EXPANDING APPLICATIONS OF COILED TUBING

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Coiled tubing (CT) technology is continuing to evolve at a rapid pace due to the improvements in CT units, the CT and associated equipment. CT gives operators an alternative method for doing work traditionally reserved for drilling or workover rigs. The scope of this paper is to supply information on several applications currently expanding the use of CT. These include rigless CT completions, CT electric line and drilling with coiled tubing.

RIGLESS COILED TUBING COMPLETION TECHNOLOGY

The availability of large diameter (2 in. and larger) coiled tubing (CT) has made CT a viable alternative to jointed tubulars for initial completions and recompletions. Rigless CT completions can be segregated into several categories: velocity strings, tubing patches, gas lift and electric submersible pump (ESP) installations. With the exception of CT deployed ESP's, the other types of recompletions are generally performed through tubing without workover rigs. This article will summarize the characteristics and application of these types of rigless recompletions.

CT Velocity Strings

Recompleting wells by installing CT as a velocity string to improve flowing tubing hydraulics, thus sustaining production, is the simplest and most common CT recompletion (See Figure 1). The economic benefits are realized by eliminating the requirement for a workover rig and subsequently reducing workover time. CT and associated surface equipment (i.e.-permanent CT hanger and BOP/stripper) design features also may allow the installation to be performed without killing the well. Well candidates for velocity strings are generally gas wells having insufficient gas velocity to lift the liquids from the wellbore due to oversized production tubing.

The size and length of CT needed to sufficiently increase velocity and minimize friction pressure loss is determined using computer models. Friction pressure is a function of the produced fluid velocity, surface pressures and specific gravity of the produced fluids. The limiting factor for velocity strings is the bottom hole pressure (BHP). The increased velocity caused by reduction of the cross sectional area obviously increases friction pressure loss. The formation drawdown must exceed the friction pressure loss plus any system pressure at the surface in order for velocity strings to sustain production. Production can be through the CT x production tubing annulus or through the CT.

CT Velocity String Case History

A marginal well in west Texas with production averaging 100 Mcf/d using a surface intermitter set for two hours of production per day, was determined to be liquid loading. The potential loss of 1.6 Bcf of gas reserves promted several workover options to be evaluated.

Well analysis indicated the flow area should be reduced. The decision to install 1-1/4 in. coiled tubing as a velocity string was influenced by several factors. The cost of the CT velocity string installation was 1/3 the cost of replacing the production tubing with a workover rig. Also, conventional workovers in the field had resulted in a large number of fishing jobs as well as the loss of several wellbores.

The CT velocity string installation consisted of removing the liquid column, cleaning sludge from the perforation interval, jetting the well and hanging 21,500 feet of 1-1/4 in. CT from the surface. The wellhead was removed to allow installation of the CT hanger. A master control valve was utilized for the CT x production tubing annulus. Liquid was jetted from the wellbore as CT was run in the hole. The CT was hung off after completion of the cleanout and flow tests were performed. The well was placed on production and has averaged 390 Mcf/d.

CT Gas Lift Systems

As discussed in the previous section, a velocity string recompletion candidate must have sufficient BHP to over come increased friction pressure resulting from smaller flow areas required to increase velocity. In cases where BHP was not sufficient, gas lift valves have been installed in the CT string reducing the flowing BHP needed to sustain production. CT, in conjunction with gas lift, offers the operator a wide variety of gas lift options. Operators can select injection or fluid operated valves and produce through the CT or the CT x production tubing annulus. Special consideration should be given to gas lift design as correlation selection is critical.

