.

The final step is to determine the logistics of how to put the pipeline in place. According to the CODE, the onshore pipeline should be at least 36 inches underground. The pipelines have to also be marked with permanent signs in order to notify and road construction workers for its location. The row must be kept open and leak checks must be monitored regularly. The CODE also specifies that the bore for the pipeline needs to be cased before the pipeline is put in place.

In addition, the pipelines and the joints also need to be coated and wrapped with a seal to prevent corrosion. Internal coating might be necessary in case that corrosive fluids are injected. The welds should also be X-Rayed to verify a high quality weld in populated areas where it is not easy to repair the pipelines. Once the well does not produce any more, the pipeline needs to be removed of any pressure, and it should be flushed entirely with water in order to prevent future blowouts. The pipeline needs to be filled with water before abandonment, since it will be a lot safer drilling into a water filled pipe than other fluid filled pipes.

<u>WATER PIPE</u> (Flow rate = 748.89 STB/day)

After the calculated flow rate of around 748.89 STB/day is acquired and the gas properties are determined, the next step is to design the gas pipeline. The gas specific gravity is inputted from the gas properties and the variable is the pipe diameter. The other parameters are inputted as given, except the inlet pressure that is going to be the result of the calculation. It is important to note that the value for oil flow rate plugged into the calculation is actually 1500 STB/day, which is roughly doubled the value of the calculated flow rate. This is in order to assume for the worst case scenario, in order to make sure that the designed pipeline will not have any problem in the future. The only difference between the inputs for oil and water pipes is that the viscosity of the produced water is assumed to be 1 cP, and that the density is different.

RESET	Fluid Data	
Density	65.55	lbm/ft3
Viscosity	1	cp
	Wellbore Data	
Diameter	8	in
Length	26400	ft
Angle	0	deg
Roughness	0.0006	
	Flow Data	
Pressure Drop	460	psi
Flowrate	1500	Bbl/D

Diameter	Inlet Pressure
4	56.4
4.5	49.3
5	45.5
5.5	43.4
6	42.1
6.5	41.3
7	40.8
7.5	40.5
8	40.3

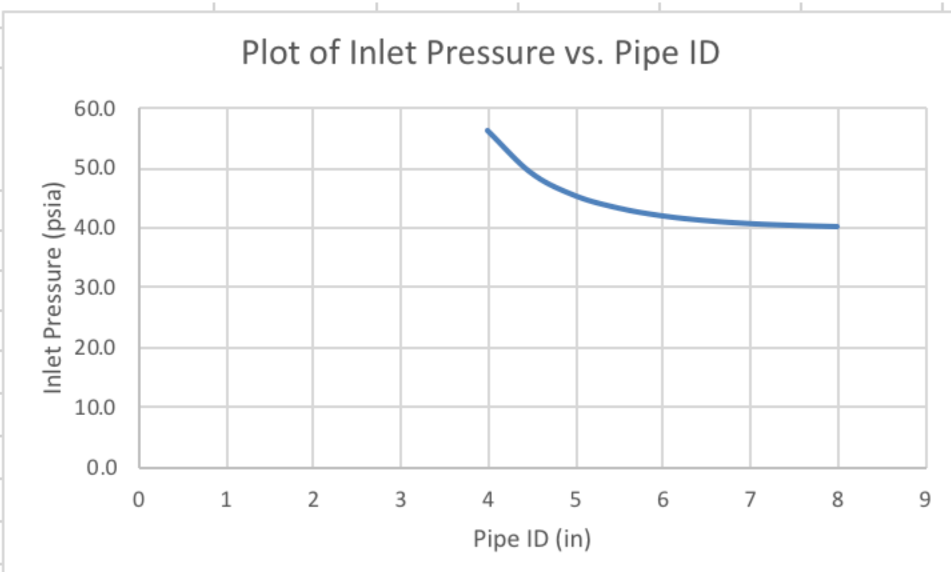


Fig 21: Plot of Inlet Pressure vs. Pipe ID.

Seeing from the plot shown above, the inlet pressure is starting to plateau as the pipe ID gets bigger. Once this happens, the pipe ID is reaching the point of diminishing return and there is no use picking bigger pipes any more. According to the plot, an engineer might pick 6.5 inches as the gas pipe. Picking bigger ID pipes will be a lot costlier and will not be economically reasonable.

