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Abstract

Scale buildup is a common problem in oil and gas producing wells all over the world. It gives difficulties to both the production of oil and gas, as well as well intervention operations. The buildup of scale generates more intervention work due to for example scaling of down hole safety valves and scale-buildups inside the production tubing.

Scale can be divided into two main types, organic and inorganic scale. Organic scale is present in the beginning of a reservoir's life, while inorganic scale is present later in the reservoir's life, when it is more mature. Waxes and asphaltenes are examples of organic scale, while carbonates and sulphates are examples of inorganic scale. Calcium carbonates, $CaCO_3$ and $BaSO_4$ are common types of inorganic scale in the North Sea.

This thesis focuses on finding the real coefficient of friction in an oil producer in the North Sea. It uses simulation data and real time data from an offshore operation performed in February 2022. It gives a brief introduction to the theory behind coefficient of friction, scale and black sticky stuff (BSS). It also presents wireline equipment and how it works in an offshore operation

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Kristine Nærland

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Abbreviations

AOD = add on drum

BCU = BOP control unit

BF = buoyancy factor

BHA = bottom hole assembly

BOP = blow out preventer

BSS = black sticky stuff

CCL = casing collar locator

CSD = completion schematic diagram

DHSV = down hole safety valve

FF = friction factor

GIH = grease injection head

GLV = gas lift valve

HUD = hold up depth

KOT = kick over tool

LBS = pounds

MD RKB = measured depth rotary kelly bushing

PCE = pressure control equipment

POOH = pull out of hole

PSI = pound per square inch

PW = pulling weight

QTS = quick test sub

RIH = run in hole

RW = running weight

SG = specific gravity

SIWHP = shut in well head pressure

SPM = side pocket mandrel

TC = toolcatcher

TVD = true vertical depth

VOC ppm = volatile organic compounds parts per million

WCC = winch control unit

WCU = well control unit

WHP = well head pressure

Introduction

Offshore platform Phoenix 14 was built in Norway and started the production in mid of the 1980's. It is placed in the North Sea on the Norwegian continental shelf. The platform is a concrete deep-water structure with four shafts. The reservoir the platform produces from, is about 2500 to 3000 meters deep.
The platform has both production facilities, living quarter and a derrick. At average there are around 150 people onboard.

Two of the shafts are for wells. There are 42 well slots onboard, with both water injectors and oil and gas producers. The well slots are located north and south, with 21 slots on each side. The wellhead area can easily be accessed from the intervention decks. There is only a staircase down. On Figure 1 below, you can see up to the intervention deck where the wireline equipment is placed. Behind the small white tank in the lower left corner, the staircase to the well head area can be entered.

Figure 1: Intervention deck offshore

There is not a continuous wireline activity ongoing on the platform. From 2016 to 2021, the average days with well operations were 109 days and with an average of 23 jobs performed each year. The jobs performed lasted from 1 day to 20 days, depending on the operation conducted.

The most common operations performed on this rig, is replacing down hole safety valves, replacing gas lift valves and performing caliper runs. On operations where the down hole safety valve is going to be replaced, it is common to find debris above the valve. That means a lot of broaching and bailing to remove the debris and be able to reach the safety valve.
There are also operations pre and post drilling operations. For example, pre plug and abandonment operations to secure the well, before drilling removes the completion string and preparing for recompletion. When the drilling crew has finished a recompletion, the wireline crew must rig up the intervention equipment to remove pre-set plugs in the completion string. Sometimes the completion string is not perforated before it is set, then wireline must run perforation guns to achieve contact between the production tubing and the reservoir.

Scale

Scale is a real problem in the oil and gas industry all over the world. In the beginning of the 21st century, the economic impact of scale was estimated to be more than 1.4 billion USD each year (Frenier & Ziauddin, 2008). This is due to lost production and damage to equipment. The problems scale can cause is corrosion of tubing, flow restriction and formation damage due to build-ups in tubulars and pores and damage to down hole equipment. Build-ups in the down hole safety valve (DHSV) can cause the flow tube in the valve to not properly slide and obstruct the valve to close properly. This can be serious, since the DHSV is the primary barrier against the reservoir in an emergency shut down.

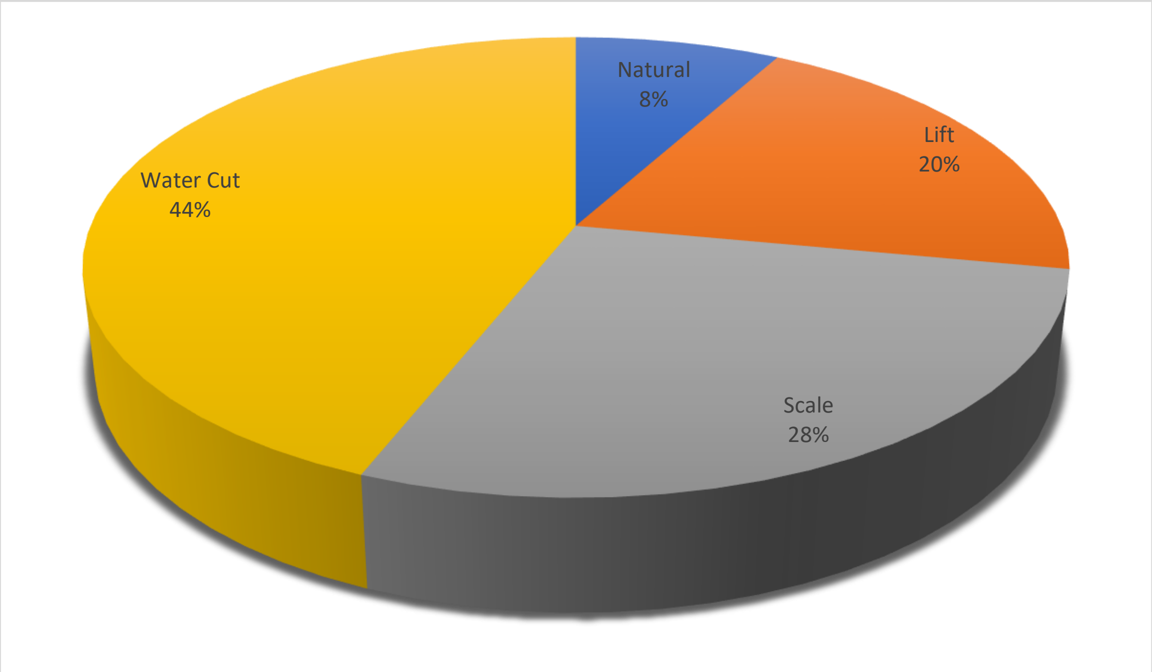


Figure 2: Impact of scale; percentage of loss of production from each process (Frenier & Ziauddin, 2008)

The root cause of scale formation is usually a change in one or more equilibrium conditions that allows an insoluble product to form. Before drilling a well, the formation is in equilibrium. When drilling and completion takes place, mud, completion fluids or water injection is introduced and the equilibrium system in the formation will be disturbed. The production also causes change in pressure and temperature (Bellarby, 2009).

There are two main types of scale: organic and inorganic. Organic scale deposits come from the gases, crude oil, or reactions of the crude oil. Examples of organic scales is waxes, asphaltenes, gas hydrates, hydrate properties and naphthenate salts. This type of scale usually forms in the beginning of a reservoir's life. Inorganic scales are minerals that form on a surface because of the saturation of the local environment with and organic salt. Inorganic scale deposits usually form later in the reservoir's life when it is more mature.

The two main types of inorganic scale are carbonate scales and sulphate scales. Carbonate scales, $CaCO_3$, such as aragonite, calcite and vaterite, are often found throughout the whole well. From near wellbore region, fractures, sandpacks and screens, to downhole equipment, tubulars, and surface equipment. It forms during production of formation water and injection of produced water or treated seawater. Calcite is the most common type of carbonate scale and forms quickly. It forms from the reaction of calcium (Ca^{2+}) ions with carbonate (CO_3^{2-}) with the following reaction

$$Ca^{2+} + CO_3^{2-} \rightarrow \ CaCO_3$$

As mentioned, pressure has a major effect on calcium carbonate scaling tendency through two mechanisms. Firstly, a reduction in pressure leads to CO_2 lost from the solution. Secondly, reducing the pressure reduces the concentration of CO_2 in the solution. (Bellarby, 2009). To avoid the formation of calcite scale, you can try to keep a high pressure in the tubing. As well as treating the well with scale inhibitor treatment.
Calcite scale can be removed by acids, such as hydrochloric acid. This acid reacts fast with the calcite scale and has a low cost.

Sulphate scales forms during the mixing of incompatible waters, such as seawater and formation water. The main cause of sulphates is when the solubility product of a salt is excessed in a local environment. Sulphates are found most of the same places as the carbonate scales, except it is rarely found in the surface equipment. It can also form in the matrix, perforation, screens, tubing and connection lines (Frenier & Ziauddin, 2008). Examples of sulphate scales is calcium, strontium and barium sulphate. The most common, and most problematic is the barium sulphate, $BaSO_4$. On Figure 3 to the right, you can see an example of barium sulphate scaled-up in a tubing.