CT gas lift systems are normally run through tubing in existing wells. Wellbores are not required to have existing gas lift mandrels for successful CT gas lift installation. Basically, two types of systems are available: conventional and spoolable. In the conventional systems(See Figure 2), the size and type of gas lift valve and mandrel will be determined by the geometry of the existing wellbore tubulars. Standard side pocket mandrels can be used in 4-1/2 in. and larger production tubing allowing through tubing wireline work such as BHP surveys to be performed after recompletion. Wells with smaller production tubulars will require the use of concentric mandrels or slim hole eccentric mandrels. Slim hole eccentric mandrels normally require the use of small diameter gas lift valves which inherently are not as durable as larger valves. When conventional gas lift equipment is used, mandrels and valves are installed in the CT gas lift string as it is run into the wellbore. A CT segment of appropriate length to locate the gas lift mandrel is run into the wellbore. The CT hanging in the well is secured with slips and then cut between the injector head and BOP. The mandrel is attached to the CT with suitable connectors. An access window is flanged between the injector head and BOP and is often used to facilitate this operation (See Figure 3). This operation is repeated at each gas lift station and the CT gas lift string is deployed to desired depth. Other downhole equipment (i.e.- landing nipples) has been installed in the same manner to allow equipment such as wireline retrievable safety valves to be set in the string after the installation has been completed.

A sealing device is normally installed on the lower end of the CT to isolate the CT x production tubing annulus. This can be accomplished with a variety of devices including mechanical and hydraulic packers, inflatable packers, and seal assemblies. One common method of isolation is to couple a polished bore receptacle (PBR), to a locking mandrel and set it with wireline in an existing nipple profile in the production tubing prior to installing CT. A flapper valve may be attached to the PBR to provide a down-hole pressure barrier while deploying CT recompletion. A locator seal assembly is then coupled to the lower CT end. The complete CT installation is then run into the wellbore until the locator seal assembly opens the flapper valve and is sealingly set in the PBR. A permanent CT surface hanger is set, the CT cut, and the wellhead is nippled up.

Spoolable CT Gas Lift System

This method of recompleting a well is unique because the gas lift valves are installed inside the CT without upsetting the O.D. Valves are mounted in a mandrel which is welded in the CT string during the manufacturing process. CAMCO Products and Services Company's proprietary (patent pending) design allows the CT diameter to be maintained and allows the CT and valve to be bent as it is spooled off of the reel, over the guide arch, and into the well without damaging the valve mechanism (See Figure 4). This approach to coiled tubing gas lift allows the installation to be performed with standard well control equipment due to the elimination of external upsets. Additionally, the CT is not cut during system deployment providing a safer operation which does not require an access window. Peripheral equipment is under development to facilitate one day installation/retrieval of the spoolable gas lift system. A patent pending spoolable surface controlled sub-surface safety valve is also currently under development which will expand the use of the spoolable concept to wells requiring safety valves.

Spoolable Gas Lift Installation Case History

BP Exploration (Alaska), Inc. and Nowcam Services, a division of Camco Products & Services Co., recently recompleted a well by installing the world's first spoolable CT gas lift string at Prudhoe Bay. The 10,076 ft. of 2.375 in. O.D. x 0.156 in. wall CT contained 4 spoolable gas lift valves. The string was hung from the surface inside existing production tubing and sealingly set in a wireline set PBR located in the original completion's 4-1/2 in. tubing tail.

One special requirement was for a subsurface safety valve to be installed in the recompletion. Because a spoolable safety system is not yet available, a standard "D" landing nipple to receive a wireline retrievable safety valve was installed on site at 2000 ft. Other highlights of this job included a specially built hanger designed to facilitate retrieval of the back pressure valve. Several other issues were addressed during the preparation of this completion and will be covered in detail in a later paper. At this time the well is producing 1,100 bpd fluid at a 1.5 MMSCF/day lift gas rate. Actual cost for this CT workover was 40% of estimated cost for a conventional workover.

CT Tubing Patch

The CT tubing patch differs from other types of CT recompletions because it is not hung-off from the surface(See Figure 5). Generally, the upper and lower ends of the CT are sealingly set in the existing production tubing with the upper end usually set below existing sub-surface safety equipment. This type of CT recompletion has been used to improve flowing tubing hydraulics and isolate production tubing-casing communication. Gas lift equipment has also been incorporated in CT tubing patch installations.