The other steps are similar to the steps for determining the oil pipeline. The results are shown as followed,

Table 18.8: Gas Pipeline Design

Design: 7.625" OD, 23.57 ppf, STD, Fillet Weld.

Pipeline	Flow Rate (bbl/day)	Inlet Pressure (psi)	ID (in)	MAOP (psi)	OD (in)	S*t (psi-in)	Picked Pipe Grade	Actual S*t (psi-in)	S*t higher than needed?
Produced Water	748.89	41.3	6.5	80	7.625	1429.7	STD	12040	YES

S (psi)	t (in)	Real pipe ID (in)	Pipe Weight (ppf)	Pi (psi)	P_milltest (psi)	P_d (psi)	P_test (psi)	0.85(P_milltest) (psi)
40000	0.301	7.023	23.57	328.125	262.5	120	150	223.125

P_d < 0.85(P_milltest) ?	P_test < 0.85(P_milltest) ?
YES	YES

The steps for following the CODE and the treatments of the pipes are similar to that of the oil pipe.

GAS PIPE Design (Flow rate = 674 Mscf/day)

After the calculated flow rate of around 674 Mscf/day is acquired and the gas properties are determined, the next step is to design the gas pipeline. The gas specific gravity is inputted from the gas properties and the variable is the pipe diameter. The other parameters are inputted as given, except the inlet pressure that is going to be the result of the calculation. It is important to note that the value for oil flow rate plugged into the calculation is actually 1,400 Mscf/day, which is roughly doubled the value of the calculated flow rate. This is in order to assume for the worst case scenario, in order to make sure that the designed pipeline will not have any problem in the future.

RESET	*Fluid Data*	
Gravity	0.83701	**to air**
CO_2	0.51	**%**
N_2	7.1	**%**
H_2S	2	**%**
H_2O	*0.29*	***%***
	Wellbore Data	
Diameter	2.59	**in**
Length	26400	**ft**
Angle	0	**deg**
Roughness	*0.0006*	
	Flow Data	
Exit Temperature	60	**F**
Inlet Temperature	90	**F**
Exit Pressure	1014.7	**psi**
Inlet Pressure	800	**psi**
Flow Rate	1400	**MScf/D**

Fig 22: Inputs for Calculating Gas Inlet Pressure.

Diameter	Inlet Pressure
2.59	1048.22
4	1018.65
4.5	1016.91
5	1016.01
6	1015.23
8	1014.83

Fig 23: Inlet Pressure for Gas Pipe of Different IDs.

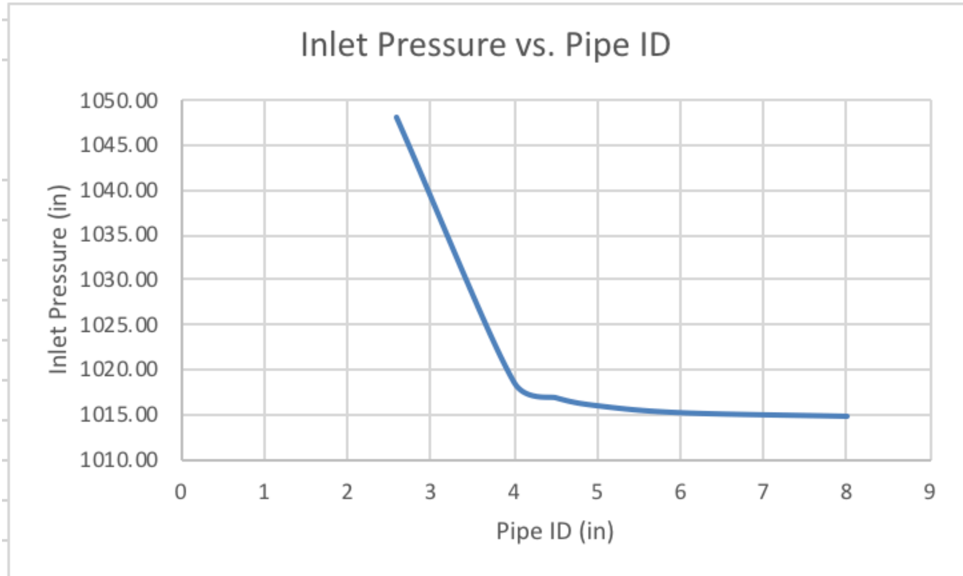


Fig 24: Plot of Inlet Pressure vs. Pipe ID.