Figure 3: Barium sulphate scaled-up in tubing (Bellarby, 2009)

On the field studied in the case described later, calcium carbonate is mostly found shallow in the wells, and barium sulphate are found deep in the wells – closer to the reservoir. See Figure 4.

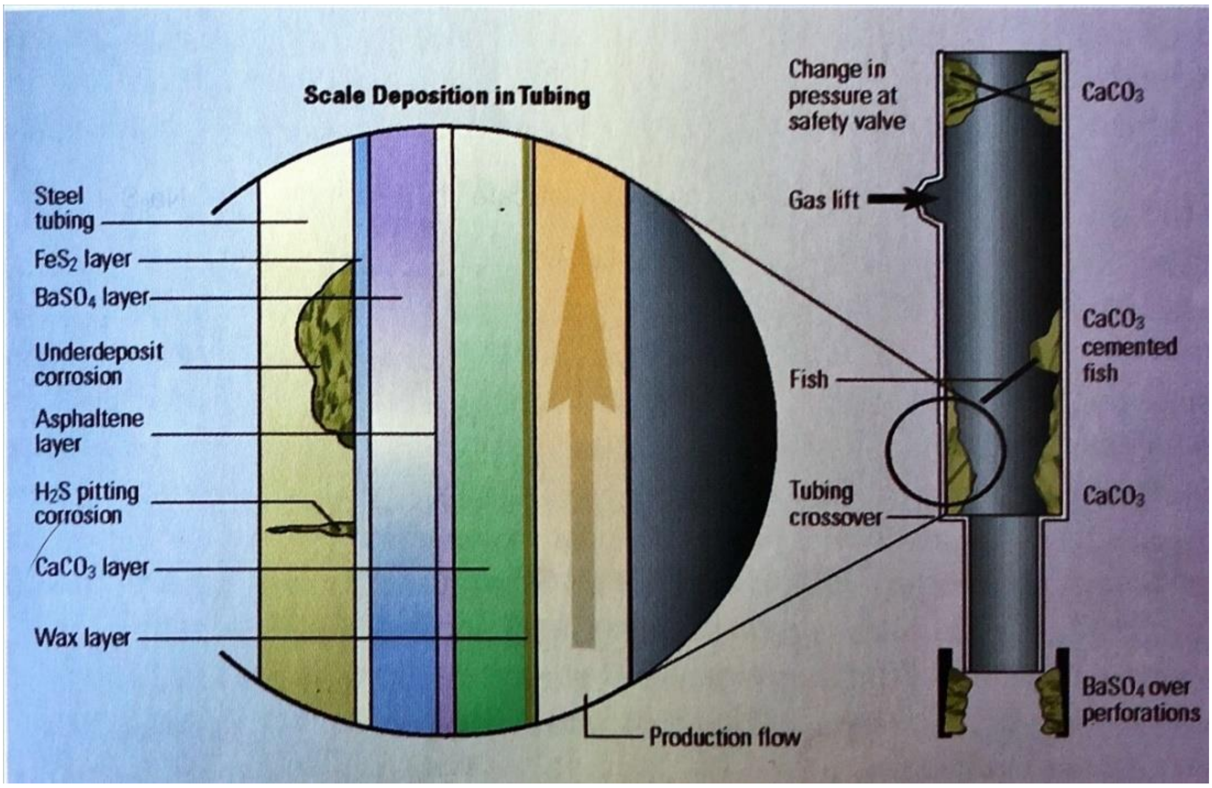


Figure 4: Scale formation in a well (Frenier & Ziauddin, 2008)

Black sticky stuff

Black sticky stuff (BSS) is a type of organic scale that is present at the oilfield we are looking at. It is similar to asphaltenes.

Asphaltenes are organic solids precipitated from crude oil systems and looks like black coal or coke-like deposits. They can be deposited in the tubing, cause operational problems and be hard to remove. A report from the UIa field in Norway, shows that the down hole safety valves became harder to open due to the increased friction between the flow tube and the valve. The asphaltene content of Ula was only 0.57 per cent (Bellarby, 2009).

The black sticky stuff we are looking at, contains approximately 70 % iron sulfide, up to 15 % crude oil and up to 0,15 % benzene. It also contains other components. The cause of BSS is mainly from the use of a specific scale inhibitor treatment at the field in 2010. The scale inhibitor treatment had a very low pH value, which caused corrosion in the wells. It can be dangerous to both human and animals. It is a carcinogenic agent, and it can cause hereditary damage.

In contact with acids, noxious fumes can develop. For example, hydrogen sulfide (H_2S). In Figure 5 there is some BSS deposits from a well offshore.

Figure 5: Black sticky stuff (BSS) from a well offshore

Friction coefficient

The coefficient of friction is the ratio of the frictional force resisting the motion of two surfaces in contact to the normal force pressing the two surfaces together (Gregersen, u.d.). The mathematical formula is

$$\mu = \frac{F}{N} \tag{1}$$

where μ is the Greek letter mu for friction coefficient, F is the frictional force and N is the normal force

In well intervention, the friction coefficient is used to determine the amount of weight needed on the bottom hole assembly to overcome gravity, well pressure and friction. When planning an intervention job, we want to know how far down in the well the tools will be able to go, only by gravity.

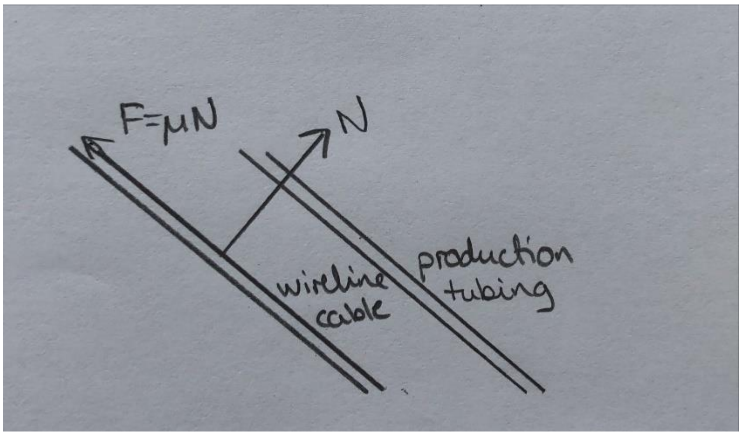


Figure 6: Friction in wellbore

To calculate at which well inclination the tools will stop, we can derive Equation 1, and find Equation 2. See derivation below

$$\mu = \frac{F}{N}$$
$$\mu = \frac{w * L * \cos\alpha}{w * L * \sin\alpha}$$
$$\mu = \frac{\cos\alpha}{\sin\alpha}$$
$$\frac{1}{\mu} = \frac{\sin\alpha}{\cos\alpha} = \tan\alpha$$
$$\tan^{-1}\left(\frac{1}{\mu}\right) = \tan^{-1}(\tan\alpha)$$
$$\alpha = \tan^{-1}\left(\frac{1}{\mu}\right) \tag{2}$$

‘’Any time a change in the direction of the well takes place, the friction becomes a function of the tension in the string, not only the weight itself. To minimize friction, the number of direction changes in the well path should be kept to a minimum.’’ (Khosravanian & Aadnøy, 2021)
By keeping the changes in direction of the well path to a minimum, the intervention string will be able to go further into the well, without the use of a well tractor.

In planning of well intervention operations, it is important to use an accurate coefficient of friction. If it deviates a lot from the real data, it can cause misruns and not being able to perform the planned operation.

Well intervention

The purpose of well intervention is to extend the life of a well and a field. This is done by maintenance, repair, or replacement of existing equipment. The main goal is to make the well produce for a longer period and optimize the production. We can divide well intervention into two main methods: light well intervention and heavy well intervention. Light well intervention is performed in a live well where the well head pressure (WHP) is monitored. Examples of light well intervention is wireline, coil tubing and pumping.

Heavy well intervention is larger operations where the Christmas tree must be removed to do larger workovers. This type of work is performed to a secured well, where there often are mechanical barriers together with a heavy well fluid. The mechanical barriers can be different types of plugs. The Christmas tree is the primary barrier while producing. To be able to remove it, the barrier envelope must be moved further down, to maintain at least two barriers against the reservoir. Examples of heavy well intervention can be recompletion or replacement of the Christmas tree.

Wireline

One of the light well intervention methods is wireline. Wireline is performed during the whole lifetime of a well: from cement logging of a brand new well that is being drilled, maintenance and repairing during the production phase to preparing for plug and abandonment in the end of the production time.

Wireline is a well intervention method where you lower a bottom hole assembly (BHA) into the well by gravity. The BHA can consist of different types of tools, to perform different types of operations. More about BHA on page 25. There are mainly two types of wires used: slickline and braided line. Slickline and braided dyform wire are used to perform mechanical work and for fishing operations. The braided dyform wire does not have an electric conductor. Electric line has an electric conductor and is used for logging and tractor operations. The electric wire can send continuous data to surface while running in or out of the hole. The braided wires are stronger, the breaking strength are higher than for slickline.
Wireline is a cheaper and lighter intervention method than coil tubing. The equipment can be rigged up in a short amount of time – approximately in a day or two. The equipment is also smaller compared to for example coil tubing, which is an advantage at an offshore platform.

