WORKOVER AND STIMULATION OF WATER INJECTION WELLS USING CONTINUOUS COIL TUBING

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ABSTRACT

Continuous coil tubing has become a viable alternative to the conventional workover method of injection well cleanout. With the increase in the wellhead price of oil, a greater emphasis is placed on the efficiency of in-place waterfloods. When an injection well within a flood becomes plugged, the method by which the well is monitored should indicate if there is a problem. Based on that indication and all available relevant data, a decision can be made as to the kind of problem which has developed and likely methods of correcting that problem. The use of coil tubing in many cleanout procedures is a cost- and time-saving method. The circulation method is accomplished without the need of moving or disconnecting any part of the injection string. The wells do not have to be backflowed and stimulation jobs can be done with minimum exposure of the injection string to the corrosive effects of acid. A treatment technique can be designed to correct or counteract problems within the injection profile on a point-to-point basis.

INTRODUCTION

The treatment techniques developed through the use of coil tubing since its introduction in the mid 1960's has produced an effective and economical method of cleaning injection wells. The circulation method is accomplished without the need of moving or disconnecting any part of the injection string. As a result of this process, the injection well does not have to be flowed back prior to treatment and the injection string and packer do not have to be redressed after a conventional cleanout.

The advantages of using coil tubing to clean and stimulate the well would be negated if the injection string has failed prior to the cleanout. At that point both the rework and cleanout could be done together. With the advent of "lined tubing", however, the injection strings are now lasting through several intervals, and coil tubing could be used to enhance injectivity. Build-ups in the well bore such as iron sulfides, carbonates, and insoluble precipitates can usually be circulated out with coil tubing. After the removal of these types of build-ups, a properly engineered stimulation treatment can then be performed through the coil tubing which will eliminate exposing the injection string to the corrosive effects of acid.

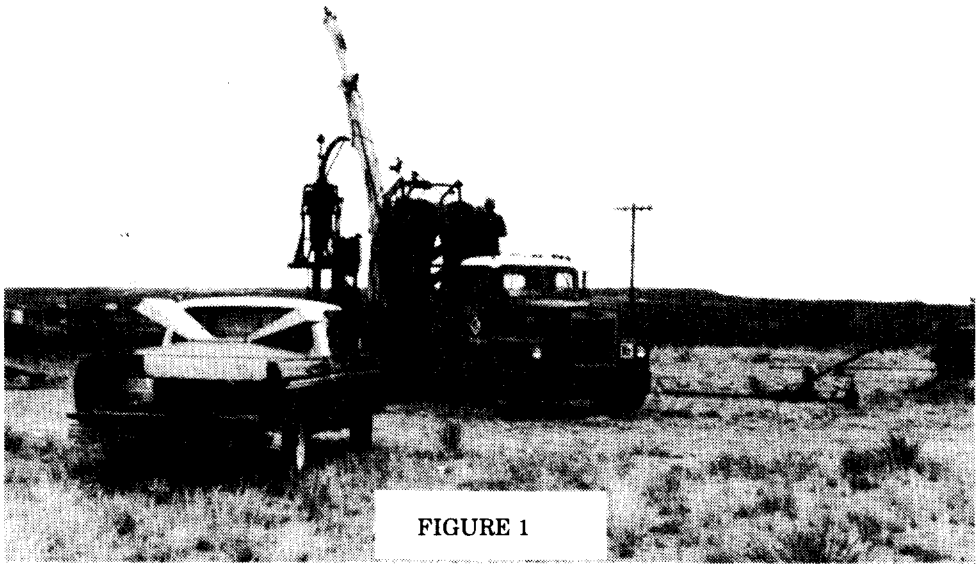

FIGURE 1

CONTINUOUS COIL TUBING

The tubing unit today is a highly mobile unit which is designed to be used as a work string or as a single-point gas lift system at depths up to 15,500 ft. The tubing is usually 1-inch O.D. and is made out of a low-carbon steel which possesses high yield strength. The steel tubing is carried on a hydraulically operated reel. The reel works in coordination with the hydraulically driven injector head which is rigged up on top of the wellhead. The injector head is capable of moving tubing in and out of the hole with an exerted force of up to 12,000 lbs. The head uses two endless chains. The tubing is gripped between these two chains in a series of contoured sheaths which centers the tubing in the chain mechanism. Force is then applied horizontally against the tubing by the chains while they are hydraulically turned in the desired direction.

