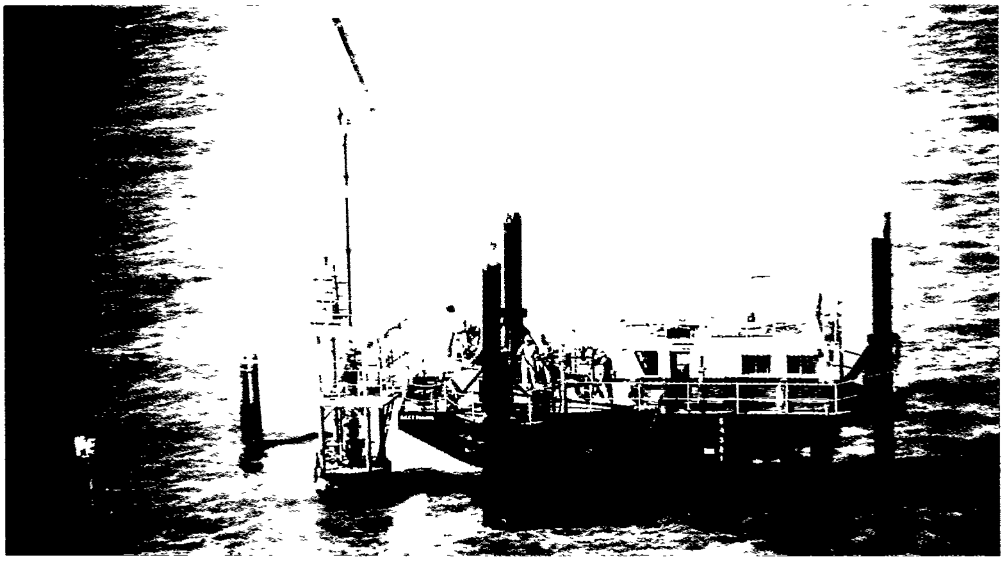
WIRELINE OPERATIONS AND PROCEDURES

THIRD EDITION

BOOK 5 OF THE VOCATIONAL TRAINING SERIES



EXPLORATION & PRODUCTION DEPARTMENT
AMERICAN PETROLEUM INSTITUTE

WIRELINE OPERATIONS AND PROCEDURES

Third Edition

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Exploration & Production Department

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FOREWORD

The third edition of this manual was written to update and outline the application of the various wireline tools, equipment, and operations in the oil and gas industry. The manual does not cover all aspects of the subjects presented. Instead, the basic applications and principles of wireline work are covered in a simple and uncluttered manner.

This manual should be used as an introduction and guide to wireline operations, not as a comprehensive treatise. An individual wishing to learn more should go to the specialized training texts or programs used by the various wireline companies.

Wireline equipment use and technology has been growing steadily, along with significant improvements in wireline capability. This was a natural evolution resulting from the variety of geographical frontiers and well conditions in which the industry operates today, i.e., offshore, arctic areas, deserts, inland waters, etc.

Chapter 1 contains a brief review of early wireline work and a description of surface equipment used in performing various wireline operations. Tool strings and service tools are described in Chapter 2. Subsurface equipment used in completion operations and production control is covered in Chapter 3. Wireline operations, including offshore procedures, are outlined in Chapter 4. Illustrations are used throughout this manual to make the words easier to understand.

Preparation and review of all material in the third edition of this manual — the fifth in the API Vocational Training Series of publications dealing with various oilfield operations — was accomplished by a Task Force appointed by the API Executive Committee on Training and Development.

Other publications in the API Vocational Training Series are:

Book 1: *Introduction to Oil and Gas Production*, American Petroleum Institute, Production Department.

Book 2: *Corrosion of Oil- and Gas-well Equipment,* American Petroleum Institute, Production Department. (Sponsored jointly by National Association of Corrosion Engineers and American Petroleum Institute.)

Book 3: *Subsurface Salt Water Injection and Disposal,* American Petroleum Institute, Production Department.

Book 6: *Gas Lift,* American Petroleum Institute, Production Department, 1994.

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CHAPTER 1
SURFACE EQUIPMENT

INTRODUCTION

Wirelines have been in use since the early days of the oil and gas industry. The development of surface equipment for solid wireline operations has kept pace with the development of new methods and tools used in well completion, remedial and work-over operations. Solid wireline is used for depth determination, deviated hole surveys, temperature and pressure surveys, paraffin cutting, and cementing operations. Solid wireline may also be used to set, retrieve, and manipulate chokes, circulating plugs, gage cutters, swaging tools, safety valves and gas-lift valves.

As the oil industry grew from the first shallow well in Titusville, Pennsylvania in 1859 to the first producing well on the Outer Continental Shelf in the Gulf of Mexico in 1947, wireline servicing also grew in complexity. Since then, wireline operations have kept pace with industry needs for work in deeper and more corrosive wells, deviated holes, and wells drilled in deeper water offshore.

The expansion of oilfield activities from conventional terrain to marsh, muskeg, desert and offshore locations has required mobility in wireline equipment for proper servicing.

In the early days of solid wireline operations few problems occurred with mobile equipment. Trucks with wireline winches, skid-mounted equipment, and fixed units mounted at strategic locations handled most solid wireline work. The truck is now the primary transport vehicle for wireline land operations.

Wireline equipment was later moved to inland water and marsh locations by mounting the equipment on speed boats, tugs, or small barges. Today a diesel powered shallow water spud boat, with a built-in hydraulic system that controls the wireline spool as well as the boat spuds, is usually used in bayous, streams, marshes or lakes.

As oilfield development moved offshore, equipment and methods of transportation changed. Self-propelled jackup vessels are ordinarily used on shallow water locations. The jackup vessel is built on the same principle as a spud barge, except that the spuds are replaced with long legs to jack the boat out of the water. This enables the crew to work in rough seas and water depths of up to a hundred feet or more.

In remote offshore areas a specially designed skid-mounted diesel-powered wireline unit with built-in hydraulic pumps and motors is used. The unit is transported to the offshore platform or rig on a supply boat and lifted onto the platform by a crane.

Drilling and completion of oil and gas wells in desert terrain is accomplished by mounting the equipment on large-wheeled vehicles (trucks or cars) capable of driving in soft sand. Wireline equipment is moved to desert locations the same way.

Weather conditions in arctic areas call for specially designed cold weather units; however, these are also easily transportable by truck to remote locations.

Since early days when the operator used a small hand crank and spool containing a short length of solid wire, many mechanisms have been developed for supplying the power source to turn the wireline spool. When the solid wireline proved a practical means of depth determination, and the need for greater depth runs developed, the power source also changed. Many new methods of rotating the reel came into use, such as: gasoline engines equipped with speed-reduction devices; diesel engines; electric motors; and hydraulic pumps and motors.

Due to fire hazard on offshore locations, a number of operators have restricted the use of sparking power sources and actuating devices. Diesel wireline units operating on the Outer Continental Shelf are required to be equipped with spark arrestor mufflers and shut down devices on the air intakes.

Transporting the wireline and associated equipment to a location is obviously a necessary part of the job. Surface equipment to be used at the wellsite is likewise an obvious necessity.

The surface equipment required to perform wireline operations depends largely on the well pressure and tubing size. Figure 1-1 shows the standard components used in a normal wireline operation on a well with less than 5000 psi surface pressure and $2^1/_2$ inch ID tubing. The surface equipment list corresponds to the item numbers in Fig. 1-1.*

*A certain amount of flexibility must be considered when rigging up the surface equipment. The components are named and numbered only for identification by the reader as they are discussed in this chapter.

WIRELINE

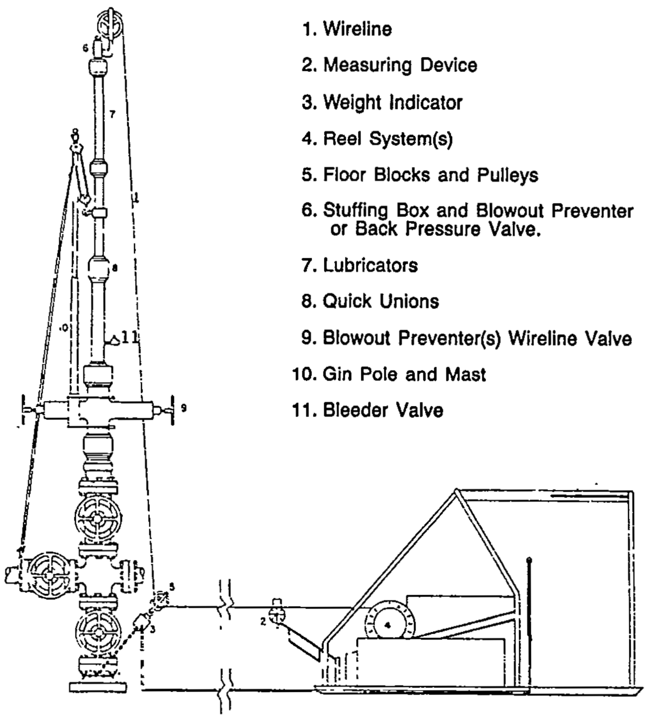

Fig. 1-1 — Wireline surface equipment (Example of an arrangement)

The earliest wireline used in measuring well depth was a flat steel tape with marked or stamped figures indicating footage, similar to a surveyor's tape. As well depths increased, tape of sufficient length became difficult to obtain. Correct depth readings were also a problem — stretching of the calibrated tape under load caused inaccurate measurement. When the flat tape was lowered into a well under pressure, the stuffing box and pack-off added to the problems. These disadvantages brought about the adoption of the solid wireline for depth measurements and pack-off control. The line was tagged at equal increments of length and the operator kept a record of the amount of line reeled in and out. Later, measuring devices with calibrated wheels came into use because they were more convenient and provided accurate measurements. The measuring device is discussed in detail later in this chapter.

Solid Wireline

Deeper wells and heavier loads imposed on the measuring lines necessitated development of high-strength steel wireline to minimize weight of the wire and size of the hoisting equipment. A small-diameter wire was developed with the following results:

1. Reduces the load due to its own weight.
2. May be lowered over a small-diameter sheave.

TABLE NO. 1
WELL-MEASURING WIRE SPECIFICATIONS
(Solid Wireline)

1	2	3	4	5	6	7
Nominal Diameter in.	0.066	0.072	0.082	0.092	0.105	0.108
mm	1.68	1.83	2.08	2.34	2.67	2.74
Tolerance on diameter in.	±0.001	±0.001	±0.001	±0.001	±0.001	±0.001
mm	±0.03	±0.03	±0.03	±0.03	±0.03	±0.03
Breaking strength						
Minimum lb	811	961	1239	1547	1996	2109
kN	3.61	4.27	5.51	6.88	8.74	9.38
Maximum lb	984	1166	1504	1877	2421	2560
kN	4.38	5.19	6.69	8.35	10.77	11.38
Elongation in 10 in. (254 mm), per cent						
Minimum	1½	1½	1½	1½	1½	1½
Torsions, minimum number of twists in 8 in. (203 mm)	32	29	26	23	20	19

*For well-measuring wire of other materials or coatings, refer to supplier for physical properties.

3. May be wound on a small-diameter spool or reel without over-stressing by bending, keeping the size of the reel drum to a minimum.

4. Provides a small cross-sectional area for operation under pressure.

The most common diameter sizes of solid measuring line currently in use are: 0.066, 0.072, 0.082, 0.092 and 0.105 inch. Larger diameter line, 0.108 and 0.125 inch, are being used to some degree in wells with tubing strings larger than $2^1/_2$ inch ID. Measuring lines are available from the mills in one piece in standard lengths of 10,000, 12,000, 15,000, 18,000, 20,000 and 25,000 feet. The most popular material, because of its high ultimate tensile strength, good ductility and relatively low cost, is improved plow steel. Cold-drawn improved plow-steel measuring line has an ultimate tensile strength of approximately 230,000 to 240,000 psi. API Specification 9A, *Specification for Wire Rope** contains a section on well-measuring wire specifications. Table No. 1 contains requirements from API Spec 9A as well as information developed for this manual.

No wireline manual would be complete without mentioning Hydrogen Sulfide (H_2S) sometimes referred to as "sour gas", and Carbon Dioxide (CO_2). Many wells drilled in the past few years have been deeper completions in sour gas reservoirs. Severe corrosion, excessive temperatures and pressures — plus depth — have introduced many wireline problems that were unknown a few years ago. When corrosive components are encountered in a well, cold-drawn improved plow-steel lines may be affected by hydrogen embrittlement resulting in reduced service life. For service in hydrogen sulfide atmospheres, Type 316 stainless steel is recommended because of its resistance to hydrogen embrittlement. The ultimate strength of stainless steel measuring line is lower than that of improved plow-steel, its cost is appreciably greater, and it is less ductile. It is more susceptible to cold working which results in brittleness and reduction of service life. There are several methods which can be used in wireline operations to reduce or eliminate potential problems where corrosive environment is present. These methods are discussed in Chapter 4 — Wireline Operations.