When the wireline pressure control equipment is rigged up on the well, the barrier envelope is moved upwards. The primary barrier will be the grease injection head (GIH) or the stuffing box – depending on the operation is performed with braided line or slickline. The secondary barrier will be the blow out preventer (BOP). Compared to the heavy well intervention methods, the well does not have to be secured before the operation can start.

Surface equipment

The wireline surface equipment consists of a winch control cabin, power pack, add on drum, BOP control unit and well control unit. The surface equipment is used to perform the wireline operation, by running the wire, maintain well control and monitor pressures.

The winch control cabin (WCC) is the cabin where the wireline personnel control the speed of the drums with wire. The cabin is equipped with different panels called Smart Monitors, to keep track of depth and weight of the bottom hole assembly, monitor well head pressure and grease pressure and operate the blow out preventer if necessary. The main panel with depth control, speed and tension control is shown in Figure 7. The winch operator must be always aware of the different parameters – to discover any changes that can have a positive or negative effect on the operation.

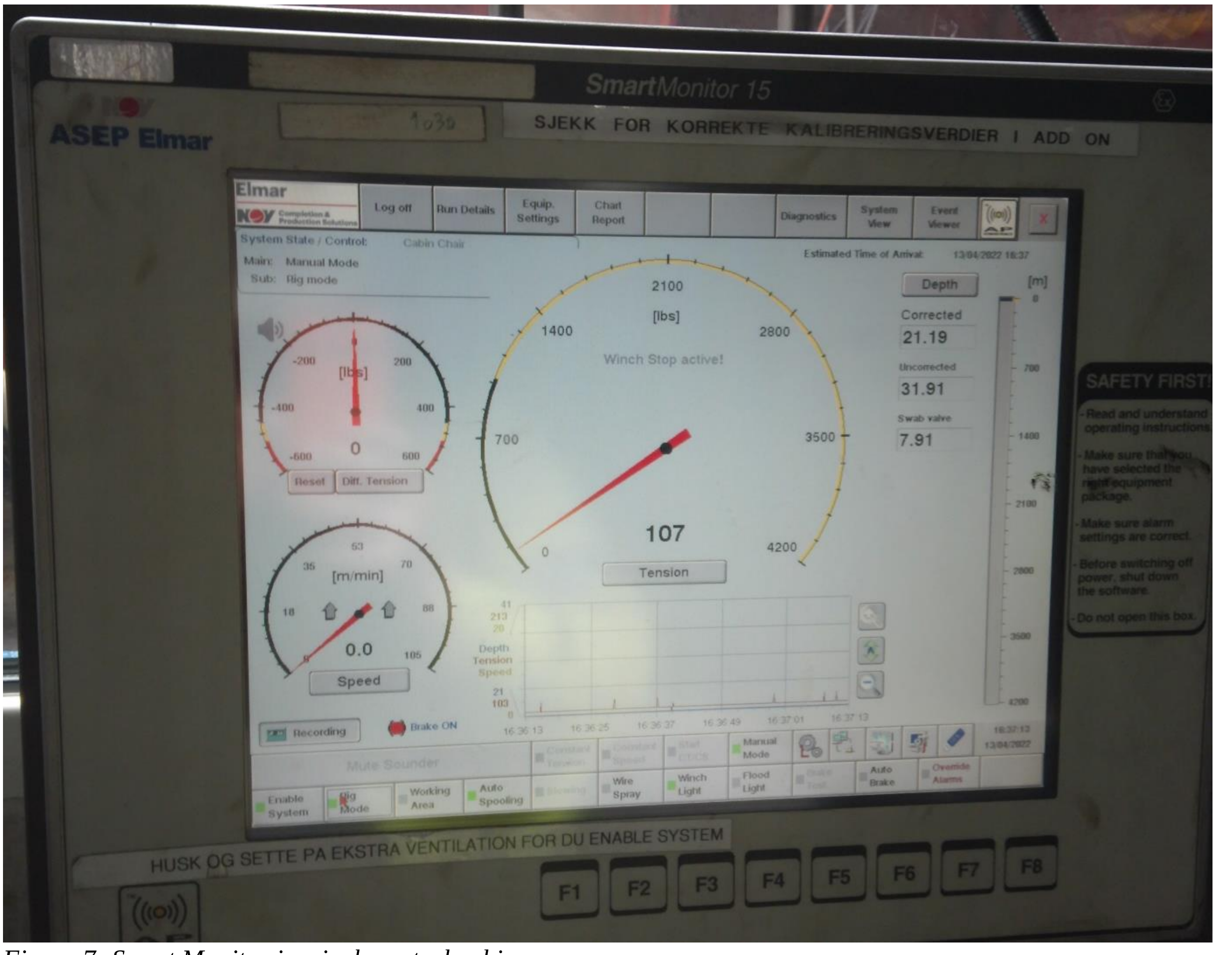


Figure 7: Smart Monitor in winch control cabin

On Figure 8, the blue container to the right is the winch control cabin.

The power pack is the unit that supplies power to the surface equipment. The power pack is connected to an outlet on the wall at the rig, and supplies power to WCC, BOP control unit and well control unit. On Figure 8 the power pack is the container in the middle.

Figure 8: Winch control cabin, power pack and add on drum offshore

The add on drum (AOD) is the unit where the drums with cable are located. The AOD has a depth and tension counter system, that sends signals to the panels in the cabin. Most often there are two drums in the AOD, one with slickline and one with braided electric line. With older equipment, the AOD must be placed right in front of the cabin to be able to see the drums. In newer equipment the AOD can be located further away, with cameras connected to the cabin. See Figure 9 below.

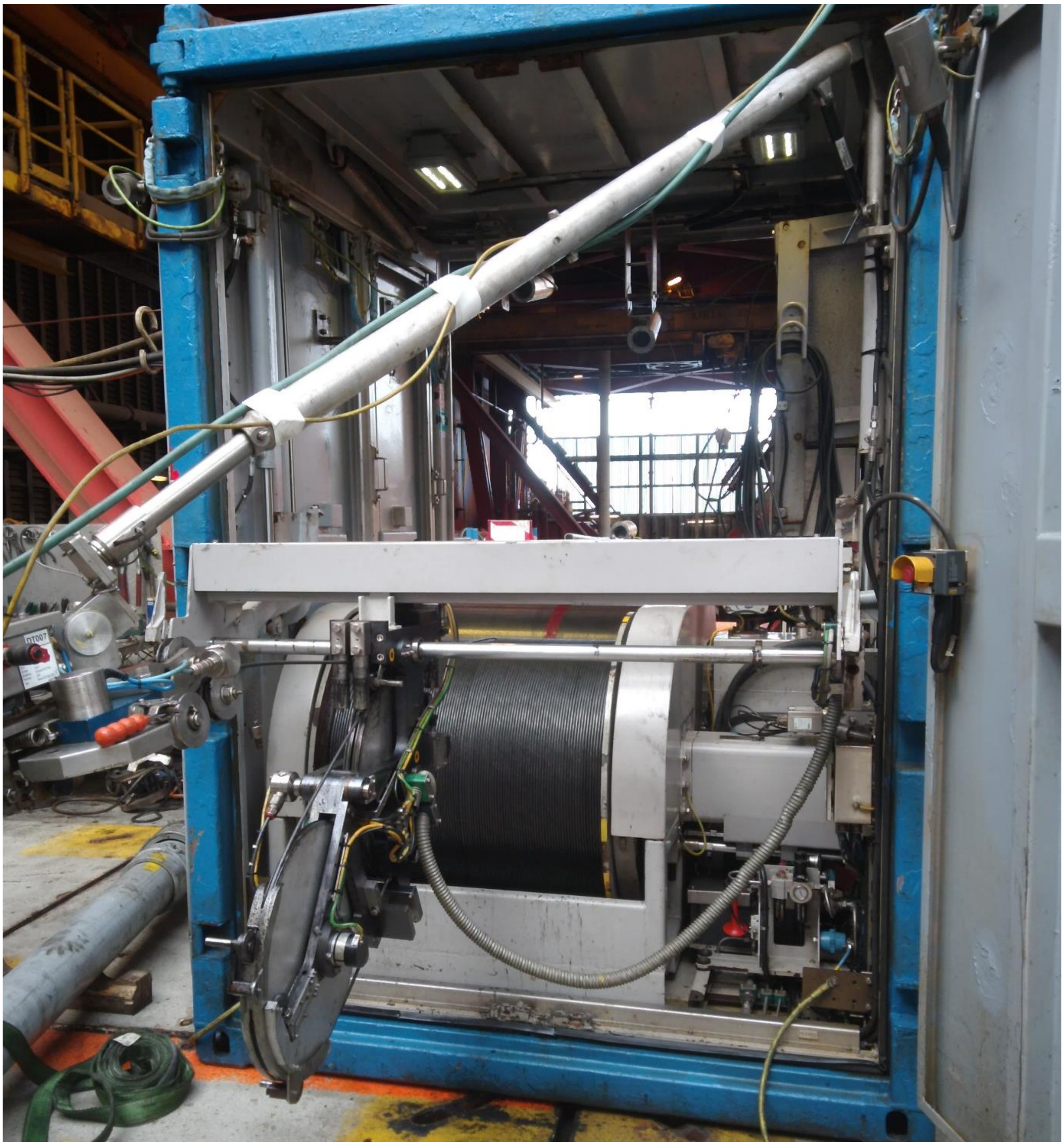


Figure 9: Add on drum offshore

The BOP control unit (BCU) controls the BOP. It supplies hydraulic oil to the BOP rams, and grease to inject between rams if necessary. The BCU can be controlled locally from the panel on the unit, or remote from the winch control cabin.