As the tubing is run in the hole it is straightened in the adjustable grooved sheaths. A Cavins-mechanical counter located between the tubing reel and injector head automatically records the amount of tubing in the hole. Under the injector head is a well control stack with hydraulically operated lubricator and blow out preventor. The coil tubing unit is designed to work under wellhead pressures of up to 5,000 psi and the tubing can be stripped in and out of the well when worked within the pressure limitations.

COIL TUBING	3/4" Tubing Specifications	1" Tubing Specifications		1-1/4" Tubing Specifications
Outside Diameter	0.750"	1.000"	1.000"	1.250"
Inside Diameter	.636"	0.866"	0.832"	1.082"
Wall Thickness	0.057"	0.067"	.084"	.084"
Weight (lbs/1000 ft)	421	667	814	1039
Capacity (bbls/1000 ft)	0.393	.728	.673	1.137
Average Yield	65,000 psi	65,000 psi	65,000 psi	65,000 psi
Average Tensile	79,000 psi	79,000 psi	79,000 psi	79,000 psi
Theoretical Burst	12,959 psi	11,350 psi	14,490 psi	11,383 psi

WELL CONDITIONS

Well conditions will, of course, vary with depth and coil tubing units have application in most wells regardless of depth. The injection well application, however, falls into a relatively uniform set of well conditions. The well will be less than 8,000 ft. with a fracture gradient of .6 to .7 psi per foot of depth. The injection string will usually have a protective covering and the packer will be set approximately 50 ft. above the highest perforation or open hole interval. A great deal of work has been done to identify and achieve the desired injection profile. Over several years, the accumulation of several problems have caused a decrease in the volume of water injected and appreciable increases in wellhead pressures.

Higher pressures and lower injection rates generally are associated with several phenomenons. Higher pressures will result as the cumulative input increases. The pressure increase is the result of the force necessary to push the residual oil. This increase in pressure, however, should be slow and easily plotted on a graph as a safety check[1]. A sharp increase in pressure with accompanying decrease in injection rate is usually the result of low permeability caused by the build-up of iron sulfides, carbonates or insoluble precipitates. This low permeability may be seen in the form of fill which accumulates in the hole. The formation itself may be plugged due to build-up of insolubles and carbonates which continually decreases permeability in the vicinity of the well bore. The injection system seems to be the primary source of this type of plugging. A third problem is the build-up of iron sulfides which form bridges and accumulate in perforations to form plugs.

When these types of problems arise, the desired injection profile is probably not being achieved. The effectiveness of the water flood becomes less efficient. With low oil prices, most water floods have been "poor boy" operations. In most cases the water flood systems have been neglected for several years. As the price of oil rises, an efficient flood becomes more and more advantageous.

MAKING THE DECISION TO CLEANOUT AN INJECTION WELL

As the wellhead pressures increase and injection volumes decrease, unfavorable conditions become more apparent. Pressures above the normal sweep force indicate that restrictions are reducing the flood efficiency by making part of the desired injection profile inaccessible. The increased surface pressure adds to the possibility of fracturing the formation and diverting the injection water to an unproductive area and possibly out of zone.

If the water flood is closely watched, injection profiles are routinely run to check where the injected water is going. In this kind of system, problem areas in the profile are quickly recognized. Most wells, however, are monitored by surface pressure and input volumes alone. In this kind of system, profiles are usually run after an obvious problem (like a hole in the tubing or low input) have called attention to a particular well. If the injection system as a whole has lost input volume a "sinker bar" is usually used to see which injection well in the flood has fill in the hole. At this point in time, profiles may be used on the unobstructed wells to determine if the injection well has plugged perforation or if the formation has lower permeability making "low flow" zones within the formation.

These "low flow" zones may or may not be important to the efficiency of the injection well relative to their size and location within the profile. The correlation of perforations with relative bench lithology within the formation and continuity of these benches throughout the flood is the measure of sweep efficiency. In figure 2, the "low flow" area is probably a major problem because of its size and consolidated location within the formation. In figure 3, the "low flow" zones may not be playing a significant role in the overall efficiency of the well because the two areas are small and divided with a high flow channel between them. The evaluation of previous logs which have been run on the same wells will indicate if there was injection into these "low flow" areas earlier in the flood.