Seeing from the plot shown above, the inlet pressure is starting to plateau as the pipe ID gets bigger. Once this happens, the pipe ID is reaching the point of diminishing return and there is no use picking bigger pipes any more. According to the plot, an engineer might pick 5 inches as the gas pipe. Picking bigger ID pipes will be a lot more costly and will not be economically reasonable.

The other steps are similar to the steps for determining the oil pipeline. The results are shown as followed,

Table 18.9: Water Pipeline Design

Design: 5.563" OD, 20.8 ppf, XS, Fillet Weld.

Pipeline	Flow Rate (bbl/day)	Inlet Pressure (psi)	ID (in)	MAOP (psi)	OD (in)	S*t (psi-in)	Picked Pipe Grade	Actual S*t (psi-in)	S*t higher than needed?
Gas	674	1016.01	5	1500	5.563	19557	XS	34560	YES

S (psi)	t (in)	Real pipe ID (in)	Pipe Weight (ppf)	Pi (psi)	P_milltest (psi)	P_d (psi)	P_test (psi)	0.85(P_milltest) (psi)
80000	0.432	5.761	20.8	6152.3	4921.875	2250	2812.5	4183.59375

P_d < 0.85(P_milltest) ?	P_test < 0.85(P_milltest) ?
YES	YES

The steps for following the CODE and the treatments of the pipes are similar to that of the oil pipe.

Scaling

Scaling is basically a deposit or coating formed on the surface of metal, rock or other material. Scale is caused by a precipitation due to chemical reactions, a change in pressure or temperature, or a change in the composition of a solution.

Scaling can be a problem in production overtime as it plugs rock pores, perforation and pipes. It's important to keep track and combat it make the production for well better overtime. The most common oil field scales are Calcium Carbonate (calcite or limestone), Barium Sulfate (barite) and Calcium Sulfate (gypsum or anhydrite).

The best way to determine the scale in the well is to carefully analyze the post completion produce water from the well. Table 19shows the post completion produced water data.

Table 19: Post completion produced water

Temperature (deg F)	180
pH	6.51
Dissolved Component	Concentration (mg/l)
Sodium	33,560
Calcium	1,000
Magnesium	254
Barium	10
Potassium	88
Iron	2
Chlorine	53,000
Carbonate	1,000
Bicarbonate	748
Sulfate	25
Hydroxide	0
Hydrogen	0

Using the data from the above table, the scales are calculated using the scale excel spread sheet on canvas. For calcium carbonate scaling tendency of any water can be determined by calculating the langelier saturation index (LSI). The table 19.1, 19.2 and 19.3 shows the following result.

Table 19.1: Calcium Carbonate scale

Calcium Carbonate	
Tendency	Scaling
A	0.39527295
B	1.087438336
C	3.1496
D	3.35789321
pHs	4.2752
LSI	2.2348

Since the LSI is a **positive number 2.2348**, scaling will surely occur in the well. The smart way to tackle this carbonate scaling is using inhibition. The phosphate inhibitor will be used, which coats the scales and prevents it from scaling on the solid surface. The inhibitor will be mixed with water and injected in annulus with produced fluids at the pump intake in wells that are being pumped with an open annulus (Scale and Corrosion ppt, Bommer). To the deliver the inhibitor scale squeezed is performed. The inhibitor volume absorbed by rock and is mixed with produced fluids overtime. Scale squeeze can last for year or less so continuous lab test of produced fluid is conducted to check if another squeeze will be required. Other methods such as using HCL to dissolve carbonates can be done, but are expensive and will not be used.