The well control unit (WCU) controls the grease pressure on the grease injection head (GIH), hydraulic oil to the stuffing box and toolcatcher (TC) and the pressure test pump. It also has sensors for well pressure and grease pressure. The WCU, like the BCU, can be controlled locally on the unit, or remote from the winch control cabin. The network cable from the WCU to the WCC makes it possible to always monitor pressure in the well and in the grease injection head.

Pressure control equipment

Pressure control equipment (PCE) is used to be able to perform work on a live well. It is used to keep the well pressure away from open air. There are different pressure ratings on the PCE. The most common ratings in Norway are 5,000, 6,500, 10,000 and 15,000 pound per square inch (psi). It is the maximum well pressure on the actual job that define the size of the rating on the equipment. It should be at least 1.2 times higher than the maximum achievable well pressure. In Figure 10 you can see a typical rig up with pressure control equipment for braided line.

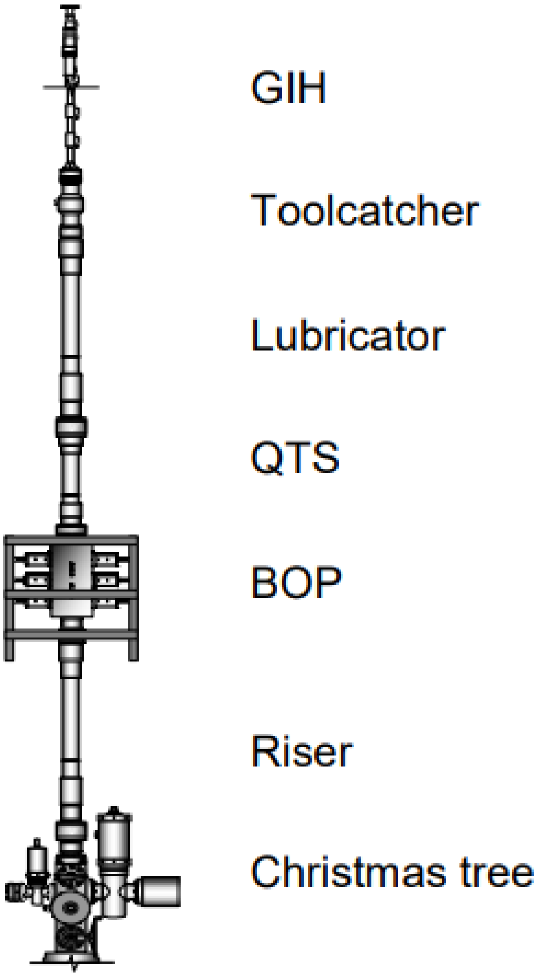


Figure 10: Pressure control equipment

Starting closest to the well, connected to the Christmas tree, we have the riser. The riser is a pipe that connects the Christmas tree to the wireline BOP. It is used to obtain a distance from the valves in the tree and the valves in the BOP. The tree and the BOP are often located at two different levels, with the tree at the well head area and the BOP at the hatch deck. It is preferable to have as few connections as possible between these two, two minimize the amount of possible leak points.

The BOP is short for blow out preventer. In a wireline operation, the BOP is the secondary barrier in the barrier envelope. The BOP consists of three rams: upper blind ram, middle blind ram inverted and shear and seal ram. The upper blind ram holds pressure from below, while the middle ram is inverted, which means it holds pressure from above. During a normal operation, the BOP will not be operated. It is only used in an emergency. For example, you can have an abandon platform situation, and the well needs to be secured. Then you must use the shear and seal ram to cut the cable, and then close the Christmas tree and down hole safety valve (DHSV). Another example is if you have a fixable leakage above the BOP, you can close upper and middle ram, and inject grease between the rams. Then you move your primary barrier to the rams in the BOP and can fix the leakage above before continuing the operation. The reason for injecting grease between the rams, is to avoid gas migrating through the braided line and up in the working environment.

Right above the BOP we have a quick test sub (QTS). When changing from one bottom hole assembly to another, you break the lubricator at the QTS. By doing so, you do not have to do a full rig up test afterwards, you only perform a test between the two o-rings in the QTS.

Figure 11: BOP, QTS and lubricator offshore

The lubricator is the same type of pipe as the riser. The only difference between them is where they are located. The riser is always below the BOP and the lubricator is above. The lubricator can vary in length, depending on the available rig up height and the lengths of the

bottom hole assemblies that will be used. On Figure 11 above you can see the blow out preventer, quick test sub and lubricator rigged up on intervention deck offshore.
On top of the lubricator, you have the toolcatcher (TC). The TC has grapples inside, to stop the BHA from going further up in the grease head when it is pulled out of hole by the winch operator.


Figure 12: Lubricator, TC and GIH offshore

The grease injection head (GIH) is the primary barrier during a normal operation with braided line. It consists of flow tubes with an inner diameter slightly above the outer diameter of the wire, approximately 0.004 to 0.008 inches bigger. The flow tubes are small pipes that are mounted inside the GIH. There are two grease inlets where grease is injected at a constant pressure, mainly a differential pressure up to 70 bars above the well pressure. Each flow tube has a pressure loss between 55 and 100 bars over them. The maximum shut in well head pressure (max. SIWHP) decides how many flow tubes an operation requires. On Figure 12 to the right, you can see the lubricator, toolcatcher and grease injection head rigged up offshore. The grease hoses and hydraulic hoses connected to the toolcatcher and grease injection head, are connected to the well control

unit on the hatch deck.
The rig up hangs in the wireline crane, so it can be lifted and moved to the side to be able to change the bottom hole assembly.

On top of Figure 12 on page 23, you can see the hay pulley. The wireline cable goes from the add on drum, through a hay pulley on hatch deck, up through another hay pulley in the wireline crane before it goes down through the grease injection head and into the well. The hay pulleys are dimensioned according to the size of wireline cable to be run.

When running slickline, the pressure control equipment is almost the same, the only change is replacing the grease injection head with a stuffing box. The stuffing box has rubber packing inside, which seals around the wire to prevent a pressure leak.

Bottom hole assembly

The bottom hole assembly (BHA) are the tools connected to the end of the wire by a rope socket. The main components of a mechanical BHA are rope socket, stem and mechanical jar, as shown in Figure 13. The stems are weight bars used to overcome the friction in pressure control equipment and well pressure by gravity. The mechanical jar is a hammer that gives force upwards or downwards, depending on which way the wire is run.

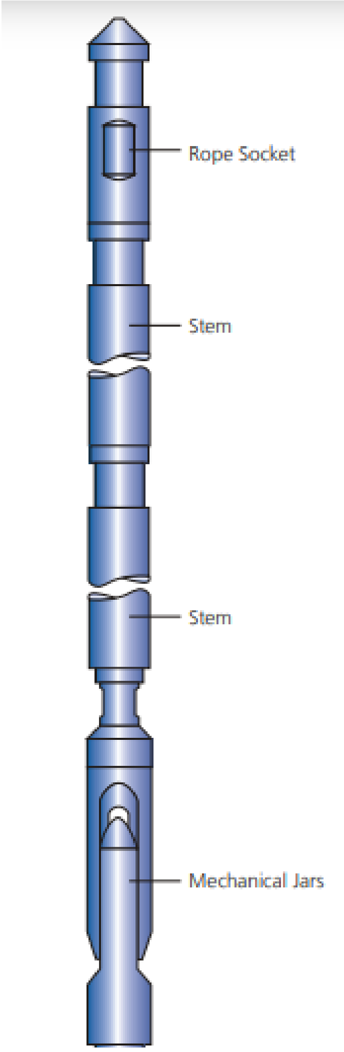


Figure 13: Mechanical BHA (Leutert, 2010)

At the end of the basic BHA, you can use a lot of different tools. Examples can be running or pulling tools for plugs and valves, bailers to collect debris from the wellbore and kick over tools (KOT) to change gas lift valves (GLV) in side pocket mandrels (SPM). All the different tools have different procedures and precautions when used. Each tool has a manual on how to assembly and disassembly the specific one. All the tools in the mechanical BHA are manipulated by force and depth measurements. The operator of the winch control cabin cannot physically see what happens down in the well. They only have the completion drawing and the measured weight and depth from the counter head on the add on drum.

