UNDERBALANCED COMPLETIONS: A COMPARISON OF TWO WELL INTERVENTION METHODS

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ABSTRACT

During the life of most wells, there comes a time where well remediation efforts encounter pressure. Within this underbalanced condition, two common methods to successfully aid in well intervention are coiled tubing and snubbing (hydraulic workover). There are certain times where either method is a better suit for successful job completion. This paper will compare coiled tubing and snubbing and discuss each service's advantages and applications. In addition, unit specifications, basic calculations and selection criteria will be addressed.

INTRODUCTION

Most of the time whenever well intervention is required, we kill the well (wellhead pressure is 0 psig). The main concern when killing a well is formation damage. An alternative to killing the well is to work on it through live well intervention (wellhead pressure is greater than 0 psig) where the well is underbalanced. The act of snubbing is going to be required any time you have the presence of surface pressure. Snubbing refers to overcoming the resistance to penetration provided by the pressure contained within the wellbore. It also describes a force-balance condition (or the "pipe-light" condition) where an external force is required to prevent the workstring from being forced out of the hole. There are two ways to perform live well intervention which are hydraulic workover and coiled tubing. Going forward, we will discuss the advantages, disadvantages, applications, equipment and unit types for both snubbing and coiled tubing. Then, we will discuss basic calculations, compare snubbing and coiled tubing, and discuss job preparation and execution.

HYDRAULIC WORKOVER

A hydraulic workover "HWO" is a well workover performed using a hydraulic workover (snubbing) unit to run and/or pull tubulars, with or without surface pressure present. These techniques have been in use since the 1920's, with the First Hydraulic Unit developed in 1959. Common misconceptions of for using a snubbing unit are: "Last Ditch" effort on problem/critical wells in emergency situations, for only "live" well remedial services, for only high pressure applications and that it's very expensive. Snubbing units are used in pressures upward of 20,000 psig, tubular sizes from ¾" to 13 5/8", snubbing capacities upwards of 300,000 lbf and lifting capacities upwards of 600,000 lbf. We will now discuss the advantages, disadvantages, applications, equipment and unit types for snubbing units.

Advantages

There are several advantages by using a snubbing unit. Operations are completed while under pressure, so the well does not need to be killed. This aids in reduced costs by eliminating the need for kill fluids and also eliminating the risk of damaging the production formation with the kill fluids. Another benefit is that the well continues to produce, thus the operating company continues to get revenue from production (gas,oil,etc).

Some of the units (rig-assist and mini) have a compact size which aids in reduced rig-up times which helps in reduced overall costs. The compact size also works well on smaller well locations or on platforms where space is limited.

Snubbing units have the ability to rotate the tubulars, giving the ability to drill and mill with bigger bits. This ability to rotate also allows for snubbing units to get deeper into horizontal wells than coiled tubing because they can rotate through wellbore friction pressures.

Depending on the unit, there's a wide variety of tubular sizes that can be utilized ranging from ¾" to 13 5/8". Some wells need help hanging casing or installing larger tubing at higher pressures. Coiled tubing is limited on tubing size and pressure. Since bigger sizes of tubing can be run into the wellbore, this means that higher pump rates can be achieved, which also means larger annular velocities.

Disadvantages

Although there are several advantages to using a snubbing unit, there are some disadvantages. When it comes to cleaning the wellbore, fluid cannot be pumped continuously since the string is broken at every joint (~30 ft). Since there are breaks at every joint, this means that there are longer trip times running in and out of the wellbore.

Snubbing is a very technical operation. A crew must be well trained to operate the equipment. Also, general procedures tend to be more complicated and require more planning. The BOP designs can tend to be complicated to accommodate complex downhole tool configurations.

It can also be dangerous for the operators in the snubbing unit, since they are typically working directly on top of the wellhead. If something were to happen to the integrity of the wellhead, it could become a safety issue. Another safety aspect is that you have to break and make connections through the use of tongs. Gas and additional pressure on surface can potentially be present as well.

Applications

There are several applications for snubbing units. One misconception is that snubbing is only for high pressure applications, but they can also be used for low pressure and zero pressure scenarios as well. We will go through several types of scenarios when snubbing units can be used.