Stranded Line

Stranded line is commonly used to replace solid line when line size is larger than 0.105-inch and added strength is required. This line is available in the following sizes: $^1/_8$ inch (0.125), $^9/_{64}$ inch (0.141), $^5/_{32}$ inch (0.156), $^3/_{16}$ inch (0.187), $^1/_4$ inch (0.250), and $^5/_{16}$ inch (0.312).

Wireline Handling

In order to realize good service and maximum life from wireline, it is necessary to take certain precautions in its handling and usage. Figure 1-2 shows the right and wrong practices when transferring or rewinding wireline.

1. Properly transferring the measuring line from the shipping spool to the reel is very important for extending the performance and service life of the line. Fig. 1-2(A) shows a recommended setup for rewinding so that the curvature of the line is not reversed. Fig. 1-2(B) shows an *improper setup.* Improper winding causes reverse bending of the line, making the line more difficult to handle, and causing it to kink and tangle. Fig. 1-2(B) shows a less desirable arrangement than Fig. 1-2(A) because it induces a partial reversal in the line, but does not affect the line as severely as the method shown in Fig. 1-2(C). Exercise caution in using this method, as there is a greater tendency for the line to cut into the wooden flanges of the spool, if it becomes misaligned. Line tension is increased by frictional drag of the spool on the ground. Best results are obtained when both spool and reel are mounted on horizontal shafts and spaced far enough apart to make level winding easier and reduce undercutting.

2. Avoid gripping the line with tools, such as pliers or hardened jaws. Nicking or gouging the surface of the wire can cause failure when the line is subjected to tensile and bending stresses.

3. Uncontrolled slack and resultant kinking must be avoided.

4. When retrieving the line from the well, clean the line of well fluids (See p. 8, Line Wipers), and give it a protective coat of oil as it is reeled onto the drum.

5. Do not pull a line beyond its elastic limit.

6. Before beginning a job or at frequent intervals during extended work periods, cut 15 to 20 feet of line off the spool and tie another knot.

There are times when a line may need changing because of

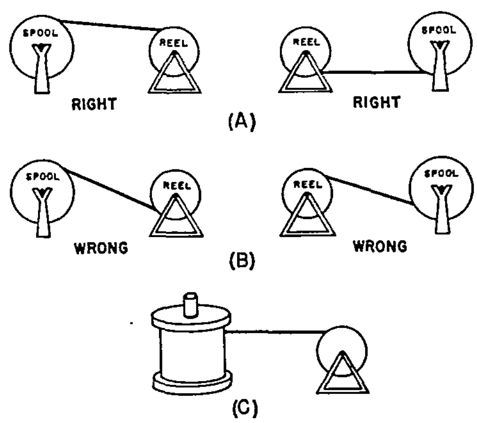

Fig. 1-2 — Recommended method for respooling or transferring measuring line.

continuous use, damage, or lack of care. Some ways of detecting a bad line are:

1. When a line is laid out on the ground and does not form a coil or loop as on the drum. This indicates the line has exceeded its elastic limit and is considered a "dead" line.
2. When tying a knot, the wireline breaks easily. Remove a few feet of line and tie a new knot.
3. When kinks will not straighten out. This indicates the line has been subjected to extreme tensions or stress. Change the wireline.

MEASURING DEVICES

One of the most important pieces of wireline equipment is the measuring device, Fig. 1-3. It is a necessity on any job, whether it is simply measuring a shallow well with a lead weight on the end of the measuring line, a delicate logging survey, or the intricate setting or retrieving of a variety of special tools in the deepest known wells. In order to perform any type of wireline operation efficiently and safely, the operator must know the location of the tool with relation to the wellhead or other reference point. Knowing the location of a tool as it approaches the wellhead during retrieval enables the operator to control its speed and bring it to a stop before hitting the wellhead sheave or stuffing box. This will help to prevent a fishing job or damage to the tool.

A mechanical measuring device that has proven accurate, rugged and reliable with minimum maintenance is one which holds the measuring line in slip-free contact with an accurately ground, hardened measuring wheel driving a counter or odometer for registering the linear units (meters or feet) of line contacting the measuring wheel. The measuring device is generally mounted on moveable supports to allow it freedom to move.

When the measuring wheel is worn, the counter or odometer will give false readings and the wheel should be replaced. If not replaced, damage could occur by the "shaving" of the wire from the grooves cut into the measuring wheel. During extended jarring operations, it is recommended the wire be temporarily removed from the assembly. This will prevent the stress associated with the repeated bending/straightening of the wire around the measuring wheel. In addition, counter wheels are wire size specific and are not interchangable. For larger sizes of wire (.105, .108 and .125") the counter wheel and stuffing box sheave diameter must be increased to prevent over-stressing the line which would cause hardening. Care should also be taken to avoid over tightening the pressure wheels, which would result in the flattening of the wire and reduced life of the line. Under tightening of the pressure wheels or worn counter wheels will give false odometer readings.

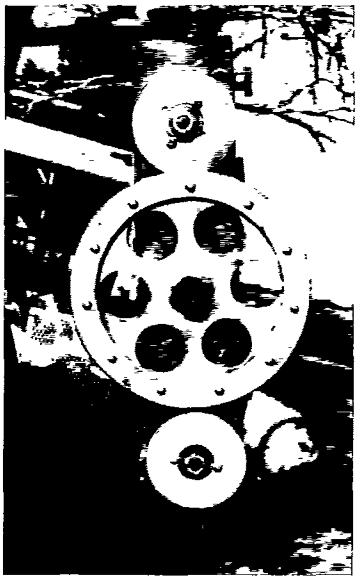

Fig. 1-3 — Measuring device

WEIGHT INDICATORS

In heavy-duty wireline operations when it is necessary to load the measuring line to its maximum safe load (usually in connection with mechanical or hydraulic jars), the use of some type of weight-indicating device is necessary. Various types in use are: Mechanical, Hydraulic and Electronic. A hydraulic weight indicator is shown in Fig. 1-4. These instruments are calibrated in pounds (or metric equivalents), and indicate the total load on the line at the weight indicator. These indicators are either incorporated into, or designed as attachments, to the measuring devices.

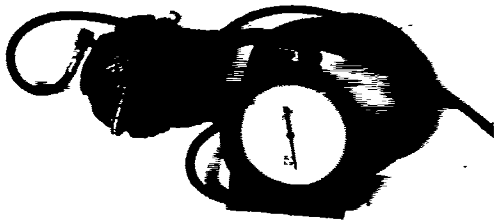

Fig. 1-4 — Hydraulic weight indicator

REEL SYSTEMS

Wireline reels make it possible to conveniently and safely handle continuous measuring lines in performing wireline operations. Reels are necessary to transport the line from one wellsite to another without damage. Basically, the wireline reel is a spool of sufficient size to accommodate the required length of line to perform the job. The small measuring reels do not require a power source to lower a tool into the well. The weight of the line and tools is sufficient to unwind the line from the reel. However, all present day reels have provisions for some type of power source. On the larger reels where slow or constant speeds are desired, transmission or hydraulic brakes are used to lower the tool(s) into the well. Other necessary components on the reel assembly are: reel drum brake; clutch for disconnecting from the power source; power source start-and-stop controls; and speed controls where applicable. When a wide range of operating speeds is required, multi-speed mechanical transmissions are sometimes used.

Different types of measuring-reel mountings are:

1. Skid or base-mounted — portable (Fig. 1-5)
2. Truck-mounted — truck-engine-driven (Fig. 1-6)
3. Trailer-mounted (Fig. 1-7)
4. Boat-mounted — Engine-drive (see cover picture)
5. Automatic paraffin scraper mounted on wellhead.

On most current offshore wireline jobs, double drum units (two reels) are used. One is for routine wireline work, and has approximately 20,000 feet of 0.082-inch diameter solid line. On the other reel is approximately 20,000 feet of $^3/_{16}$ inch stranded line which is used for heavy pulling, such as swabbing or fishing operations. The reels and hydraulic controls are mounted on a separate skid from the power unit. Separation of the two is necessary to reduce the weight and ease the transfer from a supply boat to the offshore platform with a minimum size crane.

The newest type of single-reel hydraulic unit for a routine wireline operation is a compact system with the power section built on the same skid, because it is easily portable it is used extensively in offshore operations. However, because of its light weight it should always be properly secured to prevent movement and possible injury.

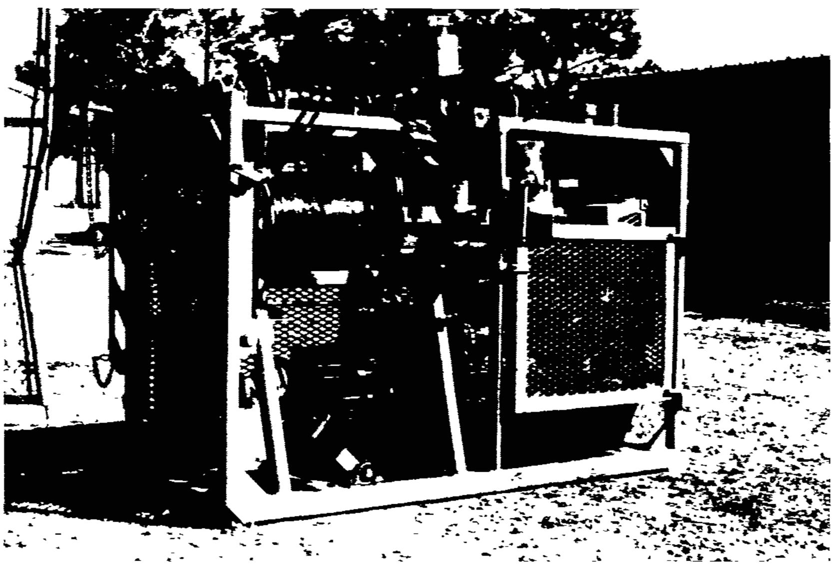

Fig. 1-5 — Skid or base-mounted (portable) measuring reel mounting

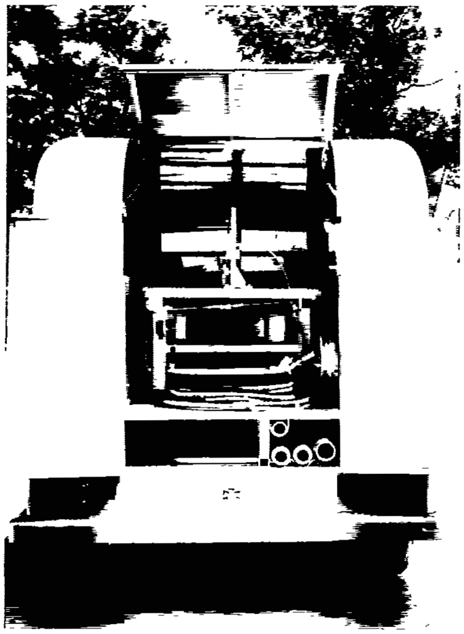

Fig. 1-6 — Truck-mounted — Truck engine driven measuring reel mounting

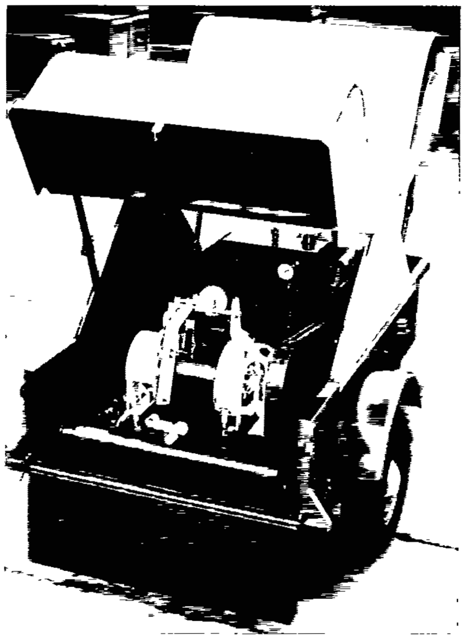

Fig. 1-7 — Trailer-mounted wireline reel

FLOOR BLOCKS OR PULLEYS

When the wireline is routed from the reel to the stuffing-box sheave, conditions may require changing the direction of the line several times. Floor blocks or pulleys with sheaves, properly sized to prevent over-stress in bending, are used for this purpose. Snatch-block type pulleys are generally installed on the line to keep from having to thread the end through the pulley supports, Fig. 1-8. Note that the pulley is attached to the load cell of the weight indicator. For accurate weight indicator operation the angle the wire makes around the pulley should be 90 degrees. Also position the pulley as close as possible to the lubricator to prevent side loading.