One common method of installing CT tubing patches is to couple a locator seal assembly to the lower CT end to seal in a PBR previously set with wireline as has been discussed. A CT segment of appropriate length for the patch is then run into the wellbore. The CT is then cut between the injector head and BOP. The upper sealing/hanging device (i.e.-mechanical/hydraulic packer) with running/release device is attached to the CT with a suitable connector. Again, an access window flanged between injector and BOP is often used to facilitate this operation. The upper assembly is then coupled to the CT remaining on the reel and run in hole until the locator seal assembly is sealingly set in the PBR. The upper sealing/hanging device is set, the release mechanism activated, and the CT used to deploy tubing patch assembly is withdrawn from the well. The well is returned to production without modification of existing wellhead equipment. Additionally, when the upper assembly of CT tubing patch is set below existing sub-surface safety valve, the safety system remains operable.

CT Tubing Patch Case History

The Offshore Gulf of Mexico is subject to government regulations limiting communication between the production tubing and the casing. A CT deployed tubing patch was installed to eliminate the tubing-casing communication in a well which was shut in due to government regulations.

A bottom packoff with a PBR was set on top of a bottom tubing anchor using wireline. The 1-1/4 in. CT unit was rigged up and a PBR stinger assembly was coupled to the end of the CT. After 876 feet of coiled tubing was run in the hole, the coiled tubing was cut to allow installation of the hydraulic disconnect running tool with PBR.

The bottom assembly was stung into the bottom PBR. The seal was tested by pressuring up the casing to 1500 psi. The pressure in the production tubing and casing equalized, indicating a good test. The hydraulic disconnect was released and the remaining CT pulled out of the hole. The upper seal assembly consisted of a wireline pack-off and hold down. The well was shut in prior to deployment of the CT tubing patch. After deployment, the average well production was 1 MMcf gas per day and 34 bbl of liquid per day.

Deployed Electric Submersible Pumps

CT has been used for many workover operations where a drilling or workover rig is either not available or is cost prohibitive. In many areas, the cost or lack of available rigs to service an ESP has been a limiting factor when considering ESP's for artificial lift. CT has been proven to be a feasible method of deploying and retrieving ESP's. The system utilizes standard CT equipment. An access window is required to allow the CT to be coupled to the submersible pump and the power cable to be banded to the CT (See Figure 6).

CT Deployed ESP Case History

A well in southern Oklahoma was initially completed with an ESP deployed on production tubing. The ESP was oversized causing the well to pump-off. The operator agreed to allow installation of a smaller ESP on 1-3/4 in. CT to determine the feasibility of the system.

The oversized ESP was removed with a workover rig. The access window was rigged up on the wellhead to allow the ESP to be assembled and hung off from the bottom of the access window. The power cable lead from the ESP was spliced to the power cable. The CT injector head was rigged to the work window and the end of the CT connected to the top of the ESP assembly.

The CT was run in the hole to ±2000 ft. while the power cable was banded to the CT every 30 ft. The average speed running in hole was 30 ft/min. with a maximum running speed of 40 ft/min.

The CT was hung off on a split bowl slip with a passage for the power cable. The CT was cut to allow the landing assembly to be coupled to the CT and then landed on the wellhead. The well is producing through the 1-3/4 in. x 0.134 in. wall CT at an average liquid production rate of 1400 bbl/day.

COILED TUBING CONVEYED ELECTRIC LINE

Increased drilling of highly deviated and horizontal wells required the development of an economical means of logging and perforating. A concept known as stiff wireline or CT Electric line (E-line) was developed several years ago. The E-line was installed inside the CT enabling the CT to push the logging/perforating tools to the desired location in the wellbore. This allowed wells which were unaccessible using conventional electric line methods to be traversed with downhole logging/perforating tools.

CT E-line provides advantages over other methods of logging/perforating horizontal wellbores. CT E-line advantages include: the ability to run conventional logging/perforating tools, continuous data transmition during entire job, formation stimulation possible with logging/perforating tools in the wellbore, variable logging speed, protection of cable and readily available equipment.