Snubbing units can be used for several well remediation needs. They can be used for fishing or milling inside tubing or casing. They can also be used for cleaning our formation plugs in production tubing liner or casing. Typically scaling issues can arise and some (like barium sulfate) need to be mechanically removed. By removing these obstructions, production can be brought back. HWO's are also used to removed other wellbore restrictions and debris. They can drilling out cement and bridge plugs, wash out frac materials, and remove ice and hydrates from the Christmas tree or tubing. Other remediation needs are gravel packing (sand consolidation), squeeze cementing or plugging back, and plugging and abandoning the wellbore.

Pressure control and well killing can also be accomplished. This can be done by circulating out heavy mud or fluids and thus safely removing the fluid. They can run macaroni tubing to pump nitrogen in wells where depth and pressure are too great for coiled tubing.

Stimulation treatments can also be performed. You can complete wells under pressure. Running and pulling retrievable plugs for selective treatments whether it be chemical, fluid displacement or acidizing. It can also run tubing if needed for a frac string to be stung into a liner.

Drilling applications are another arena for HWO. You can drill if there's a sidetrack in the existing wellbore. Wellbore extension in new hole and slim hole can also be accomplished. Any underbalanced drilling application with higher pressure potential is another avenue for using a snubbing unit.

Equipment Basics

The basic components of snubbing units are: work basket and control panel, hydraulic jack assembly, hydraulics system, pumping equipment and blow out preventers.

The work basket is where the crew operates the snubbing unit. It is the work platform where the control panel is also placed. The control panel is where the operator controls the slips (direction of the pipe), BOPs, hydraulic pressure (snub and lifting forces) and where they monitor wellhead pressure and the weight of the pipe string (on the weight indicator). This is also where the tongs are located to make and break pipe connections. Some units (mostly stand-alone) also have a gin pole which allows the unit to lift pipe without the use of a workover rig or drilling rig.

The hydraulic jack assembly contains hydraulic cylinders, traveling slips, rotary table, guide tubes and stationary slips. The hydraulic cylinders are what dictate the snubbing and lifting capacity of the unit. The more cylinders needed, the slower the unit can trip pipe in and out of the wellbore. Guide tubes are used to minimize pipe buckling and placed in the jack below the travelling slips. The travelling slips (also known as “snubbers”) are what grip the pipe and transmit force to either lift or snub the pipe into the well. The stationary slips are at the base of the jack. They hold the pipe when the travelling slips are moving. Typically there are two sets of stationary slips. One set for when the pipe is travelling up, and another in the opposite position for when pipe is being lowered. The rotary table is found on some snubbing units, predominantly conventional and stand-alone units. It is attached to the travelling assembly and allows for the snubbing unit to rotate pipe.

The hydraulics system is the heart of the snubbing unit. It is what gives power to the slips, gin pole, tongs, rotary table and BOPs. The hydraulic power pack is a system of hydraulic pumps generally powered with a diesel engine. Different valves are used to regulate the hydraulic pressure. The hydraulic hoses are what contain the hydraulic fluid and system pressure. It is crucial that these don’t leak, otherwise you lose pressure to the system and compromise safety.

The circulating system consists of a circulating swivel, kelly hose and pumps. This is how we pump fluid (and nitrogen) through tubing. Pumps have to be designed for the pressure it will encounter and rates needed for application. Fluid considerations need to be addressed as well when choosing a pump. The Kelly hose is he connection between the pump and the circulating swivel. The circulating swivel is what is connected on the pipe (tubing or casing) to pump fluid through.

The BOP stack is the main well control equipment on a snubbing unit. Typically, there are stripper rams and a safety ram. Stripper rams are typically the top two rams on the snubbing stack used to trip pipe under pressure. The safety ram is a typical ram used to change inserts in the stripper rams and act to seal the pipe under pressure. Other blow out preventers that can be used if needed (depending on service conditions) include: blind rams, shear rams, blind/shear, slip and variable bore rams. Some BOP stacks are controlled in the basket (stand-alone units) while in other units they are controlled remotely on the ground (rig-assist and mini units).