When running braided electric line, the BHA is different. Most of the components have an electric pin which sends signal through the wire and up to surface. Examples of tools that can be run on electric line is perforation guns, logging tools, tractor and stroker. A big difference between mechanical operations and electric operations, is the fact that you can control the tools from surface while in the well. The logging engineer can send signals down to activate the tractor or do specific operations downhole. The BHA also have a casing-collar locator (CCL). This tool will locate every joint where the tubing pieces are connected and other completion equipment in the well. This gives a good accuracy on depth control when performing the operation.

Case well X-1

The well X-1 is a producer in the North Sea. The well was originally drilled late in 1989 as a water and gas injector, but in 2017 it was recompleted to a producer. It mainly produces gas, but also a bit oil. The gas rate is approximately 90,000 standard cubic meters per day, while the oil rate is 31 standard cubic meters per day. The reservoir is sandstone from the Jurassic age, approximately 200 to 145 million years ago.
The maximum inclination of the well is 86.2 degrees at 4713 meters measured depth rotary kelly bushing (MD RKB). Recent measurements from second half of 2021 shows values of H_2S above 50 parts per million. The well also has a medium-high risk of scale in the reservoir.

In Figure 14 below the well survey is shown. More detailed data of the well schematic is shown in Figure 16 at page 30.

Figure 14: Well survey well X-1

It has been conducted 3 intervention jobs on this well during its producing time. In 2017 it was performed a scale dissolver and inhibitor treatment. In 2018 a change of GLV position took place. There were issues reaching SPM 2 by gravity, and the well had to be displaced to gas to reach the pocket. By displacing the well to gas, the fluid column will be lighter due to a lower density of the gas compared to the fluid. The result will be less buoyancy on the bottom hole assembly. At surface the tension readings will be higher than with liquid filled well. Although the well was displaced to gas, the operation had to be performed with electric line with tractor and stroker, because it was still not able to reach the side pocket by gravity.

They also conducted a multifinger caliper run from hold up depth (HUD) at 5140 m to surface. A multifinger caliper is a tool that provides high-resolution measurements of the internal surface of tubing and casing used to evaluate well performance or well integrity (Archerwell, 2022). The caliper has many spring-loaded fingers that moves at any changes in the inner diameter of the tubing. The tool sends live data to surface. You will then obtain a full wellbore profile of the specific well. See Figure 15.

Figure 15: Multifinger caliper (Archerwell, 2022)

The caliper log report did not show any indications of significant scale build-up. Although there was a discrepancy on the diameter of the fingers post calibration. The difference from pre to post calibration was up to 0.240 inches. This also explains the varying measurements throughout the survey. Therefore, the log is of too poor quality to determine small changes due to scale build-ups or corrosion. When analyzing the log, there was an indication of a minor accumulation of scale detected from 265 meters to the tubing hanger at surface. It is uncertain how reliable these data are due to the discrepancy.

In the middle of 2020, a replacement of the down hole safety valve (DHSV) was performed. When running in hole at the first attempt, the pulling tool stopped at 30 meters. The pulling tool was covered in black sticky stuff (BSS) debris. It was performed a couple of runs with broach to open the tubing to the right diameter, and several bailer runs were needed to remove the BSS debris. This shows that the caliper report was reliable. The minor accumulation of scale detected above the DHSV in 2018, probably developed throughout the next two years.

The operation to be performed during my research, in February 2022, was a replacement of a leaking gas lift valve (GLV) and a new multifinger caliper run. The GLV to be replaced was in side pocket mandrel (SPM) 2, the same valve that was changed in 2018. To be able to do the kick over tool (KOT) operation, the DHSV must be pulled as well. This is due to the inner diameter of the safety valve is smaller than the outer diameter of the KOT.

Simulation

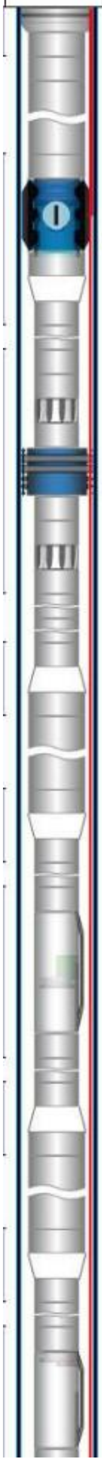
Ahead of the operation, the engineers onshore planned the operation. They planned the tool strings to be used and calculated a simulation. The simulation used water with density of 1.03 specific gravity (SG). The wellhead pressure used was 70 bars, and the weight of the tool string was 1080 pounds (lbs). The friction factor (FF) used is 0.25 both for running in hole (RIH) and pulling out of hole (POOH). Besides a friction of 100 lbs in the grease injection head. According to the simulation, the string should be able to reach a depth of approximately 3040 meters by gravity. From there on, a wireline tractor needs to be used.

The simulation program used while planning, was by a 3rd party company. They used a simulation program that is not available for me. I have used the simulation program IDEX Stimline that is used by my company, Archer. The program used is not set up for tractor due to the service company does not have a tractor available. Therefore, the most realistic data will be down to the hold up depth by gravity. The simulation data from IDEX are also compared to the data from the 3rd party company, to assure similar weights.

At 3040 meters, the completion schematic diagram (CSD) in Figure 16 on page 30 shows slick tubing from 2699 to 4243 meters. And the inclination goes from 67.7 to 76.3 degrees. Therefore, we must look further into the directional survey to find inclination at 3040 meters. The directional survey shows an inclination of 76.24 degrees at 3040 meters. By using Equation 2 we can calculate at which inclination the tools will stop:

$$\alpha = tan^{-1}\left(\frac{1}{0.25}\right) = 76\,°$$

Comparing the calculated value with the value from the simulation, we see a difference of 0.28 degrees. We conclude that the result is realistic and expect the tools to be able to go to 3040 meters by gravity. The calculated value does not take tool weight or well head pressure into account.



Symbol	Extra Info	For	Angle [Deg]	MD Top [RKB] [m]	TVD Top [RKB] [m]	Length [m]	Min ID [inch]	Drift ID [inch]	Max OD [inch]	Description
			0.0	26.550	26.550	0.270		6.305	13.290	7" Tubing hanger SFLL
			0.0	26.820	26.820	2.760	6.184	6.102	7.699	7" 29# Pup w/X-Over - 7" 29#VTHC x 7"26# VTHC
			0.0	29.580	29.580	1.050	6.276	6.151	7.620	7" 26# Pup
			0.0	30.630	30.630	250.484	6.276	6.151	7.620	7" 26# Tubing
			0.2	281.114	281.114	3.060	6.276	6.151	7.620	7" 26# Pup
			0.2	284.174	284.174	1.120	5.750	5.666	8.350	SVLN,KRQ,5.875,7.00-29.00 VAMTOP-HC,B-P,13CR,.BGC
				284.174		*1.410*	*4.000*		*5.720*	*(HSF)WLRSV,OO,5.750 4.00,STD,5K,,AIG*
	Control Line: 1/4" Dual Hydraulic (bumper:)			*284.174*		*0.436*	*4.000*		*5.960*	*(RQS) LOCK MDRL,5.875,13CR,STD,VTR PKG SPEC*
			0.2	285.294	285.294	1.560	6.184	6.102	7.699	7" 29# Pup
			0.2	286.854	286.854	0.810	4.780	4.540	7.680	7" 29# Vam Top x 5 1/2" 20# Vam Top HC
			0.2	287.664	287.664	2.939	4.778	4.653	6.126	5 1/2" 20# Pup
			0.2	290.603	290.603	11.770	4.778	4.653	6.126	5 1/2" 20# Tubing
			0.2	302.373	302.373	2.656	4.778	4.653	6.126	5 1/2" 20# Pup
			0.3	305.029	305.029	0.910	4.700	4.653	7.445	5 1/2" Setting Sub ASV
			0.3	305.939	305.939	0.635	4.695	4.653	8.215	5 1/2" Splice Sub
			0.3	306.574	306.574	0.692	4.716	4.653	8.190	5 1/2" 20# Special Pup
			0.3	307.266	307.266	4.102	4.695	4.653	8.440	5 1/2" ASV Packer
	Control Line: 1/4" Single Hydraulic (bumper:)									
			0.3	311.368	311.368	0.557	4.778	4.653	8.190	5 1/2" 20# Special Pup
			0.3	311.925	311.925	1.201	4.705	4.653	8.375	5 1/2" Optimax WAS-5 Sub
			0.3	313.126	313.126	0.788	4.695	4.653	8.215	5 1/2" Splice Sub
			0.3	313.914	313.914	1.228	4.778	4.653	6.126	5 1/2" 20# Pup
			0.3	315.142	315.142	12.004	4.778	4.653	6.126	5 1/2" 20# Tubing
			0.4	327.146	327.145	12.009	4.778	4.653	6.126	5 1/2" 20# Tubing
			0.4	339.155	339.154	3.280	4.778	4.653	6.126	5 1/2" 20# Pup joint VTHC
			0.5	342.435	342.434	0.721	4.778	4.653	7.699	5 1/2" 20# Vam Top HC x 7" 29# Vam Top
			0.5	343.156	343.155	3.004	6.184	6.059	7.699	7" 29# Pup joint VTHC
			0.5	346.160	346.159	2294.825	6.276	6.151	7.620	7" 26# Tubing VTHC
			63.2	2640.985	1820.236	3.310	6.276	6.151	7.620	7" 26# Pup joint VTHC
			63.4	2644.295	1821.722	0.720	4.780	4.653	7.680	7" 29# Vam Top x 5 1/2" 20# Vam Top HC
			63.5	2645.015	1822.044	3.002	4.778	4.653	6.126	5 1/2" 20# Pup joint VTHC
			63.7	2648.017	1823.380	12.021	4.778	4.653	6.126	5 1/2" 20# Tubing
			64.8	2660.038	1828.613	3.009	4.778	4.653	6.126	5 1/2" 20# Pup
			65.0	2663.047	1829.891	2.780	4.867	4.653	8.062	5 1/2" 20# SBRO-2DGR
				2664.047		*0.543*				*SPD15-1:1.5" Dummy Valve/1.54" OD/13%Cr*
				2664.547		*0.207*				*RK Latch*
			65.2	2665.827	1831.062	3.000	4.778	4.653	6.126	5 1/2" 20# Pup
			65.4	2668.827	1832.315	23.966	4.778	4.653	6.126	5 1/2" 20# Tubing
			67.2	2692.793	1841.940	3.277	4.778	4.653	6.126	5 1/2" 20# Pup joint VTHC
			67.4	2696.070	1843.205	0.720	4.715	4.653	7.070	5 1/2" 20# Vam Top HC x 7" 29# Vam Top
			67.5	2696.790	1843.481	3.006	6.276	6.151	7.620	7" 26# Pup joint VTHC
			67.7	2699.796	1844.629	1543.291	6.276	6.151	7.620	7" 26# Tubing VTHC
			76.3	4243.087	2225.225	3.302	6.276	6.151	7.620	7" 26# Pup joint VTHC
			76.2	4246.389	2226.010	0.720	4.715	4.653	7.680	7" 29# Vam Top x 5 1/2" 20# Vam Top HC
			76.2	4247.109	2226.181	3.006	4.778	4.653	6.126	5 1/2" 20# Pup joint VTHC
			76.2	4250.115	2226.896	12.006	4.778	4.653	6.126	5 1/2" 20# Tubing
			76.4	4262.121	2229.743	3.032	4.778	4.653	6.126	5 1/2" 20# Pup joint VTHC
			76.5	4265.153	2230.454	2.781	4.753	4.653	8.060	5 1/2" Gas lift Mandrel
				4265.153		*0.450*				*1.5" GLV-DuraLift/ 1,54"OD/Inc 718*
				4265.153		*0.207*				*1.5" RK Latch*