The decision to cleanout an injection well is a simple matter if fill has accumulated to the point that injectivity has stopped. The decision to cleanout wells with "low flow" zones, however, can be a complex decision. If the zones were originally taking fluid, then there must be a restriction which has accumulated at or within the formation itself. The accumulation of iron-sulfide, carbonates and insoluble precipitates is usually the reason for the restricted permeability. Poor water quality is usually the culprit. Pro-longed injection of these types of particles can only be counteracted with unconventional methods of cleanout.

The "Hall Technique" is a method of analyzing and evaluating changes in injection well capacities by the use of a graph. Hall shows that the slope of the cumulative wellhead pressures multiplied by the time interval plotted against cumulative barrels injected is proportional to well capacity. If the capacity is constant the plot should be a straight line[2]. If the normal slope of the line plotted increases over a period of time, it is an indication of some form of plugging or formation damage. A subsequent decrease in the slope shows some kind of improvement in the well bore capacities (Figures 4 and 5).

All of these tools are helpful in determining the kind of problems which have developed in the injection well. After the problem is found a method can then be devised to solve or counteract the problem. Because the coil tubing can be reciprocated freely within the normal set-up of injection string, a variety of techniques and treatments can be used on a point to point basis with the problem.

SETTING UP AND PERFORMING AN INJECTION WELL CLEANOUT

The preparation prior to a coil tubing job is relatively simple. Wells should not be shut-in or flowed back for long periods prior to treatment. Shortly before the cleanout, a "tee" should be installed on top of the wellhead. If the installation of the tee hampers injection, then injection connections should be disconnected until after the cleanout. The tee will serve as a connection for both a secured flowline and as a connection for the injector head.

The flowline should be of steel line which is well secured for safety. A control valve should be in the flowline and close to the wellhead so that the return flow can be controlled. The master valve will be inoperative during the treatment because the coil tubing will be injected through it during the cleanout or jet lifting a well. Great care should be exercised while running in the hole with the coil tubing. Unknown obstructions could cause the tubing to kink and break if the tubing is inserted too quickly. Fluid is usually pumped through the tubing while it is injected to prevent plugging the wash tool and in some cases the 1" tubing. After reaching the packer, preparation should be made to use the desired technique which was pre-designed to correct the well problem (Figure 6).

A general recommended procedure for cleaning out fill and flushing out fines from the immediate well bore would go as follows (Figure 7).

1. Rig up continuous coil tubing unit with special jetting tool and run to top of perforations while slowly pumping water through coil tubing to prevent plugging.
2. Jet wash with water to total depth. Circulate to clean up. If hard fill is encountered, spot approximately 1 BBL of acid on fill and close in flow line. Let soak for a few minutes before opening flow line and continuing washing.
3. After well is free of fill, spot remainder of acid or acid/xylene mix to end of coil tubing and close in flow line. Jet wash with the selected volume of treating fluid while reciprocating the end of the coil tubing back and forth across the perforations. If there are no "flow" zones in the well, particular attention can be directed at these areas.
4. Let acid soak for 30 minutes. If well will not flow on its own, run coil tubing to bottom of the hole and jet lift with 25,000 SCF of nitrogen at the rate of 600 SCF/min. This will ensure clean up of insoluble particles.
5. Pull coil tubing and return well to injection status.

Many variations can be made from this general procedure. The amount of acid or acid/xylene mix needed to clean a particular well should be determined on a well to well basis. The longer wells have been on injection without being cleaned out, the more likely it is that the fill in them has hardened to a point where coil tubing and its jetting action will not be able to penetrate the fill. If the wells have to be cleaned conventionally, then a regular cleaning with coil tubing from that point forward can be routinely done.

SPECIAL TOOLS FOR SPECIFIC APPLICATIONS

The variety of wash tools are as diverse as the number of applications. The use of a specific tool design is dictated by how powerful a jet the tool will need and in what shape or direction the jets are designed to wash. Since approximately 30 gallons per minute is the maximum rate for fluid pumped through 1" coil tubing the size and number of holes in the wash tool will control the nozzle force. In some applications the use of a "knuckle joint" may be advantageous. The knuckle joint with a two foot stinger between it and the wash tool gives flexibility to the end of the coil tubing while working in open hole.

The flexibility is helpful because the coil tubing has a natural arc and tends to follow one side of the hole[3]. In open hole situations the tubing can be hindered by deformities and washouts in the walls of open hole wells. A variety of centralizers have also been developed for coil tubing. The use of centralizers, however, has diminished. The biggest innovation in recent years has been the use of a 1-3/4" Dyna-Drill on the end of 1" coil tubing to do jobs which before were too tough for a jet tool. A good example of this process is the drilling out of green cement after a squeeze job on a slim hole completion. This process, however, is too tough on internally coated tubing and is not recommended for use under those conditions.