Unit Types

There are several types of snubbing units that are used for hydraulic workover operations. They include: conventional, long stroke, stand-alone, rig-assist and mini units. Snubbing units are defined by their nominal pulling capacity, i.e. a unit with a nominal pulling capacity of 170,000 lbf is referred by 170K.

Conventional snubbing units were the first used. They work by using power from the drilling rig for support and to power the BOPs. A problem when using this unit is that it takes a lot of the equipment that the rig uses. It also works in the opposite way a driller typically moves pipe. As the travelling block moves upwards, the pulley/sheave system draws pipe downward. The rotary system cannot be used typically and since there is no guide tube, there can be local buckling on the pipe. These units aren’t used very much anymore.

Long stroke units are self-erecting and have a longer stroke which means they have a faster trip-in rate for tubing. They typically run ~30% faster than jack units with a maximum thirty-six foot stroke. This allows for longer tool strings to be placed within one stroke. The disadvantages are that it doesn't have a guide tube, it handles a smaller BOP configuration and it usually is good for wellhead pressures less than 3000 psi.

Stand-alone hydraulic workover units are self-contained operating systems consisting of modular equipment groups that are easily transported and rigged up. They typically have shorter strokes of 8 feet to 14 feet. These units range from 150K to 600K units. The high capacity units can also snub 300,000 lbf. It can also handle pressures up to 20,000 psig and pipe sizes up to 13 5/8" casing. The disadvantages are that most stand-alone units are relatively low and rigged up on top of the BOP stack thus all thrust forces are placed on the wellhead. Plus, most of the time, personnel work at great heights.

Rig-assist (space-saver) units are smaller in size than other snubbing units due to the BOPs being inside the snubbing unit's frame. The compact design allows for quicker rig-up times thus reducing some operating costs. These units are typically 120K to 170K designs. Their maximum operating pressure is typically 5000 psig with pipe handling up to 5" tubing. They are used in combination with a workover rig.

The mini space-saver unit is an innovative hydraulic rig assist unit designed for a unique market with low pressure snubbing and running completion tubing. Most units have a 50K heavy pipe condition. They require less personnel on location, remotely operated with remote console and operate unit from ground. They are also compact and carried on a bobtail truck. The sole purpose is to run completion string (no rotation or pulling). Max pressure rating is ~2500 psig.

COILED TUBING

Coiled tubing is a continuously-milled tubular product. The basis behind it has been around since the 1940's with the first CT unit being made in 1962. Typical coiled tubing units have tubing sizes ranging from ¾" to 4", tubing lengths upwards of 31,000 ft, common steel yield strengths range from 55kpsi – 120kpsi, maximum working pressures up to 15,000 psi, typical snubbing capacities upwards of 40,000 lbf and typical lifting capacities upwards of 100,000 lbf. Going forward, we will talk about the advantages, disadvantages, applications, equipment and unit types for coiled tubing.

Advantages

As with snubbing, there are several advantages to using coiled tubing. Like snubbing, operations are completed while under pressure, so the well does not need to be killed. This aids in reduced costs by eliminating the need for kill fluids and also eliminating the risk of damaging the production formation with the kill fluids. Another benefit is that the well continues to produce, thus the operating company continues to get revenue from production (gas,oil,etc).

Since coiled tubing is continuous, it is safer since there are no connections to make or break. This also means that circulation can be maintained throughout the entire job. Also, without having connections, there are faster trip times in and out of the wellbore. The absence of connections allows for greater annular clearance and to have well control through continuous well intervention.

With respect to logging, high solid muds can cause wet latches to wash off in drill pipe logging, which causes a loss of signal. With coiled tubing logging, since the electric components are internal, there is no loss of signal. It's also easier to know where in the wellbore the tools are located through the depth indicator.

With respect to snubbing operations, there are faster rig up and rig down times. The units are fairly compact so there is less personnel needed on location.

Disadvantages

As with all equipment, with the good comes the disadvantages as well. The main limiting factor with coiled tubing is the small size of the tubing. The small bore of the coiled tubing causes for very high pressure losses, therefore circulating pressures are higher. This leads to lower pump rates as well. Also, the thin wall thickness reduces the tensile, buckling and collapse strengths. Therefore, snubbing pressures it can withstand are limited. The smaller pipe also means less weight on bit which can cause longer mill/drill times.