Table 19.2: Calcium Sulfate Scale

Calcium Sulfate		
Tendency	Not Scaling	
X	0.02473958	mole/l
K	0.00222	from chart
Solubility	0.07268755	mole/l
eq Ca	0.05	eq moles/l
eq Sulfate	0.00052083	eq moles/l

smallest	0.00052083	eq moles/l

Table 19.3 : Barium Sulfate scale

Barium Sulfate		
Tendency	Not Scaling	
X	-0.00018758	moles/l
K	0.000000047	from chart
Solubility	0.000660011	moles/l
eq Ba	0.000145666	eq moles/l
eq Sulfate	0.000520833	eq moles/l
smallest	0.000145666	eq moles/l

For predicting calcium and barium sulfate scaling tendency, the solubility of the ion in water sample is determined. If the amount that can be solubilized is larger than what is measured in the water sample then there will be no scale forming (Scale and Corrosion ppt, Bommer). Examining the data, the barium and calcium sulfate scaling won't occur in the well.

However, it is possible that the scale might form from a mistake or error in pumping fluid or other miscellaneous processes. The scaling of barium sulfate can only be mechanically removed. Thus, it's important to be careful as water with barium should never mix with sulfate. The calcium sulfate scale can be removed by first converting it into calcite by injecting ammonium carbonated and then HCL acid to dissolve it. The scale can definitely harm the production system overtime and it's important to make sure that the lab test are done frequently to determine when and which inhibitor to inject.

Artificial Lift

Usually when a new oil well is producing, it will have enough energy to lift the fluid up from the reservoir. However, as the well ages, it will lose pressure and its capability to lift the fluid up from the reservoir reduced drastically. In total, this project will supply roughly 2,200 Bbl/day, including oil, water, and gas. The required power to lift the fluid up is calculated by the following formula:

$$HHP = \frac{q\left(p_{wf} - p_T\right)}{58,771}$$

$$HHP = \text{ hydraulic horse power}$$

$$q = \text{ flow rate } (\text{Bbl/day})$$

$$p_T = \text{ flowing pressure at the top } (\text{psi})$$

$$p_{wf} = \text{ flowing pressure at the bottom } (\text{psi})$$

In this case, q is 2,200, flowing pressure at bottom (BHP) is 4850 psi, and in order to assume the worst case scenario, which is when the required power is maximized, the flowing pressure at the top will be assumed to be 0 psi. Thus, the calculations for HHP can be done as the following:

HHP = 2,200 * (4,850 – 0) / 58,771

HHP = 181.55 hp

As the well ages, the flow rate will go down. Even though the 2,200 Bbl/day is still available within the reservoir, the well does not have enough power to lift the amount up. Thus, there is a need to find some help to lift the fluid up. This is when the process of artificial lift will take place.

Artificial lift is simply the idea or process used to help lift the fluid up from the reservoir, since the well cannot supply enough pressure difference. Roughly 92% of the wells in the US are utilizing artificial lift. There are several available artificial lift types including:

- Beam Lift
- Gas Lift
- Electric Submersible Pumps (ESP)
- Progressing Cavity Pumps (PCP)
- Hydraulic Pumps (Piston and Jet)

Though there are a variety of options, there are commonly two main options that engineers pick as the artificial lift system, which are the pump lift and the gas lift.

The pump lift creates enough discharge pressure for the fluid to flow up to the surface. The pump lift is designed especially to process liquid flows. The most known pump lift method is the Beam Lift, the Rod Pumps and the Sucker Rods. The main issue with the beam lift is that is designed for liquid flow. However, in this Bakken well, there will definitely be some gas flow from the solution gas, and the flow rate of gas is far from negligible. Thus, the pump lift might create an issue, which can be treated by closely monitoring the process closely. The pump lift can also have an issue with solid formations. There is a possibility that some amount of sand will come out of this well, and the pump lift system can be damaged by the sand.

Gas lift is also commonly found in the field, accounting to 10% of all the artificial lifted wells. Gas lift is the only method that does not use a pump. Instead, it applies the idea of injecting gas to reduce the density of the fluid. The fluid flowing back up to the well from gas lift includes the reservoir fluid plus the injected gas. The main advantage of the gas lift is that is cheap, and it does not require any pumps. However, it will require an outside source of gas that will be injected into the well. This outside gas can either be the produced gas or the purchased gas.