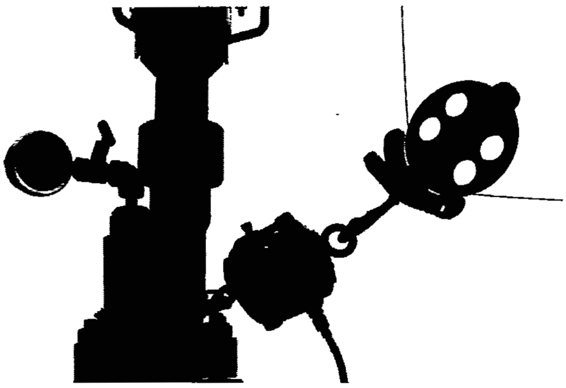

Fig. 1-8 — Snatch-block type pulley

STUFFING BOXES

Wireline stuffing boxes (Fig. 1-9) are used when it is necessary to perform work on a well under pressure. The stuffing box consists of a packing chamber with an external adjustable nut. The nut is either manually or hydraulically tightened to minimize leakage around the line resulting from well pressure. In most cases the stuffing box provides a swivel bracket and sheave which guides the measuring line down into the packing gland. The radius of the stuffing box sheave must also be changed to accommodate larger size wirelines.

Heavier stuffing boxes can be equipped with a bleedoff assembly and a place for setting a blowout preventer (not a wireline valve). The purpose of a blowout preventer is to shut-off the well flow through the stuffing box in the event the packing is cut, blown out, or the wire breaks.

When stranded line is used in wells under pressure, the multiple lays in the construction of the line make it difficult to seal off the well. For this reason, a stuffing box was designed with a grease seal. The grease is pumped into the stuffing box under pressure, forming a barrier against the flow of wellhead fluids or gases. This completely seals the flow and lubricates the line. This grease-seal stuffing box is used by all wireline companies (including electric line) whenever line is required.

Fig. 1-9 — Stuffing Box

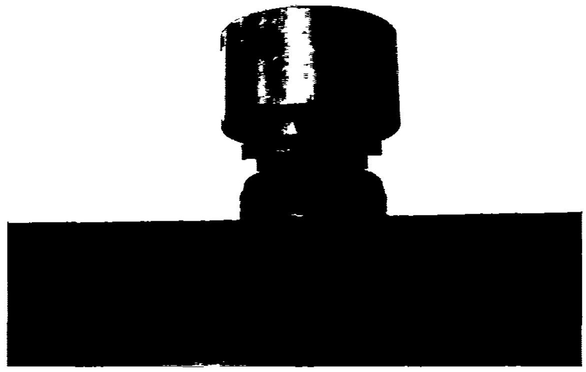

Fig. 1-10 — Quick union

LUBRICATORS

A lubricator may be described as a number of tubular sections of pipe assembled together with a stuffing box to pack off the wireline on top. The tubular sections are assembled on the ground (or platform) and held together with quick unions. The entire assembly is then raised to a vertical position above the wireline valve. The size and length of the assembly must accommodate the workover tools, any "fish" that might possibly be recovered, and have a working pressure rating equal to or higher than the string of pipe through which the tools are lowered. The lubricator is generally standard in length — just high enough to handle the longest string of tools between the wireline valve and the stuffing box and is easily transported to and from the location. For offshore wireline operations, the lubricator may be as long as twenty feet without the union connectors: however, most boats and platforms are equipped with either hydraulic gin poles or cranes so the length and weight present no problem.

Specially designed lubricators are used when problem situations arise, such as exposure to "sour gas" (Hydrogen Sulfide) or Carbon Dioxide. The lubricator is generally constructed of low alloy steel, heat treated and softened to comply with National Association of Corrosion Engineers (NACE) Standard MR-01-75, 1978 Revision, Section 11.9.5. Lubricators should be tested as referenced in 30 CFR 250 or API 14B. Test the lubricator to maximum anticipated well pressure, but do not exceed the manufacturer's recommended working pressure.

QUICK UNIONS

Quick unions are connectors which are screwed or welded on each end of all lubricator sections, and are designed with an O-ring type seal to hold the well pressure (Fig. 1-10). As a safety feature, one half of the union slips inside the other half union and is secured by a large nut which is screwed to the female half. It should not be disconnected while there is pressure on the lubricator.

WIRELINE VALVES

The wireline valve is a ram-equipped device used on the wellhead to prevent or control blowouts, Fig. 1-11. In addition to providing positive protection against blowouts, the wireline valve is a means of isolating the well pressure from the lubricator without cutting or damaging the line. This is often necessary during wireline fishing operations. It is accomplished by manually or hydraulically pressing together a set of rams made of resilient packing to form a seal. Once the valve is closed, the lubricator can be bled off.After removing and changing wireline tools, the lubricator must be repressurized before opening the rams. This is done by opening a special equalizing valve on the side of the wireline valve. It allows the well pressure to be routed around the closed rams into the lubricator. Then the rams can be easily opened without damaging the tool string or lubricator. Regulation governing offshore wireline operations require the use of at lease one wireline valve. The valve should be pressure tested before beginning any job. Test the wireline valve to the maximum anticipated well pressure, but do not exceed the manufacturer's recommended working pressure.

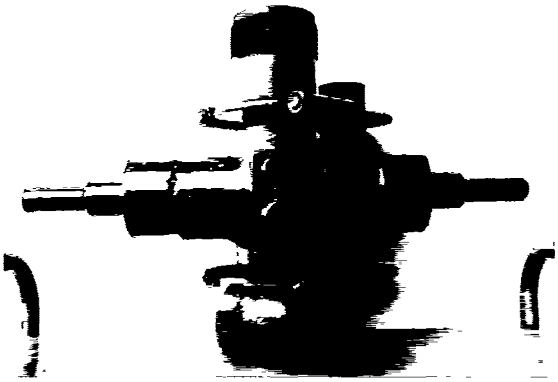

Fig. 1-11 — Wireline valve (Blowout preventer)

LINE WIPERS

When retrieving the wireline from a well, the fluid clinging to the line drips or is thrown off the floor blocks and pulleys, creating a possible safety, maintenance and housekeeping problem. Line wipers of various types generally do a very effective job of cleaning the line at or near the wellhead. One form of line wiper is a housing with an internal split neoprene rubber plug. This plug has a threaded bolt adjustment that compresses the rubber plug until it envelopes the line and strips it of fluid. This line wiper has a hinge pin to anchor it to the floor block or pulley frame for alignment on the line. Other types are built on the same principle as the stuffing box, containing packing and an adjustable gland for cleaning the line. Oil from the wiper should be collected in a suitable container.

GIN POLES OR MASTS

During wireline work-over operations when it is necessary to use tall high-pressure lubricators and heavy tool strings, removing and replacing the heavy loaded lubricator off and on the wellhead becomes a problem. A stiff leg, with a block and tackle, electric hoist, or mast-type structure (Fig. 1-12) mounted on a truck is sometimes used to handle the lubricator. When the work is performed on a rig, an air hoist or cat line can be used. Wireline boats have a special mast or crane to do the job. On offshore platforms, a platform crane, or an A-frame type structure over the well is used. However, it is recommended that a gin pole and a block and tackle be available as a backup, in the event other means of lifting is not available.

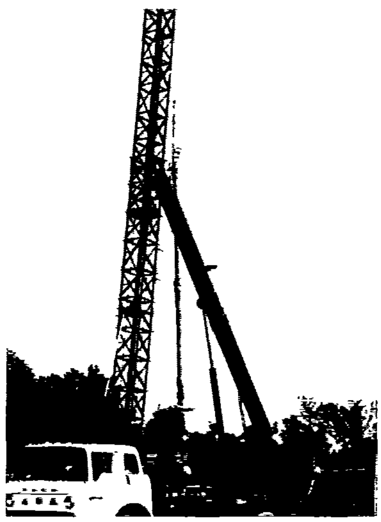

Fig. 1-12 — Truck mounted rig

CHAPTER 2
TOOL STRING AND SERVICE TOOLS

INTRODUCTION

Various tools frequently used in wireline operations are described in this chapter. Descriptions of special fishing tools are included, along with their application to fishing jobs which sometimes occur during wireline operations.

WIRELINE TOOL STRING AND SERVICE TOOLS

Wireline Socket

The wireline (rope) socket (Fig. 2-1) fastens the wire to the tool string. The most common rope socket consists of a body, spring, spring support, and disc. The body is bored to accommodate the inner parts, accept the wireline through the upper end and the stem from below. Near the upper end is a fishing neck that accepts pulling tools in standard sizes. Above the fishing neck, the body is tapered to guide the pulling tool and facilitate its engagement. The flat on the upper end is a striking surface to prevent peening the metal and closing the wire hole, if the socket is subjected to jarring during fishing or other operations.

The spring acts as a shock absorber to prevent the knot from failing under severe impact, as during jarring operations. The spring support centers the disc and the load so that the force applied is a straight pull.

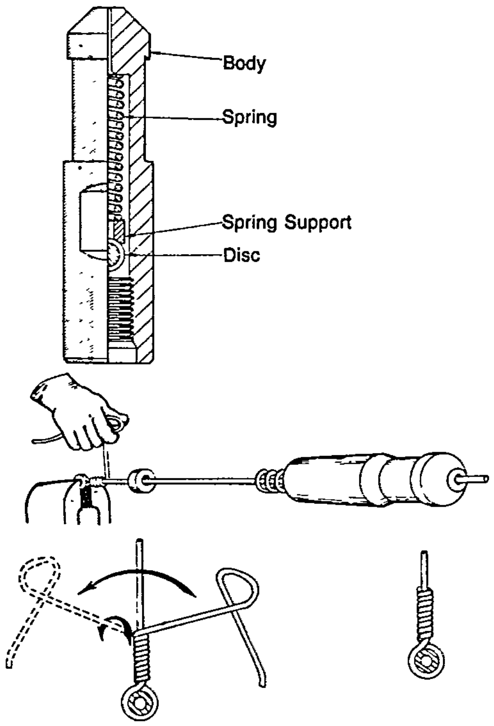

Fig. 2-1 — Wireline (rope) socket and knot-tying techniques

The wireline is fastened to the disc which is grooved around its entire circumference. This groove is deep enough to prevent damage to the line when the disc comes to bear against the spring support. To absorb the punishment to which it may be subjected, the knot fastening the wire to the disc must be tied with great care.

Stranded Line Socket

The stranded line socket serves the same purpose as the wireline socket. It provides the means by which a stranded line is fastened to the tools. It is secured by babbitt instead of being tied around a spool. Slip type rope sockets (Fig. 2-2) are designed to be used with small stranded lines, through $^{5}/_{16}$ inch diameter.

In some instances a rope socket with no knot may have to be used on conventional solid wireline. Conditions such as sour service require using a special metallurgy solid wireline which does not have much capability to withstand torsion effects. A no-knot or wedge-type rope socket similar to the stranded line socket should be used in these cases. However, remember to include a knuckle joint below the rope socket to provide the needed swivel action.

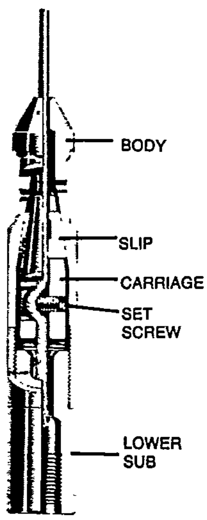

Fig. 2-2 — Stranded Line Socket

Wireline Stem (Weight Bars)

The stem (Fig. 2-3) provides the weight to pull the wireline tool string into the well. The stem also adds the needed weight for jarring operations or shearing metal pins which release running and pulling tools. The stem's influence may be increased or decreased by changing its total weight, i.e., the total number of lengths of stem. To increase weight without increasing length, weighted stems are sometimes used. These are made by using a good grade of 4140 or similar steel tubes and filling them with lead. Box and pin ends are then screwed on the ends and welded in place to keep them from backing off. A stem is essentially a round rod with a pin connection and fishing neck at the upper end, and a box connection at the lower end. Stems can be provided in outside diameters of 3/4 in. 1 1/4 in., 1 1/2 in., and 1 3/4 in. They are usually made in 2-ft, 3-ft, or 5-ft lengths.

Stems also have special applications. They may be used as spacers when it becomes necessary to position tools at a higher level in the tubing. For instance, in perforating operations where a tubing stop has been set, the stem will space the perforation at a slightly higher level, if desired. A stem may also be placed immediately below jars to position them at a higher level in the tubing string when there is a possibility of their being fouled by wire during fishing operations. Other uses will be discussed later in the chapter.