Since coiled tubing is constantly moving up and down this leads to excessive wear and premature failure. This is caused by cycling the tubing at high internal pressures over the injector head. Also, the injector head chains tend to alter the roundness of the tube, which further reduces the mechanical strengths of the tube, especially the collapse resistance.

While the unit is mobile and the coiled tubing stays on the reel, the amount of coiled tubing allowed is limited. This is mainly due to its height and weight. Due to DOT restrictions for height and weight, we are limited to the amount of coiled tubing as well.

The biggest disadvantage with coiled tubing is the inability to rotate the pipe. Since coiled tubing is smaller it has less weight. In horizontal wells especially, there’s increased friction between the wellbore and the pipe. Less pipe weight means less force to go against the friction, thus causing the pipe to no longer do further into the wellbore. This is called “lock-up”. If the pipe could rotate, it could help break some of the friction encountered in the wellbore and go farther into deeper laterals.

Applications

There are several different applications for coiled tubing. Currently, we typically think of coiled tubing as a means of drilling out frac sleeves and plugs in horizontal wellbores. Coiled tubing can be used to mill or drill a myriad of wellbore restrictions. This can range from bridge plugs, cement plugs to scale removal with either a bit or scraper. Coiled tubing can also be used to drill wells as well as drilling sidetracks and wellbore extensions.

Due to the coil being a continuous tube, it is great for circulating fluids, such as heavy muds or completions fluids in the wellbore. You can also circulate kill fluids in a well control event. If there is debris, such as sand or plug matter, in the wellbore you can pump it to surface. Another application is jetting. This is where you pump nitrogen to circulate fluid to surface. This reduces the hydrostatic pressure on the formation, thus making it easier to produce. It can also be used for casing-leak tests. This is where a straddle packer can be used to set in an area. Then fluid is pumped into the annulus. If the pressure goes from constant to decreasing rapidly, then you are below the leak. You go up the wellbore, repeating the test, until the pressure remains constant after pumping has stopped.

Cementing operations can also be performed with coiled tubing. Due to its ability to continually circulate and accurate depth measurements, it makes it a prime candidate for spotting or squeezing cement. Coil can also be used to set a cement plug or for plug an abandon scenarios.

Stimulation and chemical treatments are another major category coiled tubing can be applied. You can spot chemicals to a desired depth to pinpoint treatment. Acidizing and stimulation are other applications. In certain environments, hydraulic fracturing is performed with coiled tubing. One advantage of this is being able to pinpoint sand in the wellbore, but you can’t pump at the rate typical fracture treatments are treated. There are two ways CT fracs work. You either pump a high concentration slurry down coil and fluid on the backside, or you pump a lower concentration slurry down the annulus of the coiled tubing.

Permanent coiled tubing installation can also be performed. This can help in wells where they are currently flowing from the production tubing. The velocity string works as a siphon to aid in production. You can also hang cut casing or tubing with sand-cutting tools. Sand control systems (gravel pack) can also be performed.

Due to the versatility of coiled tubing, it can be used to convey a plethora of tools. This includes: fishing tools, impression blocks, junk baskets, overshots and more. It can also be used to set and retrieve plugs. In areas where wireline can't get to depth, you can use E-coil to perform well logging. With E-coil, electric wireline is run inside coiled tubing and can be used for real-time logging. You can also use memory tools as well for some logging suites. Another major application is perforating, especially the very first stage in a horizontal well. This is also known as a "toe prep". This is where the end of the wellbore or "toe" is circulated with completion fluid to clean the well of debris (i.e. drilling mud, etc) and then convey perforating tools for the first set of perforations.

Equipment Basics

The basic components of a coiled tubing unit are: control cabin, power pack, reel, tubing guide arch, injector head and well control equipment.

The control cabin is where coiled tubing operation begins. At the control console, the operator is able to monitor the following: wellhead pressure, hydraulic pressure, injector pressure, inlet pressure, measured depth, speed, weight load, circulating pressure and flow rate (in some units). This is also where the operator is able to control all aspects on the coiled tubing unit including: BOPs, stripper assembly, injector head, hydraulic system, level-wind direction

As with a snubbing unit, the power pack is the heart of the coiled tubing unit. The hydraulic power pack is a system of hydraulic pumps generally powered with a diesel engine or in some cases, an electric engine. Different valves are used to regulate the hydraulic pressure. The hydraulic hoses are what contain the hydraulic fluid and system pressure. It is crucial that these don't leak, otherwise you lose pressure to the system and compromise safety.