The use of special tools can greatly add to the effectiveness of coil tubing. Great care should be used, however, in the selection of one or a combination of these tools. The condition of each well should be evaluated prior to their use and any known restrictions should be noted.

CONCLUSION

The use of coil tubing has proven to be a viable alternative to conventional methods of injection well cleanouts. Regular cleaning of injection wells can eliminate most of the common problems which occur during the life of the flood. The development of restrictions in the well bore, perforations or along the face of the formation seriously detract from the flood's efficiency[4]. The development of these problems should be discernable from the method used to monitor the injectivity. To eliminate problems associated with pulling tubing for a conventional cleanout, coil tubing should be considered. Some major advantages to using coil tubing are that the wells remain intact, blowing down the well is unnecessary, and in most cases the cleanouts only take one day. The longer wells have been on injection without being cleaned out, the more likely it is that if fill has accumulated a portion of the fill has solidified. Penetration of this solidified fill may or may not be possible. If conventional cleanout is necessary, a regular cleaning with coil tubing from that point on can be routinely done.

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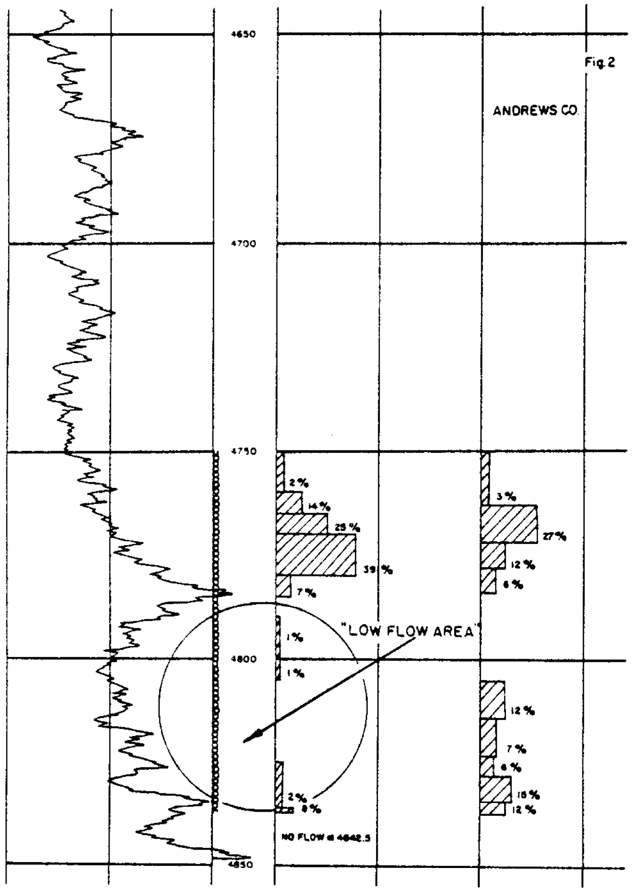