Even though the beam lift accounts for 85% of the wells under artificial lift, it is desirable for this Bakken well to use gas lift. This is because gas lift is less likely to create any problem, seeing from the figure shown below.

Lift Type	No. Wells	%	Failure
			Rate/yr
Rod Pump Failure	409,974	85.2	0.57
Sucker Rod Failure			0.44
ESP	9,738	2.0	0.35
Hydraulic	9,740	2.0	1.86
Gas Lift	51,964	10.8	0.21
Total	481,416	100	

Fig 25: Statistics of Lift Failures (Bommer, 2018).

Due to its failure rate, gas lift will be chosen for this well. Once the gas lift is picked, the next issue is that the gas lift would need a special tubing to lift up the fluids. This is where the production tubing is needed in this project.

In a usual case, an engineer would need to install packers in order to support the installment of the tubing. However, this Bakken well already has packers installed since the beginning in order to protect the 7" casing. Thus, this packer will be able to support the tubing for artificial lift. There are a few types of tubing. Since there is a very limited data in terms of the parameters required for calculating the specification of the tubing, an engineer might stay on the conservative side and pick the widely used 2 7/8" tubing for this gas lift process. This tubing will run from the packer to the wellhead.

Recompletion

After the well has been producing for some time, which is going to be a number of years or decades, the specific site of this Bakken Reservoir will be depleted. At that period, the well is not economically producible any more. However, an engineer can still design a recompletion task in order to boost the recovery up and thus keep the well in production.

The Mission Canyon has mud logger, favorable open hole well logs, and supporting sidewall cores data available to the engineer. The engineer is given the following data to consider the recompletion opportunity:

Depth to top of Sand = 9450 ft
Sand Thickness = 12 ft
Average Core Porosity = 14%
Average Core Permeability to Air = 16 md
Average Log Water Saturation = 50%

Since there is no previous production data available, the initial guess of the reservoir area is 40 acres. Additionally, the Mission Canyon predicted that the probable reservoir drive mechanism would be the solution gas expansion and they found that the recovered fluid from the core is 30 degrees API.

The first step is to calculate the oil properties, especially Bo from the reservoir. The calculations are shown below:

RESET	*Fluid Data*	
Oil Gravity	30	API
Gas Gravity	0.83701	
Water Gravity	1.07	
Gas/Liquid Ratio	350	Scf/STB
Water/Oil Ratio	1.6	bbl/bbl
	Reservoir Conditions	
Pressure	4668.3	psi
Temperature	240	F
Pressure Increments	100	psi
	Separator Conditions	
Separator Temperature	180	F
Separator Pressure	100	psi

Properties At Bubble Point		
Bubble Point Pressure	4533.57	psi
Liquid Density	56.6792	lbm/ft3
Liquid Viscosity	0.31038	cp
Bo	1.43227	Bbl/STB
Rs	910	Scf/bbl

The Bo of this remaining oil is around 1.4, resulting from the attempt to match the bubble point with the initial bubble point. Even though the bubble point might change when the reservoir is depleted, it is assumed in this case that the bubble point remained fairly constant and thus an engineer would obtain the stated result.

The next step is to calculated the hydrocarbon in place from the depleted reservoir. The hydrocarbon volume are calculated from the Porosity * (1 – Sw) * Reservoir Volume and the results are as followed:

Reservoir Area	40	acres
Reservoir Area	1.74E+06	ft^2
Sw	0.5	
Porosity	0.14	
Net Pay Thickness	12	ft
Pore Volume	2.93E+06	ft^3
Hydrocarbon Volume	1.46E+06	ft^3

Now, the expected hydrocarbon production at 100% is 1.46E6 ft^3, or 2.61E5 barrels. However, the solution gas drive will never give a 100% recovery factor. Thus, an engineer would refer to the following table to determine the actual recoverable oil by solution gas drive.