The reel system is where the coiled tubing is stored during transport and spooled during operation. The reel has a circulating swivel which allows for continuous pumping. Hydraulics move the reel either forward or backward. Found above the reel near the front of the control cabin is the levelwind assembly. The levelwind is used to control and direct the coiled tubing as it is moved in and out of the well. There is also a set of wheels connected above the levelwind which guide the coiled tubing to the tubing guide arch and injector head. From these calibrated wheels, they are connected to a depth counter which allows the operator to view where the coiled tubing is at within the wellbore.

The injector head is what grips the coiled tubing and exerts force to move the pipe in and out of the wellbore (similar in concept as the slip system with a snubbing unit). It also functions as the support of the coil as it gets deeper into the well. Hydraulic chains are used to move the gripper blocks. The tubing guide arch is located above the injector head. Its main purpose is to support the coiled tubing and to center it as it travels through the injector head.

A key component of the coiled tubing operation is the well control equipment. This includes the BOP stack and the stripper assembly. The BOP stack from the top down includes: blind ram, shear ram, slip ram and pipe ram. They are used whenever issues arise or well control can be compromised. The stripper assembly is installed below the injector head and acts as a pressure tight seal or packoff around the coil as it is run in and out of the well.

Unit Types

There are several different types of coiled tubing units. They include: trailer-mounted, truck-mounted, skid-mounted, micro coil capillary and coil drilling units.

The most common coiled tubing unit is the trailer-mounted design. Trailer-mounted coiled tubing units typically consist of a split rail, drop deck trailer that carries the control cabin, tubing reel, powerpack, injector and BOP's. The rig-up crane is carried on a separate truck or trailer, depending on the lift requirements and rig-up height at location. This configuration is also known as a “one-piece” unit. Smaller one-piece units that have a lift system for the injector head mounted on the skid is known as a “bobtail unit”. Maximum coiled tubing diameter for these units is typically 1 ½”. For areas that have requirements for larger diameter tubing or extremely long string lengths, there are trailer designs that carry nothing but the tubing reel, that can work in conjunction with any trailer mounted unit for offering extended reach coiled tubing work. These units, where the reel is separate, are called “two-piece” units. Other unit configurations include injector handling masts for reduced load on the wellhead. These units are typically over-sized for normal transport, and are used in areas where size and weight are not an issue.

Truck mounted are used in several areas around the world, for several different reasons. Some areas have limited road systems that make it difficult to transport larger trailer mounted units while other areas have smaller work areas at the well-site that do not have room for larger units. Units are available in one or two-truck configurations, dependent on the tubing capacity required and local weight and size limitations. Depending on the design, some truck mounted units come with an injector handling crane mounted to the rear of the deck, whereas the two-truck design has the handling crane mounted on the second truck.

Skid-mounted units are designed for offshore applications. The basic systems of the unit (control cabin, power pack, reel, injector head, etc) are loaded separately and designed for the compact area on an offshore drilling rig.

The micro coil capillary unit was developed to service clients’ needs where deck space, crane limitations or in some cases both were prohibitive in economically servicing wells with traditional capillary and coiled tubing units. This modular unit helps bring a median between traditional coiled tubing and capillary units. The limitation of this unit is that the string lengths are short due to the small drums (reels) used in the well intervention.

Coiled Tubing Drilling (CTD) is beginning to be the drilling method of choice for underbalanced horizontal re-entry drilling in wells with fragile formations. Fast rig-up and shorter trip times make CTD cost effective, and generally results in higher production rates than conventional overbalanced drilling techniques. For specific types of well conditions, coiled tubing drilling can also be cost effective for new well drilling projects. CTD can also be highly cost effective in remote areas where the cost to mobilize a conventional drilling rig can be cost prohibitive.