FIGURE 2

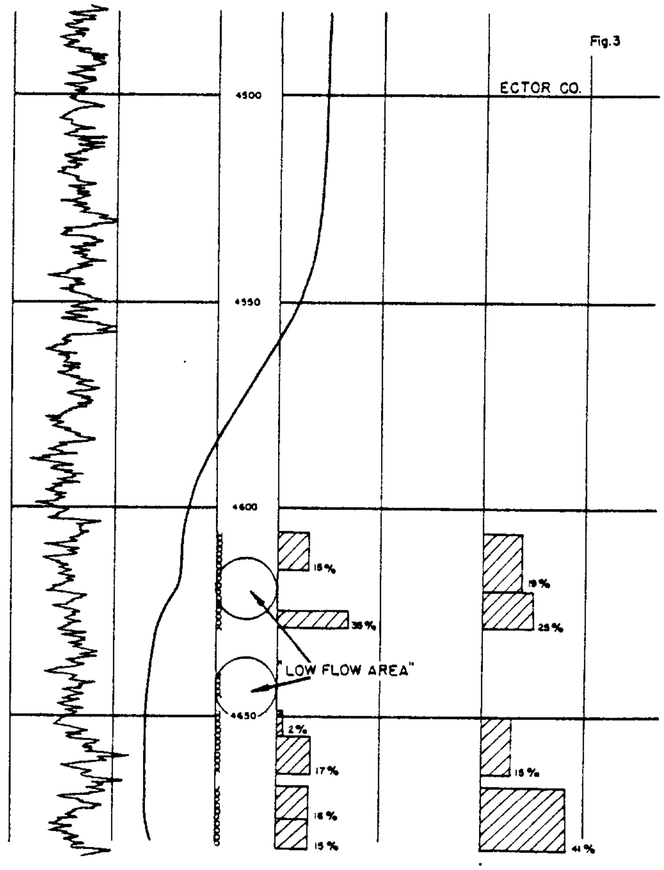
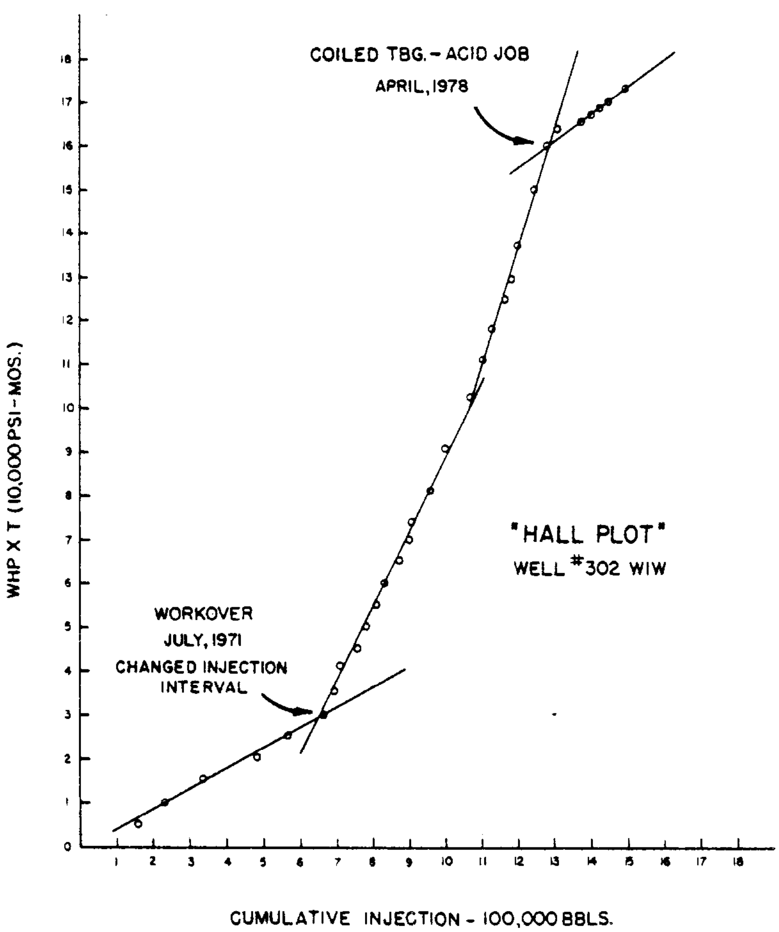