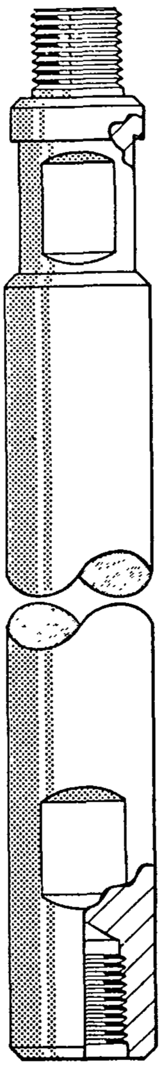

Fig. 2-3 — Wireline stem

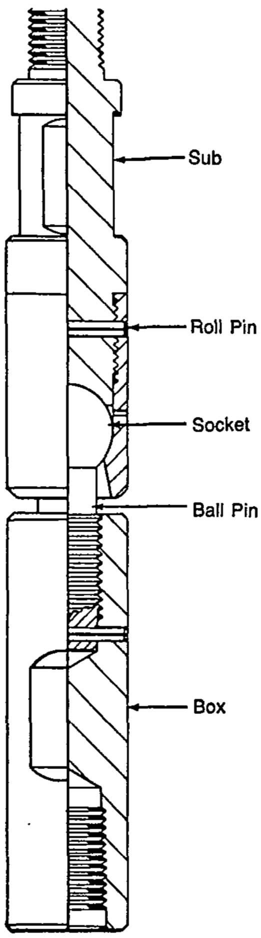

Fig. 2-4 — Knuckle joint

Knuckle Joint

The knuckle joint (Fig. 2-4) is similar to a stem, but has a ball swivel in its mid-section. Its purpose is to provide flexibility in the string of tools to facilitate taking hold of various tools, and to enable the tools to pass through crooked tubing where they might otherwise be fouled. The knuckle joint, when used in the string of wireline tools, should be immediately below the jars where flexibility is important. If crooked tubing is encountered, knuckle joints may be placed between the stem and jars; and, in extremely crooked tubing, between the individual stems.

The knuckle joint should be inspected frequently to make certain that the threads and ball and roll pins are in good condition. If the roll pins become loose, the tool should be sent in for rebuilding to prevent its coming apart in the well.

Wireline Jars

The purpose of the wireline jar is to provide a means of striking the wireline tools while they are in the well. The striking force can be either up or down. Stroke jars, tubular jars, and hydraulic jars are the most common, and they are available in various sizes and strokes.

Stroke jars (Fig. 2-5) are of the cable-tool type and use the weight of stems, connected immediately above, to deliver effective jarring impacts by manipulation of the wireline at the surface. Their effectiveness is largely dependent upon the weight of the stem and length of the stroke. However, the size and depth of the tools, density and viscosity of the fluid in the tubing, well pressure, and even wireline size are factors which must be considered. Stroke jars are composed of two pieces linked together much like long chain links. They are free to be extended or collapsed. In use, a string of tools consists of a wireline socket, one or more stems, wireline jars, and some form of operational tool (running or pulling tool, etc.) This tool string is lowered into the well bore on a solid steel measuring line. Bv manipulating the wireline at the surface, the jars may be extended or collapsed. If they are extended gradually or gently and permitted to collapse abruptly, a downward blow will be delivered. If extended abruptly, an upward impact will result.

The use of 1-1/2 in. outside diameter (OD) stroke jars in pipe larger than 2-1/2 in. inside diameter (ID) is not recommended, as this may allow the jars to bow or buckle and cause a "scissoring" of the two sections thereby preventing them from entering restricted openings. This is especially true when they are used in casing below a string of tubing.

Tubular jars (Fig. 2-6) are ordinarily used in connection with jarring in casing or large tubing, during fishing or sandbailing operations. The jar is tubular in construction, and the tube section is perforated for fluid bypass when the plunger is moved up or down.

Hydraulic jars (Fig. 2-7) are designed for upward jarring only. The impact of the stroke is proportional to the strain on the wireline and the weight of the stem section used above the jars.

Since hydraulic jars do not permit downward jarring, mechanical jars are run in conjunction with and usually below them to provide for downward jarring action. Then, too, if the hydraulic jars fail to function properly because of loss of fluid or gas filtering into the chamber, the mechanical jars may be used to complete the operation. The hydraulic jar consists basically of an oil-filled body, machined internally over a portion of its length to restrict the movement of a tight fitting piston. As the piston moves upward through the body, it delivers the jarring stroke. A balanced piston in the lower body section maintains equalized pressure with the outside hydrostatic pressure. As strain is taken on the line, the piston movement is comparatively slow through the restricted body section because of the smaller annular clearance for the oil to bypass the piston. The jarring stroke occurs as the piston reaches the larger internal body area where the oil bypasses easily to provide rapid movement of the piston against the body insert. After the jar has been tripped, the weight of the stem collapses the piston for another stroke. Hydraulic jars should be checked by collapsing the mandrel, then pulling on the top sub while holding the lower sub. If the mandrel moves easily or has a springing action when released, the jar is not functioning properly and should be repaired.

Knuckle jars (Fig. 2-8) are items of accessory equipment on wireline units and are similar in construction to the knuckle joint. The difference is that the knuckle jar has a floating ball within a 4-in. socket and, in effect, is a tubular jar. Knuckle jars are commonly used as a means of jarring the stem loose

Fig. 2.5 — Stroke jar

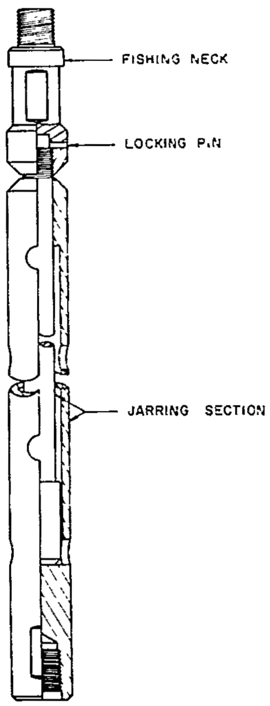

Fig. 2-6 — Tubular jar

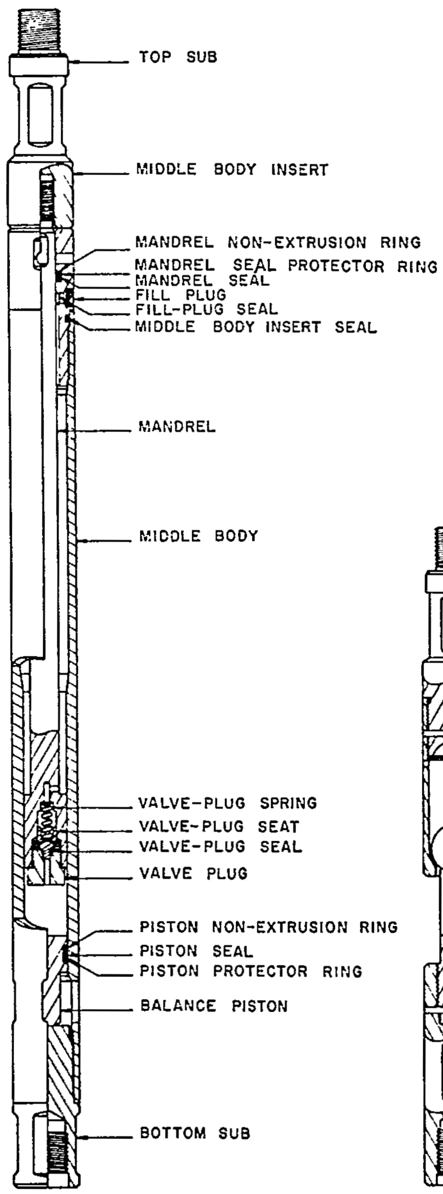

Fig. 2-7 — Hydraulic jar

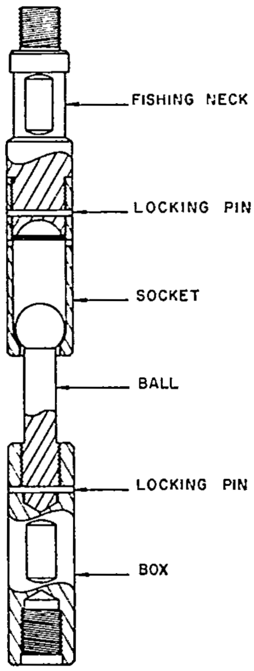

Fig. 2-8 — Knuckle jar

from wedged places in the tubing when mechanical jars are fouled. With proper handling, the knuckle jar can be used to advantage as a jarring mechanism, but is not recommended for such use except in an emergency.

The explosive jar strikes downward with an explosive force that drives a hammer. (The knuckle joint and upper barrel of the perforator are used for the explosive force.) It can be reloaded and used again. The main purpose of this jar is to strike a hard downward blow when it is necessary to knock loose a stuck choke or similar control. It can also be used to put a hole through a bull plug or to take a deep impression with an impression block. It is almost impossible to get a mechanical jar to hit hard enough to loosen a stuck choke in an extremely deep or crooked hole. The explosive jar can therefore be of great value.

The tension jar accomplishes the same purpose as the hydraulic jar, except that this jar is spring loaded and the action is mechanical rather than hydraulic.

TUBING CONDITIONING TOOLS

Tubing Gage

A tubing gage (Fig. 2-9) should be run prior to running or pulling a subsurface control. This assures the operator that the tubing is unobstructed. This tool may also be used as a paraffin cutter.

Paraffin Scratcher

There are several types of tools used to cut or scratch paraffin. Fig. 2-10 shows one type of paraffin scratcher. It can also be used to scrape the tubing wall, clean landing nipples, and fish small pieces of wireline loose in the well. It is usually run before running the tubing gage.

Tubing Swage

A tubing swage (Fig. 2-11) is designed to swage out tight or mashed places in the tubing string. The outside diameter of the swage is the same as the drift diameter of the tubing.

Tubing Broach

A broach is a tool run to remove metal burrs and imperfections from the tubing wall prior to running or pulling service tools. It is equipped with graduated rings, diamonds, or segments that are case hardened and highly sharpened. One form of tubing broach is shown in Fig. 2-12.

Blind Box

A blind box (Fig. 2-13) is a service tool used when heavy downward jarring is required. The tool is flat on the bottom and hardened so as not to damage easily.

Impression Block

An impression block (Fig. 2-14) is a lead or babbit filled cylinder with a pin through the leaded section to prevent losing the lead. This tool is used during fishing operations to ascertain the shape or size of the top of the fish and may indicate the type of tool necessary for the next operation.

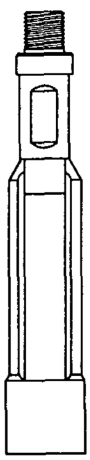

Fig. 2-9 — Paraffin cutter or tubing gage

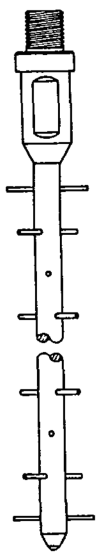

Fig. 2-10 — Paraffin scratcher

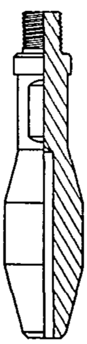

Fig. 2-11 — Tubing swage

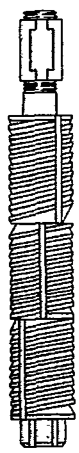

Fig. 2-12 — Tubing broach

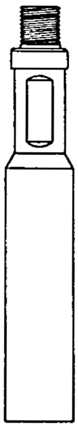

Fig. 2-13 — Blind box

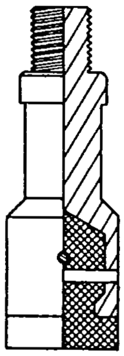

Fig. 2-14 — Impression block

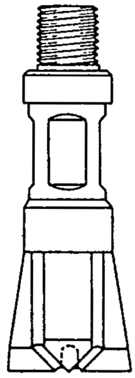

Fig. 2-15 — Star bit

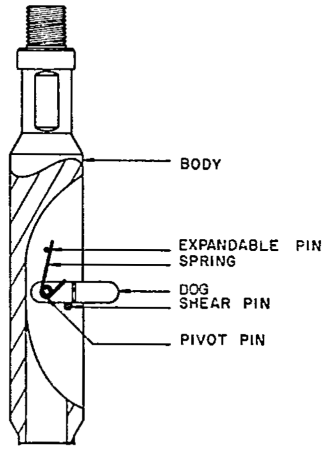

Fig. 2-16 — Tubing end locator

Star Bit

The star bit (Fig. 2-15) has blades on the bottom to cut or break up debris in the hole to drive the debris through an intended workover interval.

Locator Tools

These tools are designed to locate seating nipples, the bottom of the tubing, and the bottom of the well bore all in one wireline trip.

The tubing-end locator (Fig. 2-16) is used to accurately locate the end of the tubing string. Before the tool is run, it is imperative that tubing is cleared by running a tubing gage or bailer. This ensures that the locator will pass through the end of the tubing. A paraffin scratcher may also be used to locate the end of the tubing, eliminating the need for the tubing-end locator.

Sand Bailer

The sand bailer (pump type, Fig. 2-17) is designed to remove sand, mud, salt, paraffin, shale, or other debris from the tubing or casing. It may also be used as a bottom hole sampler.

Hydrostatic Bailer

The hydrostatic bailer (Fig. 2-18) is a cylinder or barrel about 5 ft. long, with a shear disc mechanism on bottom. The cylinder is sealed off from well pressure with O-rings, and is lowered into the well at atmospheric pressure. When the obstruction is reached, the shear disc is broken by downward jarring. This sheared disc allows the full well pressure and hydrostatic head to enter the cylinder with a sudden surge. The sand or debris is prevented from falling out by a check. This tool should be used only when attempting to remove debris from above a subsurface control or some object that will prevent it from burying itself. (See page 40)

Wireline Spear

The wireline spear, or grab (Fig. 2-19) consists of a housing with one, two, or three prongs with pointed barbs welded to the inner side. This tool is used to fish wireline that has broken in the well.