Computer models are available to assist in determining the ability to perform CT E-line operations. The models are used to predict pick-up and slack-off loads and buckling effects on the CT. Information needed for the computer models is the well survey, CT and E-line information, wellbore tubular sizes and fluids.

The installation of the E-line cable inside the CT is accomplished by one of two methods. One method is to hang the CT in an existing well and run the E-line down through the CT. The CT with the internal E-line is spooled onto the CT reel. A newer method for E-line installation is to insert the E-line during the CT manufacturing process. The most common CT size used is 1-1/4 in. O.D. with other sizes available. The E-line range from single conductor to seven conductor. The operation performed will dictate the size of both the cable and the CT required.

The CT reel is adapted to allow the E-line to exit the CT and still allow fluids to be pumped during CT E-line operations. Standard collector rings are used to connect the signals from the reel to the E-line control house.

At the present time, there have been over 300 CT conveyed E-line jobs performed. The maximum horizonal distance traveled is in excess of 3,500 feet with a maximum deviation angle in excess of 100 degrees. Jobs performed include cased hole logging, open hole logging, production logging and perforating.

CT Conveyed Electric Line Case History

A well in the Gulf of Mexico required a pulsed-neutron, gamma ray and casing collar locator to determine the plug back potential. The well was required to flow during the logging process. However, the well tended to load up with fluid, making CT E-line a candidate due to the ability to jet with nitrogen during the logging process.

The CT E-line reel was run in the hole to plug-back TD of 12,210 ft. Nitrogen was used to keep the well flowing while logging at $\pm$25 ft/min. After the desired interval was logged, the logs were evaluated to determine where to set the bridge plug.

CT DRILLING

One of the newest applications using CT is drilling directional wellbores. In the past, CT milling has been used primarily for removing scale, cement and hard sand bridges. CT has also been used to deepen vertical holes. Recently, CT has been used to re-enter existing wellbores and drill a horizontal section.

Drilling a horizontal section with CT offers the operator several advantages over conventional horizontal drilling operations. The well can be drilled without killing the well reducing formation damage caused by drilling fluids. Smaller hole diameters reduce the size of mud pumps and associated surface handling equipment. Fast trip times reduce the total time at the well site.

Drilling with CT uses conventional steering tool technology (Electric line or MWD). The CT drilling bottom hole assembly (BHA) includes a mill, motor, steering tool, non magnetic collars and an orienting tool. The orienting tool is necessary due to the inability of the CT to rotate the bit face to the proper directional orientation.

CT drilling is still in its infancy. As with any new technology, there are problems to overcome. The two major problems associated with drilling with CT are proper orientation and controlling the weight on bit. Until these problems are eliminated, the potential economic benefit to drilling with CT will not be realized.

CT Drilling Case History

A vertical well in the Austin Chalk was selected as a candidate to drill a horizontal section using CT. The well was originally completed with 4-1/2 in. casing to 7240 ft. A rig was used to set a whipstock, mill a window in the casing and drill 55 ft. prior to CT drilling operations.

The CT drill string consisted of 10,050 ft. of 2 in. CT with 5/16 in. single conductor wire inside the CT. The bottom hole assembly (BHA) consisted of bit, mud motor, bent sub, back pressure valve, adjustable make-up sub, monel drill collar, orienting sub and a CT wireline connector. BHA length was in excess of 60 ft.

A total footage of 1652 ft. with a horizontal section of 1,458 ft. was drilled. However, the orientation tool proved to be a problem during the duration of the job. Almost 40% of the total cost was attributed to extended orienting and surveying due to tool malfunctions, fishing and waiting on tool repairs.

Summary

Advances in CT and related technologies have made CT a cost effective and functional alternative for both initial or remedial completions. Technology has been successfully applied to incorporate artificial lift in CT recompletions. The flexibility of rigless CT completions available in sizes up to 3-1/2 in. O.D. allow a wide variety of completion and workover operations to be performed without rigs.