As there are several coiled tubing units, there are also several designs with regards to the coiled tubing string itself. True-tapered strings are where the wall thickness within the string is continually increasing throughout the string. This design allows more weight on bit, but allows for less available overpull if stuck in the well. Step-tapered designs are where the wall thicknesses in the tube body go from one thickness to another without gradually increasing. This design causes for less string weight. Typically these strings don’t get as far out in the horizontal, but if stuck in the wellbore, there is more overpull. Straight-wall designs mean that the same wall-thickness is observed throughout the coiled tubing string. This design is typical in applications where the work is shallow and low pressure is observed. There are also custom designs where the string is like an hour glass. This string is based on strength to weight ratios where the tube body in the heel of the deviated well is reinforced due to the increased fatigue at that point. Most strings are designed for strength-to-weight ratio while others are designed for specific applications like lateral work (designed for fatigue rather than overpull) while others are designed for utilization versatility. Others are designed for high pressure, low pressure, H2S or acid work.

BASIC CALCULATIONS

There are several types of calculations used in live well intervention. We will go over the basic calculations including pressure-area and volumes. There are several more intense calculations that we will discuss, but not go into extreme detail due to their complexity.

To snub pipe into the well under pressure, the downward force must be greater than the force being exerted on the pipe from the well. To calculate this well pressure force (Fwp, in lbf) we need to have surface pressure (Psurf, in psig) and the tubular outside diameter (OD, in inches).

$$Fwp = Psurf * .7854 * OD^2$$

With regards to hydraulic workovers, at higher pressure applications (typically above 3000 psig) the OD is referenced as the outer diameter of the tube body. This is because at higher operations we strip into the well by ram-to-ram. If operating at a lower pressure application, the outer diameter used is that of the connection body because we are stripping in through the annular preventer.

The next thing we need to calculate is the maximum snubbing force. This helps determine which unit we need to use. To calculate the max snub force (Fmaxsnub, in lbf) we need well pressure force and friction pressure force (Ffric). For hydraulic workover operations, typically the friction pressure is ~30% of Fwp. With regards to coiled tubing operations, Ffric is typically assumed to be ~16% of Fwp.

$$Fmaxsnub = Fwp + Ffric$$

As we begin to place more pipe into the wellbore, the buoyed weight of the string increases. As buoyed weight increases, eventually the buoyed weight equals the well pressure force.

$$Fwp = W$$

This is known as the balance point. To calculate weight (W, in lb) for all scenarios, you need to know the pipe's weight (WT, in lb/ft), the density of the fluid inside the string (MWint, in ppg), the density of the fluid outside the string (MWwell, in ppg), tubular internal diameter (ID, in inches), tubular outer diameter (OD, in inches) and the length of the tubular (L, in feet).

$$W = L * [WT + \{(MWint * ID^2) / 24.5\} - \{(MWwell * OD^2) / 24.5\}]$$

Volumes are also important to know. Internal capacity(Capint) is critical when calculating fluid to be pumped and to know where in the wellbore it is (inside the string, annulus, etc). You need to know the length of the tubular (Ltub) being analyzed in feet and the internal diameter (ID) of the tubular in inches. To calculate (Capint) in barrels (bbls) use the following equation:

$$Capint = (ID^2 / 1029.4) * Ltub$$

Sometimes displacements are used in various applications. For displacements, outside diameter (OD) of the tubular in inches, ID and length are needed.For external displacement (Dispext)in bbls, use the following equation:

$$Dispext = (OD^2 / 1029.4) * Ltub$$

For incremental displacement (Dispinc) use the following equation:

$$Dispinc = \{(OD^2 - ID^2) / 1029.4\} * Ltub$$

Incremental displacement is needed to know in well control situations to know how much fluid is circulated out while pipe is being tripped into the wellbore.