Wireline Retriever

This tool (Fig. 2-20) consists of a slotted guide and skirt, with a tapered spear point connected to a moveable inner mandrel. The full gage skirt forces the "straight standing" end of the broken wire past the spear point and slotted guide. When the inner mandrel is moved up, the wire is locked on the slip. This tool is especially useful and necessary when fishing for embrittled wire because retrieving does not require bending or crimping the line.

Magnetic Fishing Tool

The magnetic tool is used to fish from the well bore any small metallic object that would be attracted to a magnet.

Non-Releasing Pulling Tools

The non-releasing pulling tool is designed to fish cylindrical necks or tools that have no standard fishing neck. It should only be used in a final effort to retrieve subsurface devices when other releasing tools have failed. There are several types available. One is an overshot, shown in Fig. 2-21. It should be run with a rope socket and in conjunction with a releasing pulling tool to give the operator the advantage of being able to shear off at the pulling tool if needed.

Releasing Pulling Tools

Pulling tools are used to retrieve subsurface tools that have a standard fishing neck. They consist of a skirt and multiple dogs screwed onto a spring loaded core. The core has a brass or steel shear pin, which can be sheared by either jarring up or down, depending on the type of tool. Jarring releases the pulling tool from the subsurface tool when it cannot be retrieved. These tools can be repinned many times to add or subtract stem, or change the tool hookup before running back in the well.

Kickover Tool

The kickover tool is used to selectively locate mandrels that house retrievable side-pocket equipment. They can be of either orienting or non-orienting design.

Cutter Bar

A cutter bar is a stem with a blind box attached to the bottom. It is used to cut off line at the wireline socket.

Go-Devil

A go-devil is a slotted stem with a fishing neck. It is used when the tool string is entangled in or below the wireline. This fishing tool is illustrated in Fig. 2-22 and its operation described in Chapter 4.

Wireline Cutter

The wireline cutter (Fig. 2-23) utilizes a small cylindrical knife section within a slotted body to cut any solid line either within or below the tubing by simply attaching the slotted assembly around the line and dropping it into the tubing. The line is cut as the tapered knife and snipper move together upon impact against the wireline socket or a solid object.

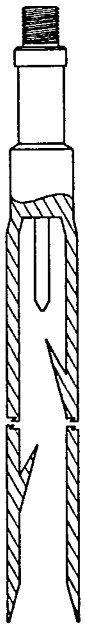

Fig. 2-19 — Wireline spear

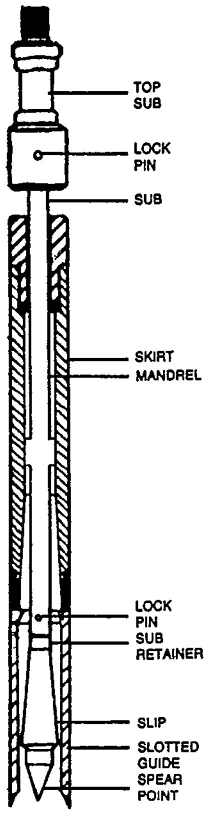

Fig. 2-20 — Wireline retriever

Fig. 2-17 — Pump-type bailer

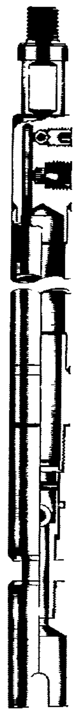

Fig. 2-18 — Hydrostatic bailer

Sidewall Cutter

This tool is equipped with knives that overlap a tapered mandrel to cut the line against the tubing wall. It is used when the tools are stuck, the line has not parted, but the tools have been blown up the hole. It can be run with the tool string and set at any point in the tubing. Fig. 2-24 is a diagram of a sidewall cutter.

Shifting or Positioning Tool

The shifting or positioning tool is used to open or close a sliding side door or sliding sleeve. It may also be used as a nipple locator. Several types are available.

Tubing and Casing Caliper

Calipers are instruments for detecting and recording the internal condition of the tubing or casing. They may be run on wireline under pressure. Typical caliper instruments are shown in Fig. 4-10.

Bottom Hole Pressure Gage (Bomb)

This instrument is used to record bottom hole pressure and temperature. It is usually run on a conventional wireline.

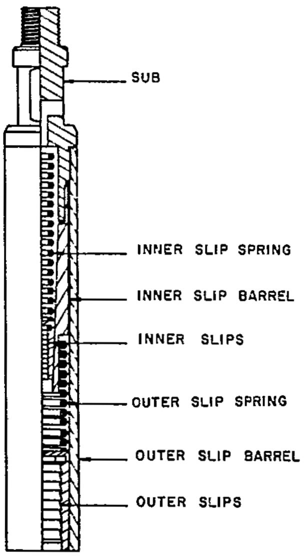

Fig. 2-21 — Overshot non-releasing pulling tool

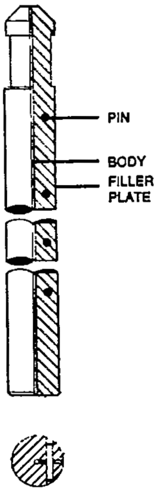

Fig. 2-22 — Go-Devil

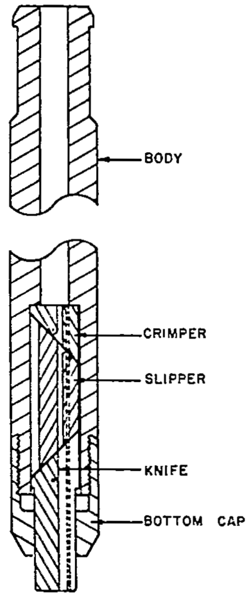

Fig. 2-23 — Wireline cutter

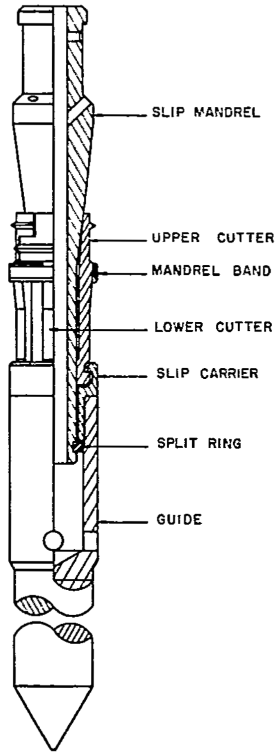

Fig. 2-24 — Sidewall cutter

Alligator Grab

The alligator grab is a tool used to pick up small objects that may have been accidentally lost or dropped in the well. It is designed with jaws similar in shape to those of an alligator, which are pinned open before running into the well. These jaws snap closed when contact is made with the fish, and are held closed by the tension of a coiled spring.

Tubing Perforator

This is a tool run on wireline to perforate a hole in the tubing to perform remedial work. Both mechanical and explosive type perforators are available. The tool is more fully described in Chapter 4.

Choke Extractor

The extractor was primarily designed to pull side-door chokes when pressure in the casing-tubing annulus is greater at the landing nipple than the pressure inside the tubing.

The choke extractor (Fig. 2-25) is pressure-operated and is used in conjunction with pulling tools. It consists of a sub to attach a pulling tool, a fishing neck, an equalizing sub, two choke cups which are mechanically expanded, and a spring-loaded ball which prevents flow through the extractor.

In wireline operations, when the foregoing conditions exist and normal pulling operations are used, a pressure over-balance in the casing causes the tools and side door to be blown up the hole and the wire to ball up when the lower packing passes over the side-door ports.

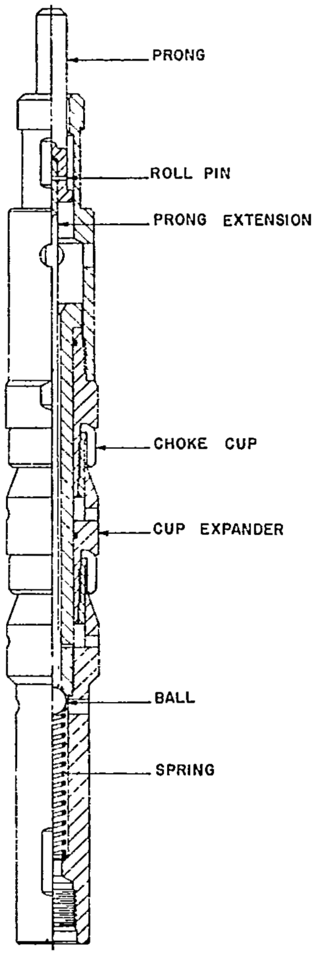

Fig. 2-25 — Choke extractor

The extractor also has uses for pulling heavy loads that are not practical for wireline operations. When pressure conditions are such that a differential can be taken across an extractor, a nest of wire can be pulled; tools entwined in wire and dragging excessively can usually be extracted.

Design of the extractor is such that if a subsurface control is not pulled and the pin in the pulling tool does not shear, a small port allows pressure to equalize across the extractor before an attempt is made to pull with another pulling tool. Also, if it is necessary to pump through the extractor, the spring-loaded ball allows flow through the assembly.

An extractor should not be used near the surface especially in gas wells. A sudden release of an extractor with a high differential near the surface may cause damage to wellhead connections, and may even blow surface connections away and cause a well to become wild.

When running extractors, be sure the equalizing port is open. When pulling them, be sure no pressure differential exists across the extractor.

SAND BAILING AND WIRELINE FISHING

Sand Bailing

Sand bailing is a complex operation requiring patience and perseverence. When sand accumulates in the tubing, it is usually in the form of a bridge that can be removed by making a few trips with a sand bailer. However, at times an operator may encounter a bridge with 100 ft or more of sand. This takes much longer to remove.

There are several types of sand bailers available (See Fig. 2-17 and 2-18). All of them can successfully remove sand, depending on certain well conditions. Most sand bailers consist of a cylinder and a piston with a ball check on top. The piston is manipulated up and down by up and down movement of the wireline, creating a suction. The cylinder housing the piston fills with sand or debris due to the vertical motion of the piston. After the load tube is filled, the bailer is pulled to the surface and emptied by removing the bottom sub.

It is advisable to run a leaded impression block before bailing when reaching the depth where a subsurface control is expected. The impression block will indicate the depth of the control and be marked with the impression of sand, debris, or the control fishing neck. An impression of sand or debris may require bailing. Chapter 4 contains additional information on sand and sand bailing operations.

Wireline Fishing

Fishing for wireline that has been lost in the hole is an operation that takes both skill and patience. The first step is to determine the depth to the top end of the line. This is of prime importance. If the end of the line is passed with a wireline spear and the line is grabbed very far below its top end, the line will ball up above the tools causing them to stick as the spear is pulled out of the hole.

Most of the time, wireline will stand straight in the tubing. As a rule of thumb, 0.082 or 0.092-in. wire will fall about 3 ft per 1,000 ft in $2^3/_8$-in. tubing, and about 5 ft per 1,000 ft. in $2^7/_8$-in. tubing. For example, assume a wireline parts at the surface as the operator is pulling a 2-in. safety valve from a nipple at 10,400 ft. If the line breaks at the truck, and the depth meter reading is 10,000 ft, the tools will fall back down hole to the 10,400-ft nipple. Assuming that the wireline remaining in the hole will drop 3 ft per 1,000 ft of depth, the end should be found in the tubing at about 430 ft. Fishing operations should begin at 400 ft. As a first step, the operator should run a combination wire finder and spear. The spear locates the end of the line and, at the same time, grabs it with sufficient "bite" to pull the fish to the surface.

If the combination tool fails to pull the fish (lost tools), a full-gage tool should be run to find the end of the line, and to ball up the line sufficiently below the tool to enable the operator to grab it with a 2-pronged spear. This spear may need to be jarred into the balled line with two or three strokes of the jars. This should cause the spear to "bite" the line, allowing it to be pulled to the surface.

Upon reaching the surface, the wireline valve must be closed on the line that has been fished out. The operator must make sure he has enough lubricator to hold the fishing tools and enough room for the spear to be several feet above the wireline valve. Pressure should then be bled from the lubricator, the union disconnected above the wireline valve, and enough line stripped through the valve to thread back through the lubricator. The end of the line can then be tied to the reel, and the fish pulled out of the hole.

At times the line may break during lengthy jarring operations, such as when attempting to pull a stuck choke. If the line breaks at the truck during such an operation and the line luckily hangs up on the stuffing box sheave, the operator can close the wireline valve on the line. If this occurs, there are two courses of action: First, a cutter bar (stem with blind box) can be dropped and the line cut at the wireline rope socket; second, a wireline snipper can be used. The snipper is similar in shape to a stem, but is slotted to accept the line. It actually rides the line down until the wireline rope socket is reached. This type of cutter usually crimps the line when making its cut at the socket. The crimp or bend will, in most cases, hold the cutter on the end of the line so it can be retrieved with the line. This is desirable when there is little or no pressure on the well. In wells with pressure, the line will blow out of the stuffing box when pulled within several hundred feet of the surface, because the weight of the cutter is not sufficient to overcome pressure across the stuffing box. The cutter would then strike the top of the lubricator with great force and might cause some damage. This should be taken into consideration before using this tool.