Producing Mechanism	Oil Recovery Range (% OOIP)
Solution-gas drive	10 to 25%
Gas-cap drive without gravity drainage	15 to 40%
Gas-cap drive with gravity drainage	15 to 80%
Gas reinjection with gravity drainage	15 to 80%
Gas reinjection without gravity drainage	15 to 45%
Waterdrive	15 to 60%

Recovery Factor for Drive Mechanisms (Petrowiki, 2015)

Thus, the oil recovery is calculated as followed:

Low Recovery Factor (0.1)

Oil in Place	2.61E+05	Barrel
Recovery Factor	0.1	
Bo	1.43227	RB/STB
Recoverable Oil	1.82E+04	Barrel
Oil Price (5/3/2018)	68.5	$
Income	1.25E+06	$
Cost	100000	$
Profit	1.15E+06	$

High Recovery Factor (0.25)

Oil in Place	2.61E+05	Barrel
Recovery Factor	0.25	
Bo	1.43227	RB/STB
Recoverable Oil	4.55E+04	Barrel
Oil Price (5/3/2018)	68.5	$
Income	3.12E+06	$
Cost	100000	$
Profit	3.02E+06	$

Based on the oil price of $68.5 on May 3, 2018, in either case, the profit will vary from 1.15 to 3.02 million USD. Thus, it is very desirable for this project to attempt the recompletion. Indeed, the recompletion will add quite a substantial profit to the project.

In addition, an engineer might assume that the fracture does not require any stimulation. However, it might be very helpful to fracture more stages in order to allow better flow and thus maximize the recovery. An engineer might say that the perforation job will be roughly similar to the initial peroration, and uses the following perforating tool.

Fig 26: Perforating Gun for Recompletion.

Plugging and Abandoning (P & A)

When the well stops producing and making money, it is time to perform recompletions, to trade it or to plug and abandon. Recompletions and plugging comes with a cost and no returns. For our case, its highly likely that the well will be sold as soon as the future has no scope. However, if the trading fails and the recompletions cost is high, the plugging has to be considered. Plugging is required under the regulations of the governing body.

The main reasons for the plugging and abandoning is basically to prevent contamination of oil and gas bearing formation and to prevent contamination of usable water and to contain similar fluids to within geologic intervals (Bommer). The North Dakota state regulators will give guidelines for plugging a well.

It is also crucial to make sure that the cementing is properly done. The cement will be used to plug the well. Eventually the soft sediments that are not supported by cement casing gradually collapse, which helps it to get it plugged. It is also possible that the well gets unplugged due to acid corrosion or injections in other well that are exceeding the cement plug strength. In that case the re-plugging is required. After plugging the well, the site is restored and all the equipment is cleared.

The usual cost of plugging of the well is up to hundreds and thousands of dollars and its always a smart idea to sell the well when it has no future scope in production. Doing that, a lot of money can be saved. Thus, if there is a trading opportunity, the well will be sold. The figure # is obtained for epa.gov, shows a sample contract of plugging in South Dakota.

Fig 27: Plugging Contract in South Dakota

Item	Estimate
Plugging materials	$ See note below
Description of materials: Class C Cement (bulk)	
Equipment	$ Included
Types and quantity of equipment to be supplied: 20 bbl cement tank, 5X8 Duplex Pump Coil Tubing Unit	
Labor	$ Included
Crew description: 3 Man	
Other	$ 1,000 per well
Explanation of Other: $1000.00 per well, Powertech provides the cement	
Estimate Completion Time: 3-4 wells per day	Total Estimate: $ 100,000.00

References

Bommer, P. (2018). *Flow in Pipes*. Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). *Multiphase Flow.* Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). *Well Heads, Flow Control & Facilities*. Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). *Pipeline Design & Flow Assurance*. Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). IPR, VLP & Damage. Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). *Scale and Corrosion*. Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). *Completion Types and Fluids*. Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). *Packers*. Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). *Perforating*. Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). *Acidizing*. Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). *Fracturing Theory*. Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). Fracturing Design $ Monitoring. Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). *Artificial Lift Concepts*. Lecture presented at UT Austin, Austin, TX.

Bommer, P. (2018). *Closing Out a Project*. Lecture presented at UT Austin, Austin, TX.

Scanlan, W.P., et al. (2018). Optimizing of Bakken Well Completions in a Multivariable World. Society of Petroleum Engineers, 184828.

Weddle, P., et al. (2017). Mining the Bakken: Driving Cluster Efficiency Higher Using Particulate Diverters. Society of Petroleum Engineers, 184828