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INCREASES VELOCITY BY
REDUCING FLOW AREA

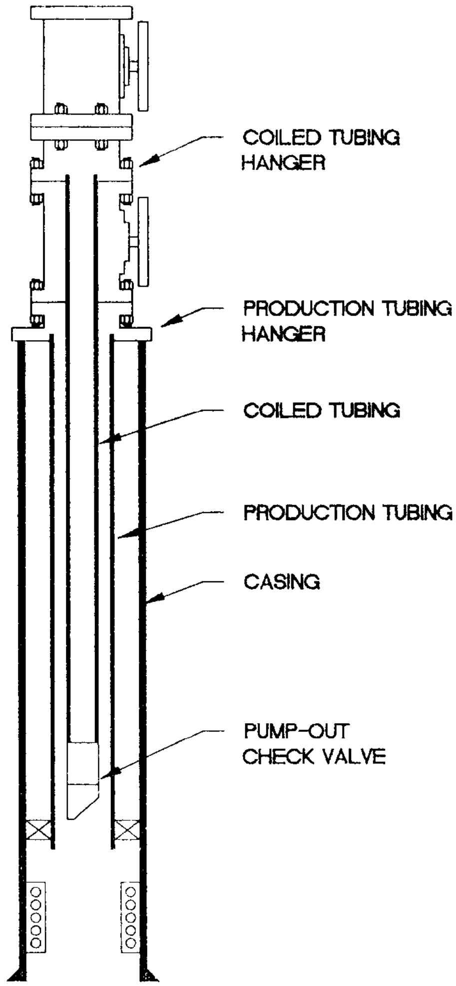

Figure 1 - Coiled tubing velocity string

INCREASES DRAWDOWN BY
REDUCING FLOWING GRADIENT