In cases where the line breaks at the surface, tools are stuck down hole, and the line falls down the hole (below the tubing flange), drop a cutter bar (stem and blind box) and wait a sufficient length of time for it to reach the wireline socket. The cutter will strike the socket with enough force to cut the line, or will crimp the line enough for it to break when pulled on. The operator may then run a spear and fish out the line. A pulling tool may then be run to fish out the cutter bar. It is advisable to run the cutter bar with a regular wireline socket on top.

When the line breaks at the surface and falls back into the well, but the end of the line stays lodged in the Christmas tree (which has a larger bore than the tubing), it is sometimes impossible to grab the end of the line. If this happens, a cutter bar must be dropped first, then a sidewall cutter run, and the cut made about 4 or 5 ft below the tubinghead flange. This short piece will fall down the tubing and can be fished out later. Next, the sidewall cutter is pulled from the hole and a suitable spear is run. If the cutter bar has reached the wireline socket, the line can be pulled. If the bar has not cut the line, enough line can be stripped through the wireline valve to enable the operator to drop a wireline snipper. Prior to dropping the snipper, a go-devil should be dropped. It will provide a cutting surface for the wireline snipper. After the line is pulled (measure it as it is pulled), a pulling tool is run to recover the snipper, go-devil, and cutting bar.

In some instances it may be necessary to fish out old line that has been left in the well for a considerable length of time. The line may be corroded and so brittle that it breaks easily requiring it to be fished out in short pieces. In this case, a good tool to try is an alligator grab. A magnetic tool may be used if extremely small pieces of wire have fallen on top of a subsurface control.

CHAPTER 3
SUBSURFACE EQUIPMENT

INTRODUCTION

Various types of subsurface completion, production control, and separation and commingling equipment associated with servicing by wireline are discussed in this chapter. Many applications of this equipment are also included. Because of their importance to safety and environmental protection, the Federal and State Regulatory Agencies have special requirements for some of these devices used in offshore operations. (See Page 49)

SUBSURFACE COMPLETION EQUIPMENT

Landing Nipples

A landing nipple is a short tubular nipple with tubing threads that is run in the well on the tubing string to a predetermined depth. Landing nipples are internally machined to receive a locking device which has a precision-machined profile that locks a production flow control device in the tubing string. The landing nipple is honed to receive high-pressure and high-temperature packing for sealing purposes. The packing is contained on the removable locking device. Landing nipples are furnished in all nominal tubing sizes, weights, and threads, with or without ports (ported nipples are discussed under Separation and Commingling Equipment), and are available in two basic types, selective and non-selective. Landing nipples are normally constructed of special alloy steels, stainless steels, or monel, with strength ratings equal to or greater than the tubing string.

A non-selective landing nipple (Fig. 3-1) is receiver for a locking device. As illustrated below, it utilizes a no-go principle (reduced I.D.) to locate the locking device in the landing nipple. This requires that the outside diameter of the locking device be slightly larger than the smallest internal diameter of the nipple.

A selective landing nipple is essentially full-opening. More than one can be run in a tubing string if all have the same internal dimensions (Fig. 3-2). All selective landing nipples utilize a mechanical principle for locating removable equipment.

Some advantages of using a landing nipple when completing a well are:

1. Plug well from above, below, or both directions.
2. Test tubing string.
3. Set tubing safety valve.
4. Set bottom-hole regulator.
5. Set bottom-hole choke.
6. Land slim-hole packer.
7. Hang bottom-hole pressure gage with or without packoff.
8. Hang sand screen.
9. Locate and land pump with or without holddown.
10. Set standing valve.
11. Hang extension pipe.
12. Set nipple stop.
13. Reference point for checking measurements.
14. Set hydraulic packers.
15. Set injection safety valve.

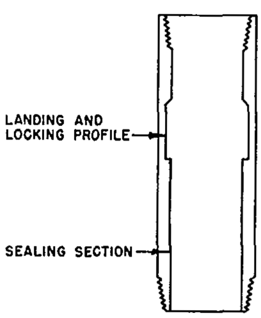

Fig. 3-1 — Non-selective landing nipples

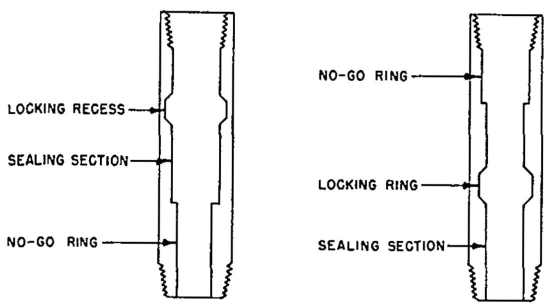

Fig. 3-2 — Selective landing nipple

Removable Locking Devices

Removable locking devices lock and seal in the tubing string. Various subsurface production controls may be attached to these devices. There are two basic types of removable locking devices.

Landing-nipple locking devices locate, lock, and seal in a landing nipple. This type of lock (Fig. 3-3) is considered superior to other types in that it:

1. Provides a positive lock; the locking dogs are mechanically wedged out into the machined locking recess provided in the landing nipple.
2. Contains high pressure and high temperature sealing rings that are positioned in the internally machined and honed portion of the landing nipple.
3. Is rated normally at 10,000 psi differential.
4. Locks and seals pressure differential from either direction, depending upon production control attached.
5. Is more easily set and retrieved by wireline because of the internal/external dimensions.

Tubing ID locking devices are designed to lock and pack off removable subsurface controls in tubing strings which have not been equipped with landing nipples. This type locking device uses cup or rubber element type seals which pack off against the tubing wall. Pressure-differential ratings are considerably less than those of the landing-nipple locking device, and the effectiveness of the seal is greatly dependent upon the condition of the tubing wall. There are two basic types of tubing ID locking devices.

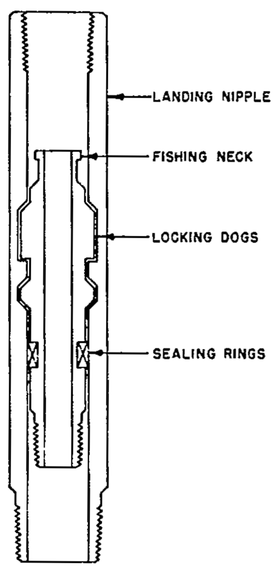

Fig. 3-3 — Landing-nipple locking device

The collar-lock (Fig. 3-4) locks in the collar recesses of collared tubing strings and is designed to hold pressure differential from either direction depending upon the attached control. The slip-type lock (Fig. 3-5) consists of three slips mounted on a tapered body that wedges the slips outward, effecting a lock against the tubing wall. Slip-type locks are designed to hold pressure from one direction only, and are limited in pressure differential. It is possible that slips could damage the coating in wells equipped with coated tubing.

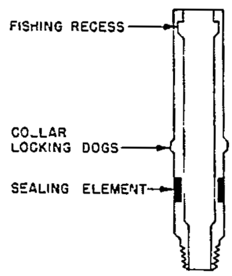

Fig. 3-4 — Collar lock

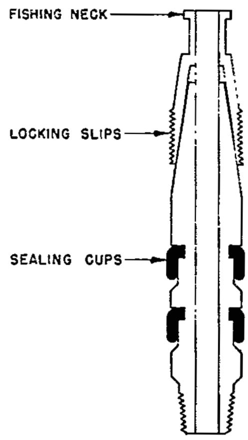

Fig. 3-5 — Slip-type lock

Polished Nipples

A polished nipple is a short tubular nipple with tubing threads. It is constructed of the same materials as the landing nipple. A polished nipple does not contain locking recesses, but is machined and internally honed to receive a sealing section. Polished nipples may be used in conjunction with landing nipples, sliding sleeves, blast joints, and other completion equipment. For example, in Fig. 3-6 a landing nipple is attached to the top of a blast joint and a polished nipple is attached to the bottom of the same blast joint. The landing nipple receives the removable locking and sealing device for an attached spacer pipe. The lower sealing section is positioned in the polished nipple. The removable assembly permits the isolation of this blast joint in the event of communication caused by erosion.

Flow Couplings

A flow coupling is tubular in construction, normally 2 to 4 ft long, and usually made of high-grade alloy steel (Fig. 3-7). The flow coupling is machined with coupling-size outside dimensions and full tubing inside dimensions which furnish a greater wall thickness as protection against possible internal erosion and corrosion. Flow couplings are positioned immediately above and, on some occasions, below a landing nipple designed to receive a production control such as a tubing safety valve, bottom-hole regulator, bottom-hole choke, etc.

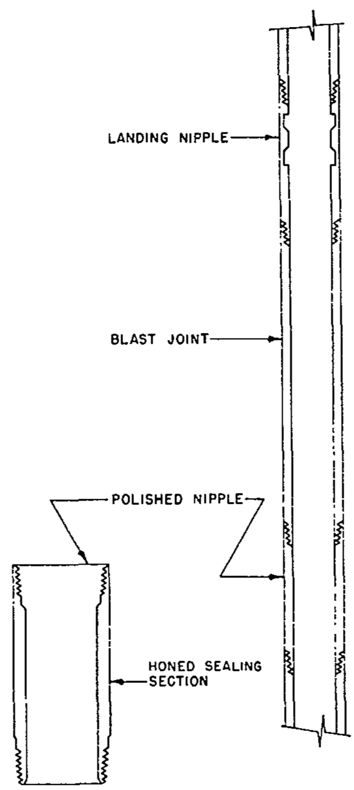

Fig. 3-6 — Polished nipple blast joint, landing nipple

Blast Nipples And Blast Joints

Blast nipples are discussed in this section because of the important role they play in a planned completion utilizing other wireline completion equipment. They are constructed of various types of materials, with external and internal dimensions similar to those of flow couplings.

Blast joints are usually manufactured in lengths of 10, 20 and 30 ft, and are run in the tubing string and positioned opposite perforated intervals in multiple completions. This gives added protection against erosion resulting from jetting actions of producing perforations.

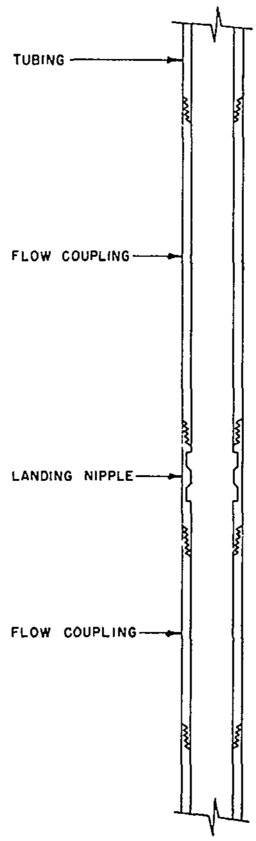

Fig. 3-7 — Flow coupling

SUBSURFACE PRODUCTION EQUIPMENT

Retrievable subsurface production controls are run in the tubing string under pressure by wireline and locked and sealed there to perform particular functions. These functions aid in providing safety, increased environmental protection, and additional savings in remedial operation costs. This work is accomplished without the use of conventional workover procedures and without disturbing the Christmas Tree or packer settings.

Equalizing Subs

Equalizing subs (Fig. 3-8) provide a means of equalizing differential pressures across subsurface controls prior to reopening or retrieving them from the tubing string. They are usually run between the locking device and the production control. There are two basic types of equalizing subs. One type utilizes an equalizing prong attached to a pulling tool. The prong shears a knockout plug, opens a spring-loaded valve which protrudes into the bore of the sub, or shears and forces a pinned sleeve valve with O-rings off seat. Another type requires retrieving an equalizing prong that is attached to the

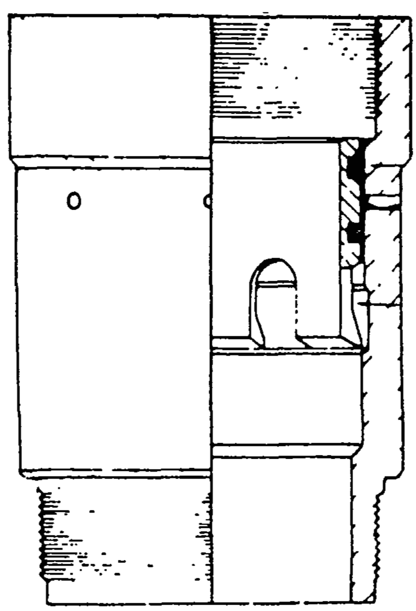

Fig. 3-8 — Equalizing sub

locking device by a shear pin. All production controls that are subjected to pressure differentials should be run with equalizing devices. Under situations that may permit sand, scale, and other debris to settle on top of a tubing plug, the retrievable prong-type equalizing device is generally recommended.