Some of the more complicated calculations that we will discuss (but not fully calculate) are buckling and von mises (tri-axial) stress. After we calculate the required snubbing force, we need to ensure that the pipe selected will not buckle under the current well conditions. All of the pipes mechanical properties and dimensions go into buckling calculations as well as the un-supported length while tripping pipe in the hole. For snubbing applications, this refers to the jack stroke length to be used. For coiled tubing, since the unsupported length is the few inches in the stripper assembly, it is considered, but not as important as in snubbing. They are reflected in column slenderness ratio, radius of gyration and effective slenderness ratio, which determines if the load will be elastic or inelastic ("catastrophic") buckling. Depending on whether the pipe is in a pipe-heavy ("tensile") or pipe-light ("compressive") mode, you have to make sure jack forces don't exceed 70% of the calculated buckling load or 80% of the rated tensile strength of the workstring. One of the most important and complex calculations is the von mises stress. This stress is calculated by analyzing all of the stress that happen to the pipe in the x-axis, y-axis and z-axis. That's why von mises is commonly known as tri-axial stress. The various stresses regarding the three axis' are: axial stress (compression or tension), radial stress (curst and collapse), hoop stress (shear) and torque.

COMPARISON

There are a lot of similar advantages to both coiled tubing and hydraulic workover. You can enter a well under pressure, therefore not having to kill the well and help prevent formation damage. They can both be used for several of the same applications as well. But, there are some applications and advantages each method has over the other.

Hydraulic workover is typically better for higher pressure applications due to its ability to resist buckling better than coiled tubing due to increased wall thickness (weight). Also, in wellbores or applications where larger diameter tubulars are required, snubbing units are a better option. The unit's ability to rotate also works better when trying to intervene in extended reach laterals. Areas where space is limited is ideal for these units, due to their small footprint. Since there is also less equipment and personnel required to operate a snubbing unit, it tends to be a cost saving option over coiled tubing.

Coiled tubing is better suited for applications where smaller diameter tubing or wellbores are encountered. They tend to be able to go in and out of the wellbore quicker than snubbing units, so they are convenient where time is of the essence. Due to its ability to continually circulate, it is ideal for cleanout operations. Since there are no tubing connections and the crew is not on top of the wellhead, operations tend to also be safer.

JOB PREPARATION AND EXECUTION

There are several things that go into job preparation and execution. First thing we need to do in any live well intervention method is to look at the task at hand. To do this we need to have an accurate wellbore diagram showing all tubulars of the wellbore, as well as any wellbore restrictions and a directional survey. Then, wellbore fluids (density and volume), bottomhole temperature, bottomhole pressure, surface pressure and fracture pressure. From here we can begin determining the correct method for the application. We then look at the proper unit, workstring and downhole tools to use for the application. From here we can then design a proper fluid system and pump program.

To ensure that the correct unit, workstring and downhole tools are used, we do pre-job analysis through modeling software. In these models we take a look at the different forces and hydraulics used. The following are some parameters considered in the pre-job modeling: collapse/burst calculations for tubing, critical buckling load, required snubbing force, required lift and snub pressures, von mises stress, hydrostatic pressure, annular velocity, torque, minimum set-down force, maximum pull force, bottomhole pressure, bottomhole temperature, wellbore fluids, completion fluids, CO_2 and H_2S.

Once we have confirmed the unit and workstring to be utilized, we then do a thorough pre-job planning to prepare for the job. Personnel go through extensive employee training and have the proper personal protective equipment. Regular preventative maintenance for the equipment should be performed. Safety meetings should be conducted with regards to location. Location standards should also adhere to the engineering calculations considered. From there, the location layout should be looked at to ensure equipment can fit on location. Then, any final equipment designs such as BOP design, choke manifolds and flowback iron should be addressed. When all of that is set in place, then a running procedure should be drafted to aid in successful job execution.

While getting ready to execute the job, make sure to have a pre-job safety meeting and discuss all overhead loads and safety concerns. Before rigging up and going into the wellbore, ensure that the state of the well hasn't changed (i.e. the pressure isn't significantly higher, etc). If it has changed significantly, re-calculate all stresses to make sure the unit and workstring can safely perform the job. Once the job has begun, the crew has to constantly monitor all pressures (well, circulating, hydraulic systems, etc) and weight loads. If a significant change in wellbore status occurs, the crew must be able to re-act quickly to adjust to the changes. This is why live well intervention can be difficult because it is highly-specialized and technical, and it takes a skilled crew to enable successful job completion.

CONCLUSION

Wells can sometimes encounter pressure. While encountering this pressure you can either kill the well of do a live well intervention. We have discussed several different applications for snubbing and coiled tubing units. By understanding the limitations and basic operations of each option, we can determine a best suit method to remediate the well.

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