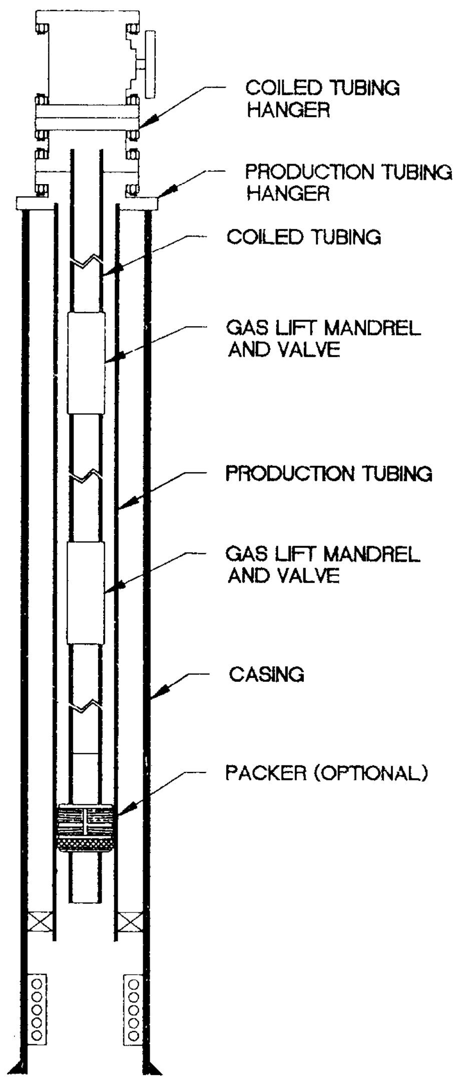

Figure 2 - Coiled tubing gas lift system

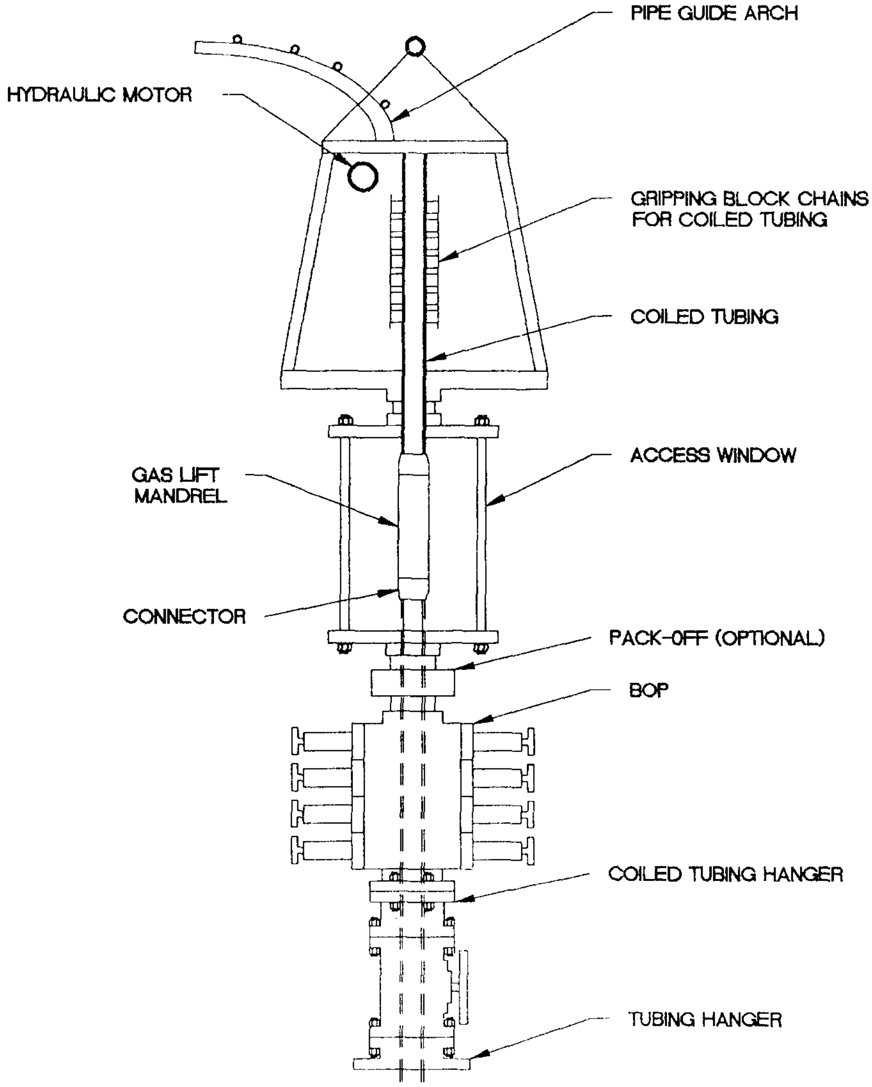

Figure 3 - Window installed gas lift valve

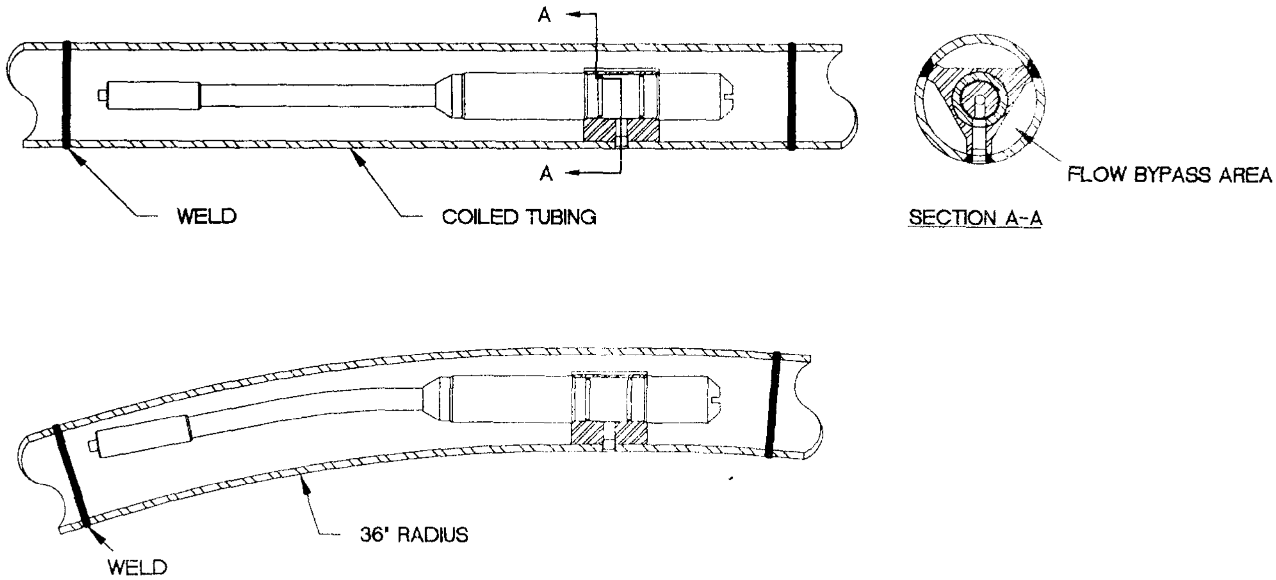