Figure 16: Completion schematic diagram (CSD) well X-1 (Courtesy of operator)

Pulling and running weights from simulation

In Table 1, you can see the pulling and running weights from the simulation. From 3000 meters and down to the hold up depth (HUD), the running weight will be the same, due to the use of wireline tractor. You would expect the running weights to change as it goes further down, with more cable in the well. But while running tractor, the wireline winch and the tractor usually runs at the same speed. The logging engineer has constant reading of the head tension of the cable head in the well. If the engineer sees the tension increase too much, the wireline winch operator is asked to run faster to keep a constant tension in the cable head. That is the reason why the running weights is the same from 3000 meters and down to 4265 meters.

Table 1: Simulated pulling and running weights

Measured depth [m]	True vertical depth [m]	True vertical depth [ft]	Pulling weight [lbs]	Running weight [lbs]	Weight with zero friction [lbs]
0	0	0	777	577	677
500	499	1637	1037	787	950
1000	963	3159	1322	735	1204
1500	1290	4232	1352	589	1383
2000	1518	4980	1533	618	1507
2500	1753	5751	1804	694	1636
3000	1929	6329	1745	700	1732
3500	2051	6729	1880	715	1799
4000	2169	7116	2127	715	1864
4265	2227	7306	2095	715	1895

The last column in Table 1, surface weight with zero friction, is calculated by hand, using Equation 3 below.

$$W_{surface} = BF * w * TVD + BF * W_{BHA} - WHP * \frac{\pi}{4} * D^2 \quad (3)$$

Where $W_{surface}$ is the weight at surface in lbs, BF is the buoyancy factor, which is dimensionless, w is the weight of the wireline cable in air in lbs/ft and TVD is the true vertical depth in feet. W_{BHA} is the weight of the toolstring in air in lbs, WHP is the well head pressure in psi and D is the diameter of the wireline cable in inches.
The buoyancy factor is calculated by the equation below

$$BF = \frac{7.85 - \rho}{7.85} = \frac{7.85 - 1.03}{7.85} = 0.87$$

Plotting the weight data against the true vertical depth in ft, we get the graph shown in Figure 17 below. The grey line is the surface weight without friction, which is mostly located between the running in hole and pulling out of hole lines. By calculating these numbers by hand, a quick check of the simulation can be done. This is useful to get an indication of the reliability of the simulated data. As seen on the graph, the grey line is always bigger than the running weights and almost always smaller than the pulling weights. This give us an indication that the simulated data are reliable.

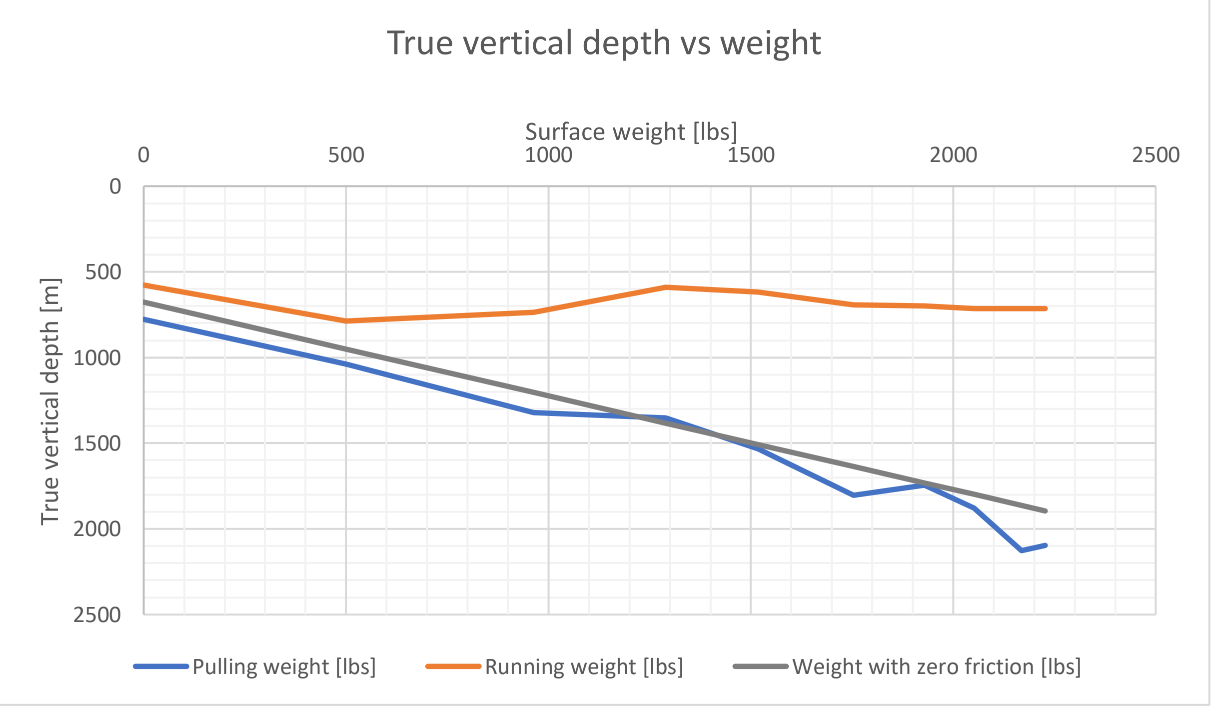


Figure 17: Graph simulated pulling and running weights, and calculated surface weight with zero friction, WHP: 70 bars, FF: 0.25

At surface, where MD=0, we can see from Table 1 at page 31 that the pulling weight (PW) and the running weight (RW) differs with 200 lbs. This is due to the stripper friction, F_{strip}, in the grease injection head. We can show by calculation that the difference between running weights and pulling weights are 2 times the stripper friction. We can calculate the running in hole weights by Equation 4 below

$$RW = BF * W_{BHA} - WHP * \frac{\pi}{4} * D^2 - F_{strip} \tag{4}$$

The pulling out of hole weights are almost the same, but with adding the stripper friction instead of subtracting it. See Equation 5 below

$$PW = BF * W_{BHA} - WHP * \frac{\pi}{4} * D^2 + F_{strip} \tag{5}$$

From Equation 4 and 5 we can find the stripper friction (F_{strip}) at surface, MD = 0 meters. This is done in Equation 6 below

$$F_{strip} = \frac{(PW - RW)}{2} = \frac{(777 - 577)}{2} = 100\ lbs \tag{6}$$

Real data – offshore operation

The operation started in the end of January 2022. The operational tasks to be performed was

- Pull the down hole safety valve
- Pull a leaking gas lift valve (GLV)
- Set a new GLV
- Multifinger caliper run

The first task was to pull the down hole safety valve. As expected from previous operations, it was scale build-ups above the safety valve. The pulling tool stopped at 29 meters rotary kelly bushing (mRKB), which is right below the tubing hanger. The bottom hole assembly was then changed to clear the tubing.