Retrievable Tubing Plugs

There are three basic types of retrievable tubing plugs which are set in landing nipples or tubing strings and plug the tubing pressure from above, below, or in both directions.

The tool that plugs from below (Fig. 3-9) is attached directly to an equalizing sub which is attached to a locking device. It consists of a spring-loaded plug bean assembly which seats on a ground metal seat provided in the equalizing sub. A variation of this type seat includes a rubber seal in addition to a metal seat. This plugging device is designed so that it can be pumped through from above. It is important that, when installing this type of plug in fluid or running through a series of landing nipples or setting in a landing nipple, a fluid bypass be provided. Fluid bypass eliminates the possibility of a fluid lock and is provided by the use of a running prong.

The circulating plug (Fig. 3-10) holds pressure only from above and may be flowed through. Its construction has several variations, such as a ball and seat, valve and seal, or rubber-type check valve.

The third type plug (Fig. 3-11) seals in both directions and is used mostly for separating zones in selective-type completions. It is provided with a fluid bypass for running and utilizes a retrievable prong-type equalizing feature. Another type consists of spring-loaded double-ball check with knockout-type or sliding-sleeve type equalizing features.

Table 3-1 lists a few applications of the use of tubing plugs in landing nipples.

Bottom-Hole Chokes

Bottom-hole chokes (Fig. 3-12) are usually anchored in the lower section of the tubing and provide the following applications:

1. Reduction or prevention of freezing of controls by lowering the point of the pressure drop to the lower portion of the well.
2. Reduction of water encroachment through the stabilization of bottom hole pressures.
3. Reduction of gas-oil ratios under certain conditions.
4. Reduced production when desirable.

Bottom-Hole Regulators

A bottom-hole regulator (Fig. 3-13) is essentially a bottom-hole choke and performs similar functions. In operation, the regulator is a normally closed assembly that consists of a valve and a spring-loaded seat. When the predetermined pressure differential across the tool is reached, the spring moves upward, unseating the valve and allowing the well to flow at this reduced pressure. Pressure drop can be adjusted by adjusting the spring tension in the regulator. If necessary, the well can

TABLE 3-1
APPLICATIONS FOR TUBING PLUGS AND TYPE RECOMMENDED

	Plug from Above	Plug from Below	Plug both Directions
1. Repair surface equipment		X	X
2. Test tubing by bleeding down		X	X
3. Test tubing by pressuring up	X		
4. Snubbing tubing in or out of well		X	
5. Set hydraulic packer	X		
6. Circulate above with fluids	X		X
7. Zone separation in selective completions			X
8. Fracturing selective completions	X		X
9. Kill well		X	
10. Move rig on or off location		X	X
11. Use as standing valve	X		
12. Packer test			X
13. Acidizing on selective completions	X		X
14. Wellhead plugging on completions		X	X
15. Wellhead plugging on remedial work		X	X

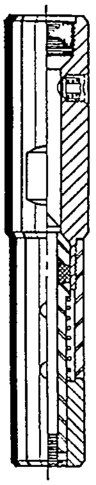

Fig. 3-9 — Plug from below

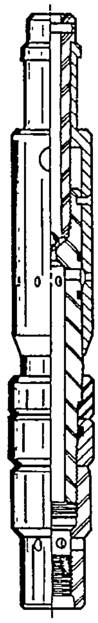

Fig. 3-10 — Circulating plug

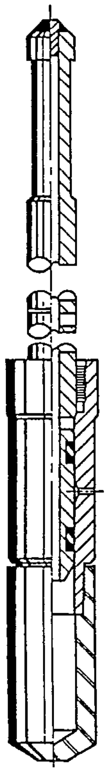

Fig. 3-11 — Equalizing prong and valve

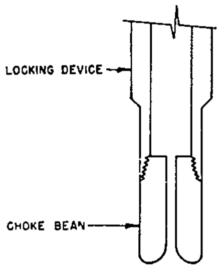

Fig. 3-12— Bottom-hole choke

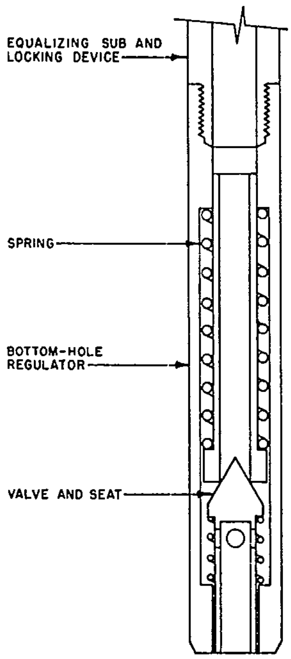

Fig. 3-13 — Bottom-hole regulator

be killed by pumping through this tool. Some applications provided by the bottom-hole regulator are:

1. Helps to eliminate need for surface heaters.
2. Maintains safe and workable surface flowing pressures.
3. Decreases wellhead and flowline hydrate formation.
4. Can be utilized for stage-plugging wells not equipped with landing nipples and with shut-in pressures in excess of 1,500 psi where slip-type locks are used.

Safety Valves

Safety valves are designed to automatically shut in the flow of a well in the event surface controls fail or surface equipment becomes damaged. There are two basic types of subsurface safety valves. They are classified according to the location from which they are controlled — surface or subsurface (Fig. 3-14). Safety valves installed in offshore wells located on the Outer Continental Shelf (OCS) must comply with regulations promulgated by the United States Minerals Management Service (MMS), based on guidelines in API Spec 14A, RP14B, and Manual 14B, and included in 30 CFR, Part 250, Subpart H. (See Page 49)

The surface controlled subsurface safety valve (SCSSV) is a device which shuts off well flow in response to a manual or automatic signal from a surface source. The valves are either tubing retrievable or wireline retrievable (Fig. 3-14). Either type is accepted by the MMS, and each type offers distinct advantages and disadvantages. The method of control may differ, but the results are the same. A certain amount of pressure is applied at the control source to keep the valve open. When this pressure is lost, the valve will shut. The three methods of control are: Control line (the most common), concentric control, and casing control. Table 3-2 lists some of the advantages and disadvantages of each method.

The control line method is used more than any other. A $^1/_4$ inch stainless steel control line is attached to the outside of the tubing string and installed when the tubing is installed. In most types of installation, the pressure on the control line must exceed the wellhead tubing pressure by 600 psi or more. Control line pressure depends on the manufacturer of the valve and the valve design. Depending on the wellhead pressure, it may be necessary to keep as much as 4000 to 5000 psi on the control line to keep the valve open.

Most of the valves built today are hydraulically operated using a shoulder area to pump open the sleeve. This sleeve operates a ball or flapper which sets as a sealing medium shutting off well flow. The valves are run in the tubing string or in a nipple assembly in the tubing string. The nipple assembly will accept a wireline retrievable safety valve.

Casing and tubing sizes often dictate which type valve to use. Besides the control line method, other types of control are concentric control and casing control. All these installations are discussed in more detail in API RP 14B: *Recommended Practice for Design, Installation and Operation of Subsurface Safety Valve Systems.*

A subsurface controlled subsurface safety valve (SSCSV) is a device that shuts off well flow in response to a signal from the at-depth environment. Two types are in use: the pressure operated valve and the differential valve.

There are two different working principles involved in this type of safety valve. The pressure operated valve employs a dome and a bellows, and the differential valve is controlled with a flow bean and spring tension. Both types are shown in Fig. 3-15. Both valves are wireline retrievable, and both are controlled by existing well flow.

The pressure operated SSCSV senses pressure, using a dome and bellows for operation. The amount of pressure in the dome depends on the desired closing pressure. When the tubing pressure drops below the pressure in the dome, the disk snaps shut. Due to the large flow area, this valve allows production of large volumes of fluid or gas and still maintains safe well control. The valve is put back in service after closure without being removed from the tubing. The disk returns to the open position once the valve is equalized with a pressure greater than or equal to that below the closed valve. The valve is tested for leakage while installed in the well. When being pulled for periodic inspection, the valve is tested for proper settings and leakage in a handy test rack. For offshore wells in the OCS, the valves should be tested as per the requirements of API RP 14B.

The differential type subsurface controlled subsurface safety valve senses pressure drop across a flow bean. There are several variations of the differential type SSCSV. Although they employ different sealing devices, such as a flapper or ball, they all are controlled with a flow bean and spring tension. The valve is often referred to as a velocity type valve and is normally an open valve. The flow is directed through the bottom of the valve, through a flow bean, and up the inside of the bean extension. The flow bean is attached to the lower seat and governs the amount of fluid and gas passed through it, acting much like a surface choke. The spring pushes down on the flow bean and lower seat, holding the valve open. When the differential pressure across the flow bean reaches the closing differential, the valve closes. The valve may be tested by flowing the well at successively increasing rates until the valve closes. Testing of valves in offshore wells in OCS waters should be as per the requirements of API RP 14B.

Input or injection safety valves are usually used in injection wells to provide protection from backward flow in the event of surface equipment failure. This valve is a simple, spring-loaded valve and seat mechanism using a ground metal seat (Fig. 3-16). The injection pressure forces the valve open for fluid and gas passage. If injected flow becomes static or flow direction reverses, the spring tension and/or flow pressure forces the valve to close and shut in the well.

In general, tubing safety valves are used for protection against uncontrolled flow in the event of surface control failure or damage. Some applications are:

1. Locations subject to damage by boat and barge traffic.
2. Isolated locations, both land and marine, which are costly and time-consuming to supervise.
3. Compliance with various state and federal laws.
4. Wells in or near townsites and heavily traveled roads.

Standing Valves and Tubing Stops

Standing valves (Fig. 3-17) are used mostly in intermitting gaslift wells to contain fluid in the tubing string during an injection cycle. Standing valves can be set in landing nipples, pump seating nipples, and on tubing ID locking devices. In construction, a standing valve is equipped with a sealing section and a ball-and-seat or valve-and-seat type check allowing upward flow of fluid and checking or preventing downward

TABLE 3-2
ADVANTAGES AND DISADVANTAGES OF VARIOUS CONTROL METHODS

Control Method	Advantages	Disadvantages
Individual Control Line(s)	Little additional clearance required. Minimum control fluid volume.	Small line subject to damage. Precaution required to avoid plugging of control line.
Concentric Control	Mechanically strong. Adaptable to tubingless completions. Not very susceptible to plugging.	Large volume of control fluid and special clearances required. Not always feasible for multiple completions. High initial cost.
Casing Control	Mechanically strong. Little additional clearance required. Low initial cost. Not very susceptible to plugging.	Large volume of control fluid required. Precaution required to avoid connection leaks. Requires control pressure on casing.