FIGURE 3



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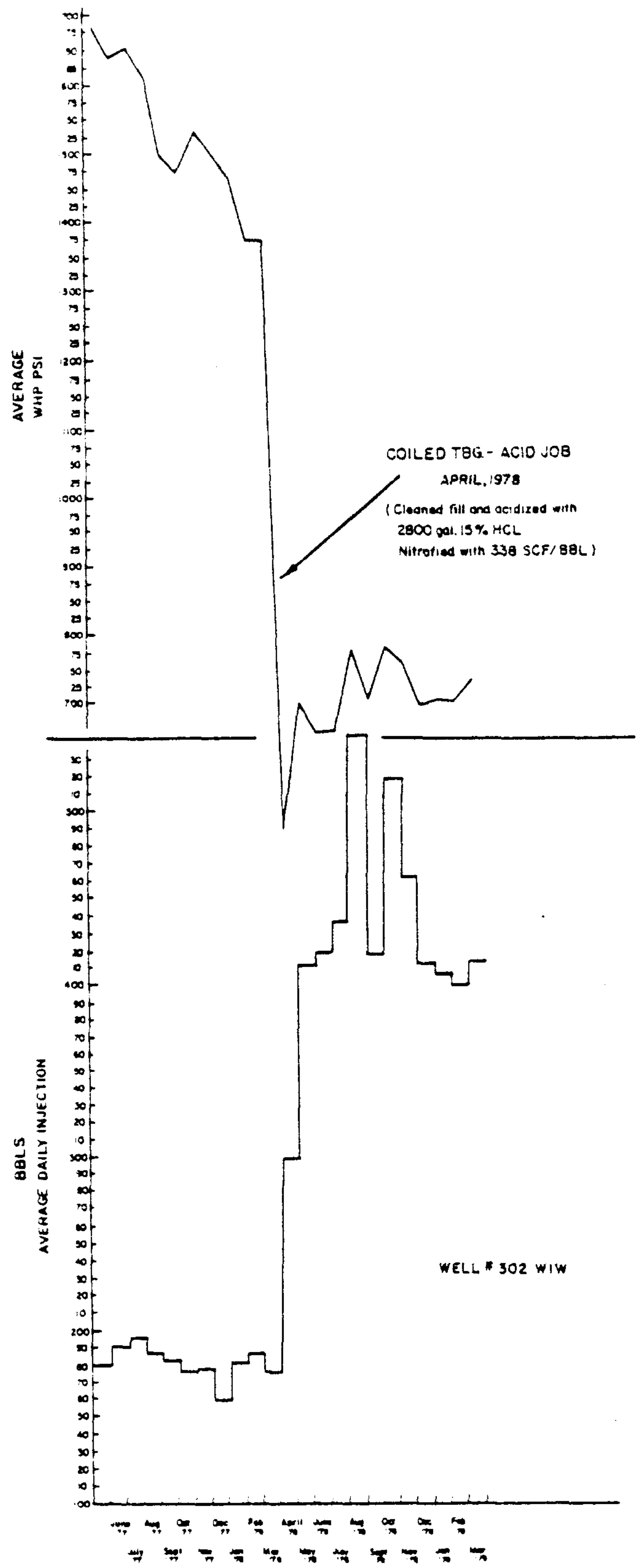
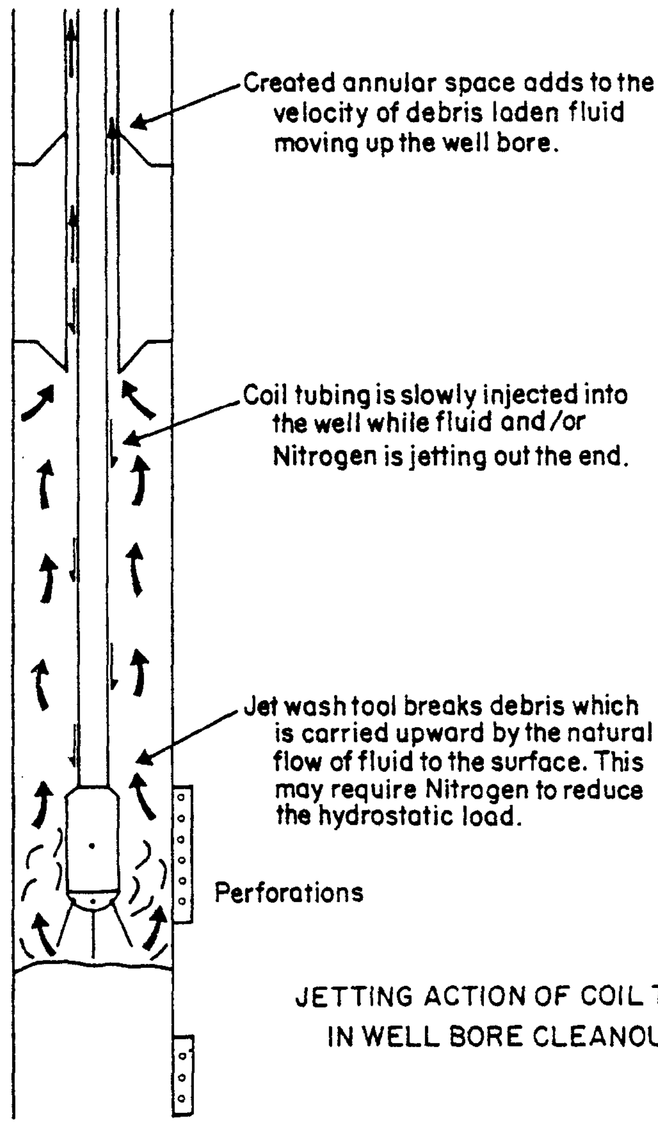