Figure 4 - Spoolable gas lift valve

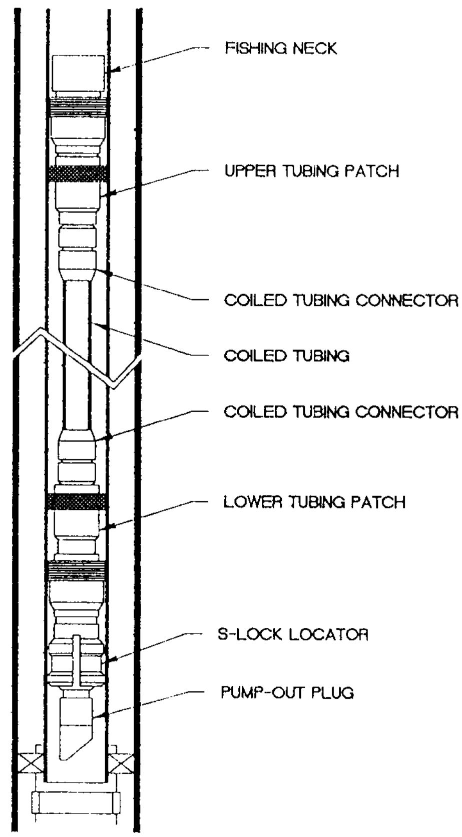

Figure 5 - Coiled tubing conveyed tubing patch

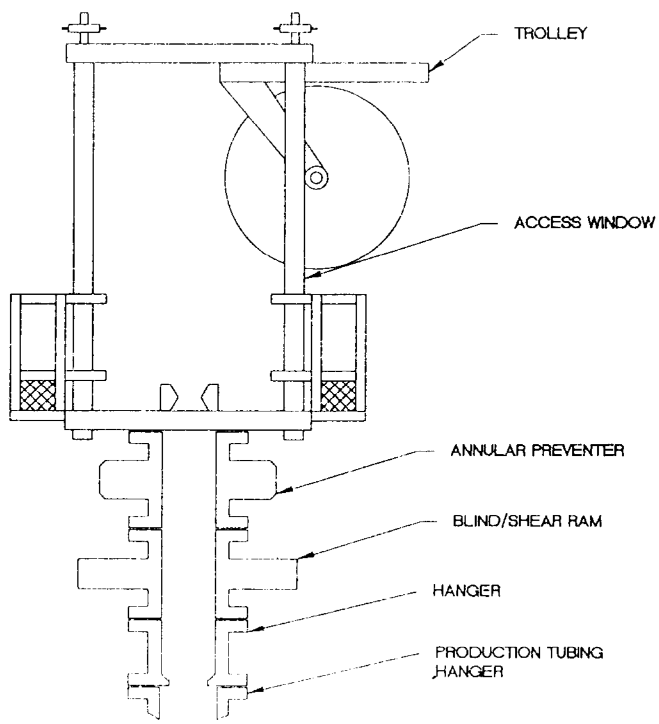

Figure 6 - Coiled tubing/ESP rig up