Several runs of broaching and bailing had to be performed. The size of the broach was 6.00''. When the tubing down to the valve was cleared to an inner diameter of 6.00'', all the debris had to be removed by several bailer runs. The debris was black sticky stuff with a measurement of 16,8 VOC ppm. VOC ppm stands for volatile organic compound parts per million. This measurement led to precautions and safety considerations of personal protective equipment

A total of 8 days and 27 runs were performed ahead of the kick over tool operation. Several liters of scale were removed above the safety valve. All these runs were performed mechanically with slickline.

After rigging over from slickline to electric line, the well was bullheaded. The liquid used, was treated sea water with a density of 1.03 sg. This was done due to the high measurements of H_2S last year. The bullheading operation reduces the H_2S levels in the well. The operation was performed by another service company, by using the cement unit onboard.

While running in hole with the kick over tool, from 700 meters, the weight indicator started jumping up and down. This was probably due to a sticky tubing wall. It continued all the way down to where the tools stopped by gravity.

Three runs were performed with the kick over tool. Two attempts to pull the gas lift valve and one attempt to set the new valve. The bottom hole assembly stopped by gravity at different depths each run. See Table 2 below.

Table 2: HUD and WHP with KOT

Attempt	Task	WHP [bar]	HUD [m]
1	Pull GLV	70	1729
2	Pull GLV	83	1689
3	Set GLV	35	2685

On the third attempt, the well head pressure (WHP) is half of the pressure compared to the first attempt. This is due to the gas lift valve has been pulled, and the process operators injected gas in annulus simultaneously as running in hole. This also explains the hold up depth which is 1000 meters deeper than the two first ones.

The real data weights used further, is from the first attempt, where the well head pressure was 70 bars. In Table 3 below you can see the real data from the operation.

Table 3: Real data pulling and running weights

Measured depth [m]	Inclination [°]	Pulling weight [lbs]	Running weight [lbs]
0	0.0	897	697
500	5.2	1370	800
1000	35.0	1750	750
1500	61.6	1900	780
2000	63.0	2300	780
2500	60.4	2650	780
3000	76.1	2600	780
3500	77.2	2700	780
4000	76.0	2980	780
4250	76.9	2940	780

The tools stopped by gravity at 1729 meters. Therefore, the running weights from 1500 to 4250 meters are the same, due to the earlier explanation of constant tension downhole at the cable head. The pulling weights increase at almost every 500 m step, but there is a small decrease from 2500 to 3000 m and from 4000 to 4250 m.

When the run was finished and the tools was rigged out on deck, there was a lot of black sticky stuff in the kick over tool, as shown in Figure 18.

Figure 18: black sticky stuff in the kick over tool

Finding the real coefficient of friction

After comparing the simulated data with the real data, it was obvious that the coefficient of friction used in the simulation was wrong. Every simulated pulling weight value differs from the real data with between 200 and 900 lbs. The red and orange lines in Figure 19 are the real data from the offshore operation. The friction factor used is the same as in the simulation, 0.25 for both pulling weights and running weights. The well head pressure is 70 bars.

By the first looks to the graph, it seems like increasing the friction factor to a higher value for the simulated pulling weight, it will be closer upon the orange line. By reducing the friction factor of the running weights, the grey line will probably be closer to the real running weights.

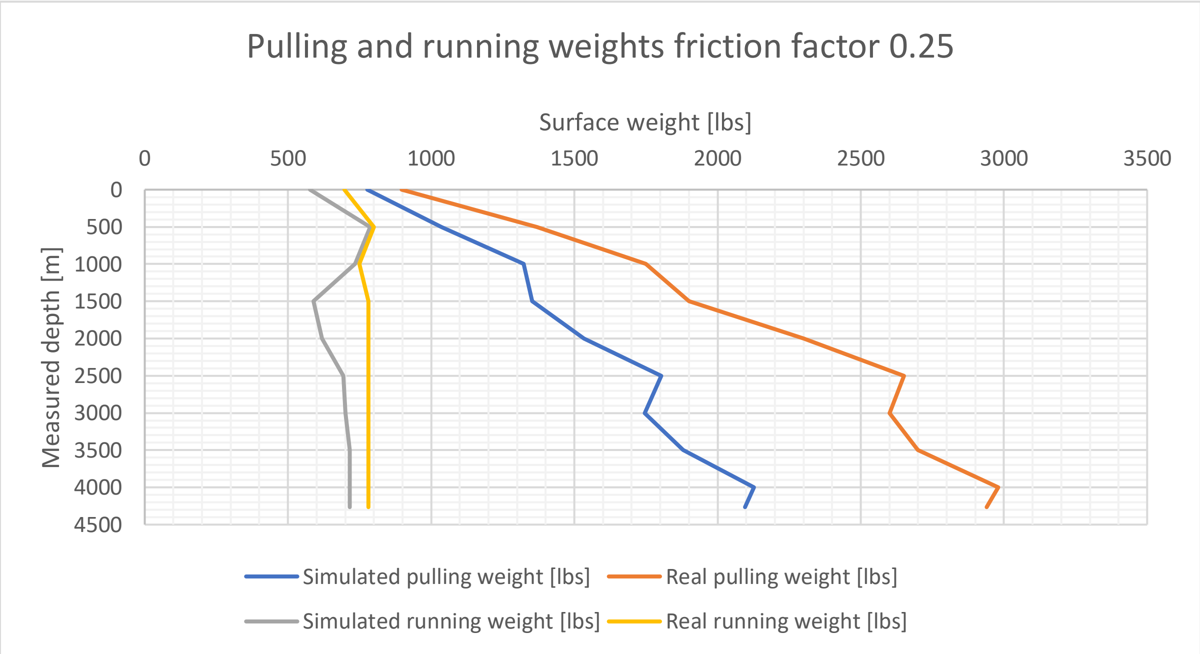


Figure 19: Graph simulated and real data pulling and running weights, WHP: 70 bars, FF: 0.25

By changing the friction factor to 0.55 pulling out of hole (POOH) and 0.17 running in hole (RIH), the graph changes, shown in Figure 20 below. The yellow and grey lines are now closer, as well as the blue and orange line. The hold up depth has also changed to the target depth at 4265 m.

From 2500 m and down to 4250, a friction factor of 0.55 does not fit the real data, as seen on the figure below.

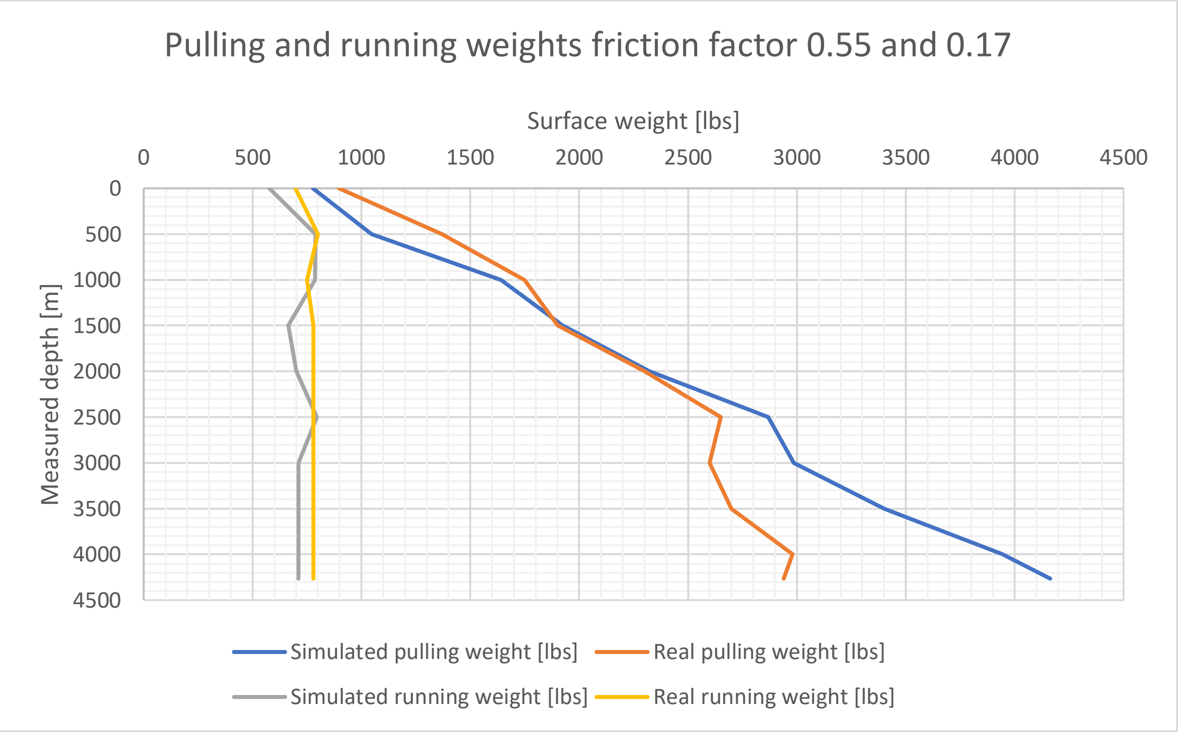


Figure 20: Graph simulated and real data pulling and running weights, WHP: 70bars, FF POOH: 0.55, FF RIH: 0.17

To try to make the simulated pulling and running weights fit the real data, the friction factor is adjusted at every 500 m step. See Figure 21 below. As shown in the figure, the simulated pulling weight are much alike the real pulling weight from 1000 meters and down to the side pocket mandrel. The same goes for the running weights, from 500 m and down. From surface to 1000 meters, the simulated weights and real weights deviates more.