FIGURE 5



JETTING ACTION OF COIL TOOL IN WELL BORE CLEANOUT

FIGURE 6

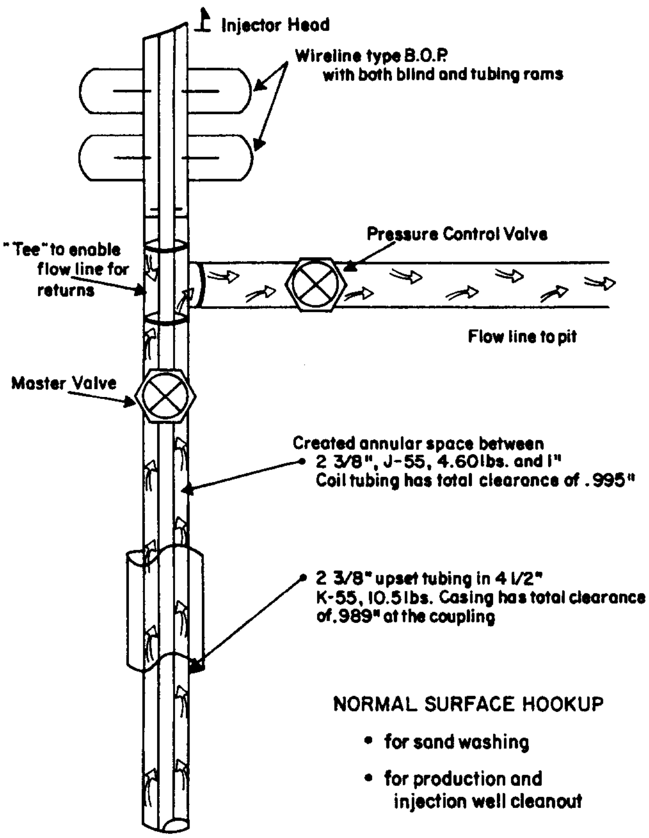


FIGURE 7

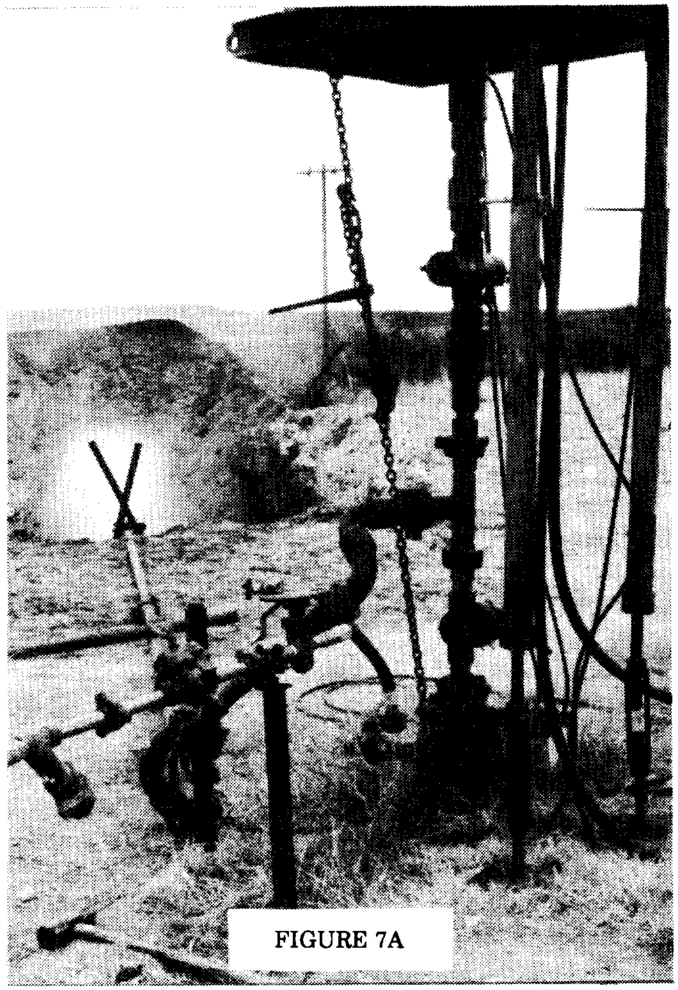


FIGURE 7A