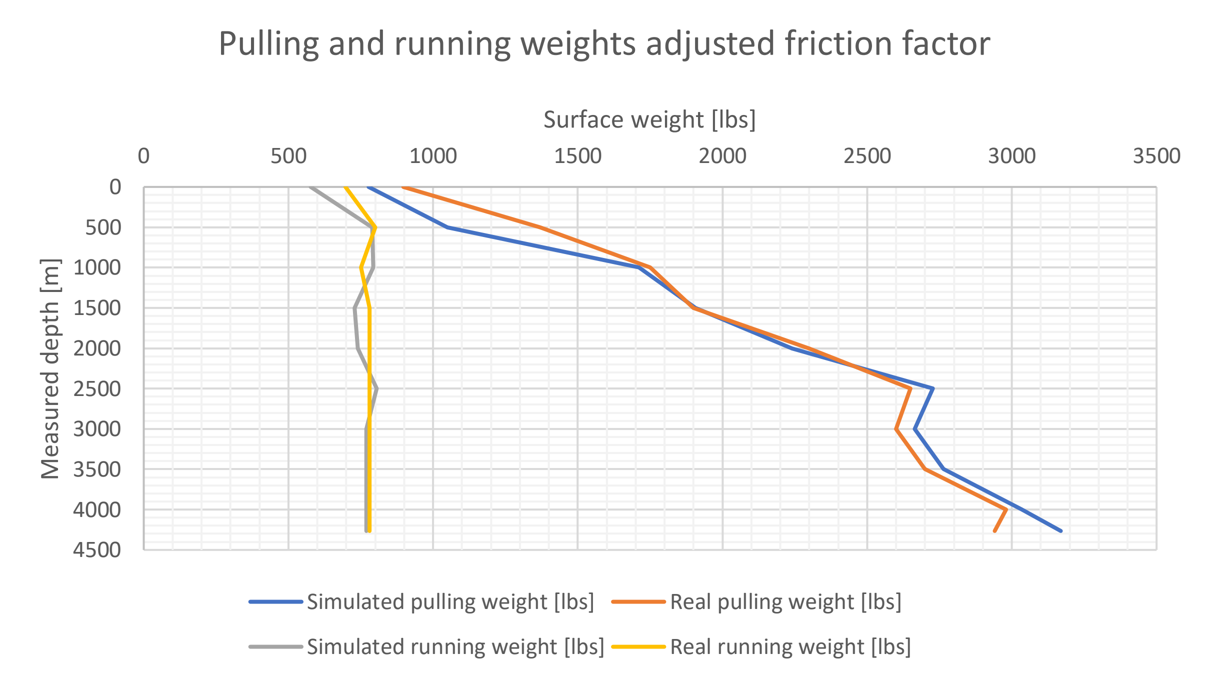


Figure 21: Graph simulated and real pulling and running weights, WHP: 70 bars, FF adjusted see Table 4

The friction coefficients used to find the closest to the real data, are listed in Table 4. For pulling weights, the friction factor ranged from 0.20 to 0.65, and for running weights it ranged from 0.06 to 0.20.

Table 4: Friction factor adjusted simulation program

Depth [m]	FF POOH	FF RIH
0-500	0.55	0.17
500-1000	0.65	0.20
1000-1500	0.50	0.06
1500-2000	0.48	0.06
2000-2500	0.45	0.19
2500-3000	0.40	0.18
3000-3500	0.29	0.10
3500-4000	0.30	0.10
4000-4250	0.20	0.15

From friction coefficients used to find the real coefficient of friction, we can find an average friction coefficient for this case. By summing all the coefficients for pulling out of hole and dividing by the numbers, we get an average coefficient of 0.42. By doing the same for running in hole, we get an average friction of 0.13.

By plotting the adjusted friction factor versus the average friction factor, we get the graph shown in Figure 22 below. The black line is the weight with zero friction calculated earlier. You can see that all the three running weights have a smaller value, and all the three pulling weights have a bigger value. The surface weights are plotted against the true vertical depth (TVD).

Looking at the running weights, the yellow line is the real running weight, and the two grey lines are with different friction factor. The average friction factor of 0.13, does not deviate much from the adjusted factor. Which means in this case, using average friction factor would be accurate enough.

The dark orange line is the real pulling weight. Looking at the two blue lines with different friction factors, the average line deviates more from the real line. The average line only fits the real data from 2100 to 2150 meters TVD. In this case, using the average friction factor is not accurate enough compared to the adjusted factor. But here the average factor would be good enough for planning, since the weights are far away from the breaking strength of the electric wireline cable.
In future planning of operations in wells with scale and black sticky stuff, it would be better to use the average friction, instead of the default coefficient of 0.25.

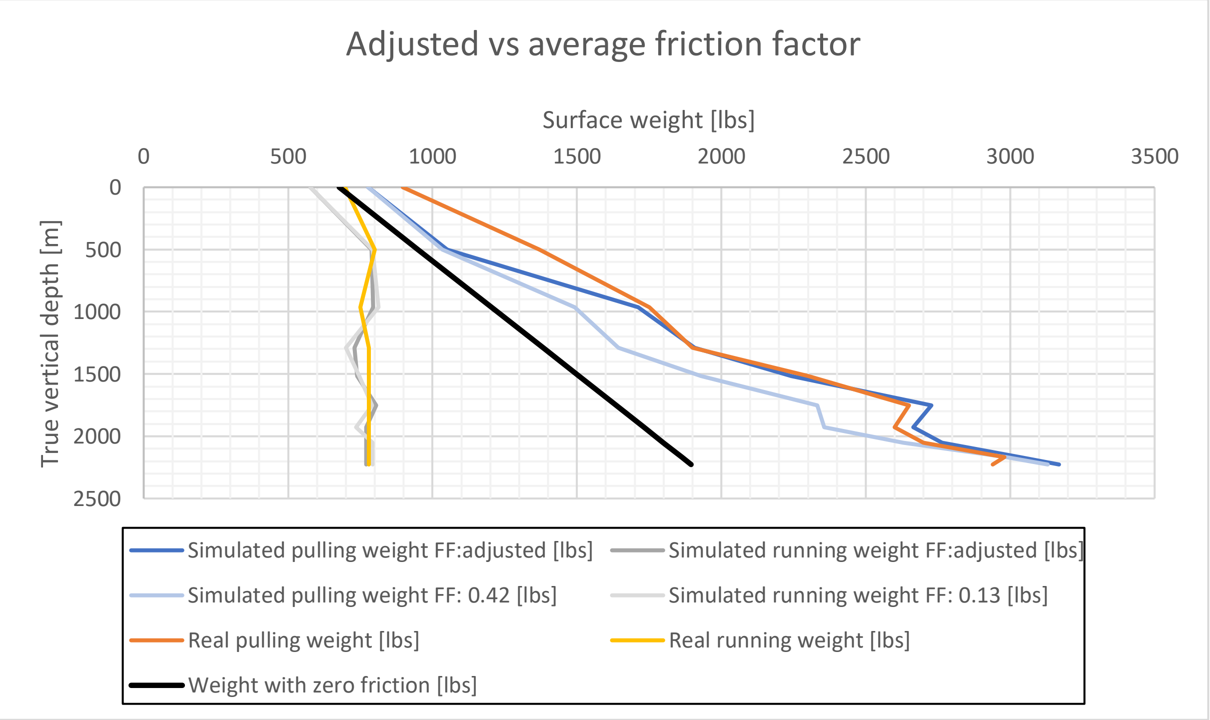


Figure 22: Adjusted vs average friction factor

Conclusion

After comparing the simulated data with the real data from the offshore operation, we found the real coefficient of friction in this well. The average coefficient for pulling out of hole was 0.42, while the average for running in hole was 0.13. The coefficients used for simulation was 0.25 for both pulling out of hole and running in hole.

By looking at the numbers for this case, we can conclude that a default friction coefficient of 0.25 is too low to use when performing operations in wells with black sticky stuff and scale. Based on these findings, a higher value should be preferred in future planning of similar operations where black sticky stuff is a known problem. As shown in Figure 22, the average factor is not that accurate, but better than the factor of 0.25.

Further investigation to be performed to support the findings in this thesis, can be looking into more cases with wells containing black sticky stuff and scale. By doing so, you get more coefficients to compare with and find a more realistic friction coefficient to use in the planning of upcoming operations.

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