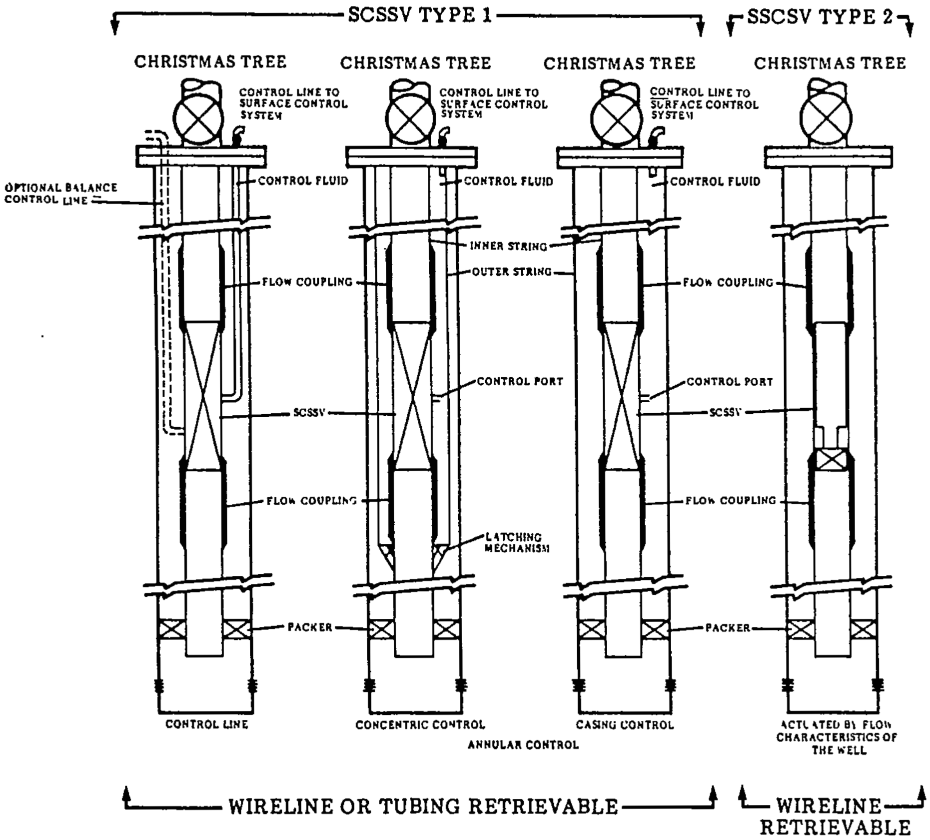

Fig. 3-14 — Types of safety valves

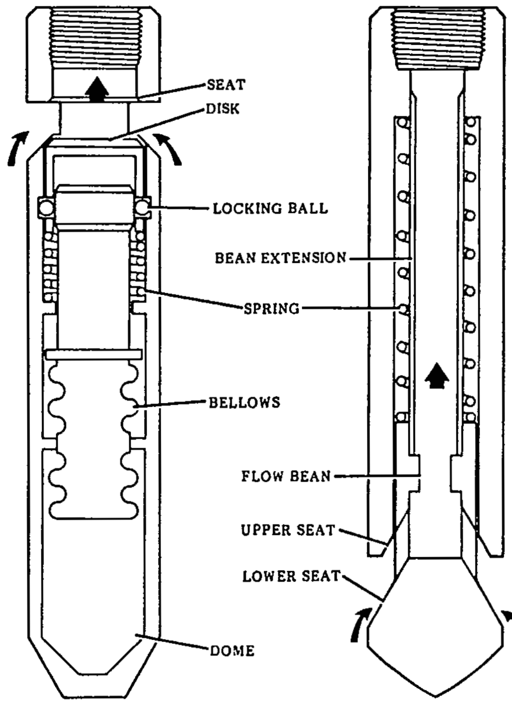

Fig. 3-15 — Types of subsurface controlled subsurface safety vaules

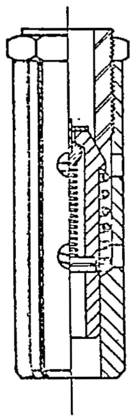

Fig. 3-16 — Input safety valve

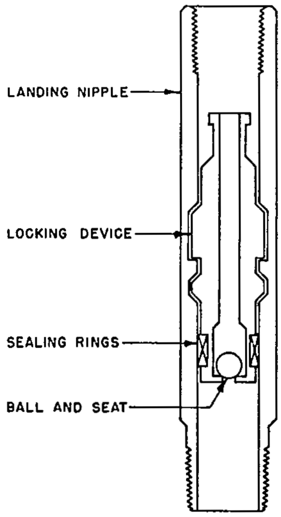

Fig. 3-17 — Standing valve

flow. Most standing valves are equipped with equalizing features for retrieving and are available with or without holddowns.

There are three basic types of tubing stops: collar stops which lock in tubing collar recesses; slip-type stops which lock against tubing wall ID; and landing-nipple stops which lock in landing nipples, primarily used in internal-flush tubing.

Removable tubing stops are placed in the tubing string to confine any wireline tools dropped during wireline operations. Confining dropped tools to the tubing string eliminates more difficult fishing operations in open hole, casing, liners, and top of packers. Tubing stops do not effect a seal in the tubing string and provide adequate flow area through and around the tool. Some of the applications of tubing stops are during the following operations:

1. Swabbing
2. Bottom-hole pressure surveys
3. Caliper surveys
4. Retrievable gas-lift operations
5. Paraffin cutting
6. Plunger installations
7. Tubing packoff installations
8. Tubing perforating
9. Circulating plugs
10. Hanging bottom-hole pressure gages
11. Corrosion-inhibiting operations

SEPARATION AND COMMINGLING EQUIPMENT

Separation and commingling equipment is run on the tubing string to provide a method of selectively commingling between the tubing and the tubing-casing annulus by use of wire line. This type of equipment is of particular advantage in multi-packer installations, in that it allows access to alternate zones using wireline rather than costly workover operations, without disturbing tubing and packer settings or killing formations. There are three basic types of separation and commingling equipment.

Ported Nipples and Assemblies

A ported nipple (Fig. 3-18) is essentially a landing nipple that contains ports and internally honed sections above and below the ports which receive packing sections of a subsurface control. Ported nipples have coupled outside diameters and have the advantage that the subsurface commingling device may be removed from the tubing string to repair or alter flow courses. In multi-zone completions utilizing side-port equipment, the zones are commingled during service operations and offer a restriction with a flow-control in place in order to prevent commingling. Therefore, if more than one ported-nipple assembly is installed in the same tubing string, it is necessary to remove the upper control to retrieve the lower. Ported nipples generally receive different types of production controls, such as the following:

1. A side-door choke (Fig. 3-19) locks in a ported-nipple assembly and packs off above and below the ports of the nipple. This isolates the annular area and allows the lower or tubing zone to flow through the assembly.
2. A separation tool (Fig. 3-20) also lands in a ported-nipple assembly and seals off below the ports, blanking off the tubing zone to flow through the assembly.

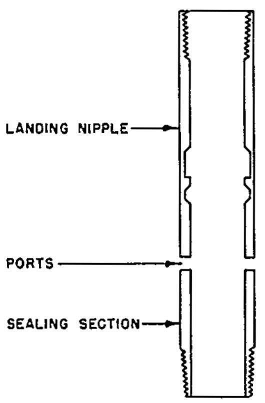

Fig. 3-18 — Ported nipple

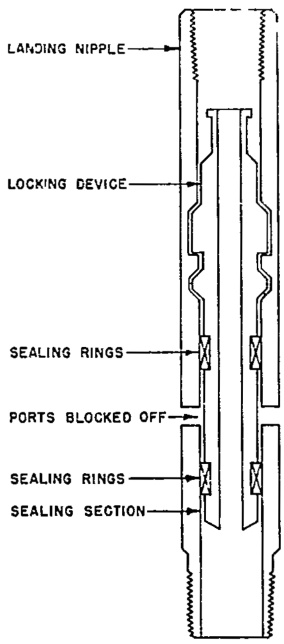

Fig. 3-19 — Side-door choke

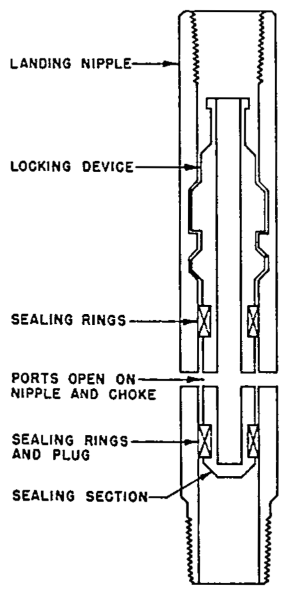

Fig. 3-20 — Separation tool

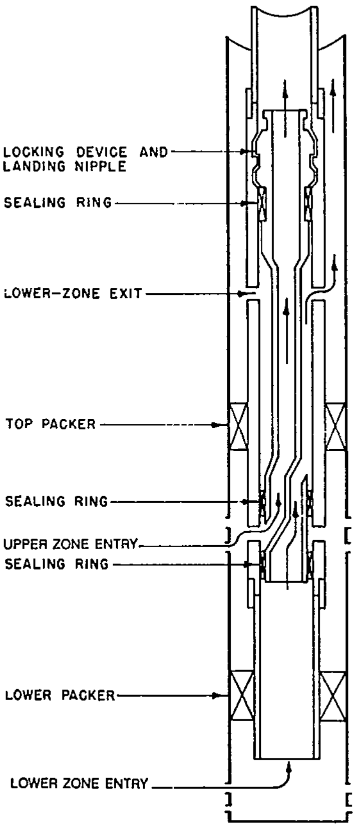

Fig. 3-21 — Crossover choke

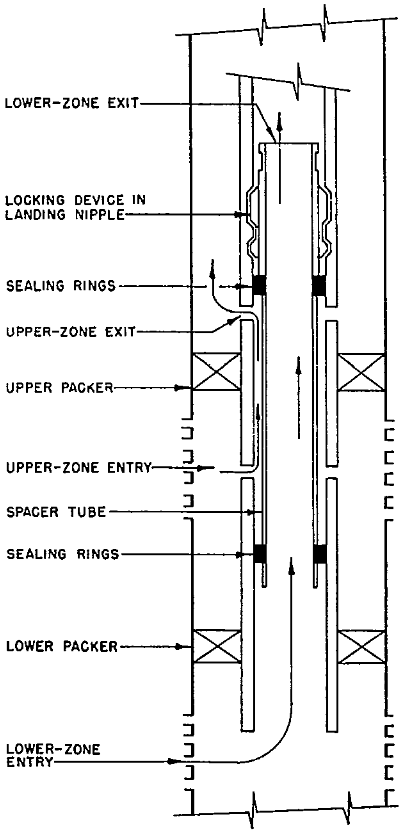

Fig. 3-22 — Straight flow choke

3. The crossover assembly (Fig. 3-21) lands in the same type ported nipple as the side-door choke and separation tool. The crossover assembly is used in a two-packer installation. An additional ported nipple is placed beneath the top packer, whereas the side-door nipple assembly is placed immediately above the packer. A crossover choke spans from the upper landing nipple to the lower ported nipple, sealing off in such a way that the upper zone or zone beneath the top packer flows through the tubing while the lower zone or zone from beneath the lower packer flows up the annulus.

4. The flow course of the two zones may be altered by installing a "straight-flow choke" (Fig. 3-22). By removing the crossover choke and replacing it with a straight-flow choke, the upper zone or zone beneath the top packer flows up the annulus while the lower zone or zone beneath the lower packer flows up the tubing.

Retrievable Valve Mandrels (Side Pocket Mandrels)

Retrievable valve mandrels [Fig. 3-23 (A) and (B)] were initially designed to receive retrievable gas-lift equipment. However, since this mandrel receives retrievable locks and sealing devices, it has been used in the same manner as ported nipples and sliding sleeves. This mandrel offers advantages similar to side-port equipment, in that the retrievable flow-control devices may be retrieved by wire line, and advantages similar to a sliding sleeve in that it has full tubing internal dimensions with a flow device positioned in the side pocket. Because of the full internal bore provided, it is necessary that the outside diameter be larger than the tubing coupling at the side-pocket section.

Gas-lift valves and subsurface control flow devices may be selectively set and retrieved from the mandrel through use of a kick-over tool that positions the equipment into the side pocket of the mandrel. With a flow device in this offset position, the possibility of sand or tubing debris falling on top of the flow device is reduced. Oval-shaped mandrels [Fig. 3-23 (B)] are used in multiple-string completions and are available in various tubing sizes and threads. A variation of the retrievable mandrel utilizes a no-go type landing nipple incorporated into the center of the mandrel for locking and sealing additional subsurface controls.

Sliding Sleeves

Sliding Sleeves (Fig. 3-24) are run on the tubing string and are essentially full-opening devices with an inner sleeve which can be opened or closed by wireline methods to provide commingling with the tubing-casing annulus. Sleeves are tubular in construction with tubing coupling OD and full-opening internal dimensions. There is a slotted inner sleeve manufactured of non-corrosive materials and equipped with shifting profiles or shoulders. These profiles or shoulders provide a means for the wireline shifting tool to engage the inner sleeve during the opening or closing operation. The outer ported or slotted housing contains a sealing section on most types, while other types place the sealing elements on the movable inner sleeve. Some sleeves are available with equalizing ports or slots and all types of sleeves use either collets or snap-ring-type locking arrangements. Sleeves are available in all nominal tubing sizes, weights, and threads, and are constructed to withstand tensile strengths equal to or greater than the tubing string. It is possible to run an unlimited number of sleeves in a tubing string and selectively operate them.

A variation of the sliding sleeve (Fig. 3-25) incorporates a landing-nipple profile in the upper section and is equipped with a smooth sealing bore in both the upper and lower sections. This provides an additional landing nipple in the tubing string for side-door or separation equipment. This type sleeve is available to receive locking devices which utilize no-go principles and to receive selective-type locking devices.

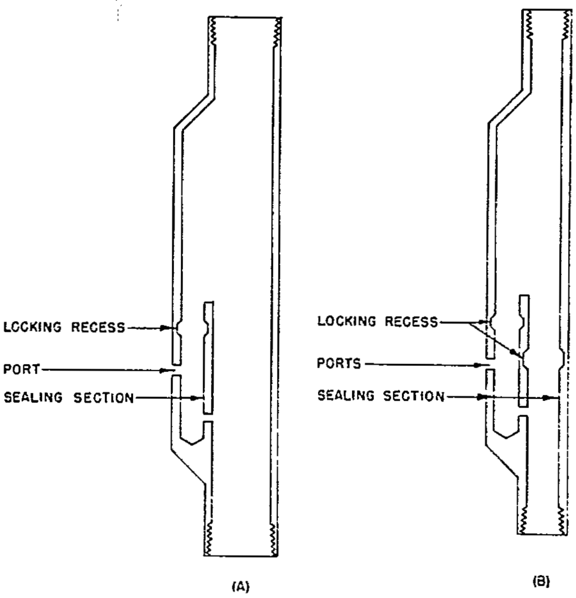

Fig. 3-23 — Retrievable valve mandrels

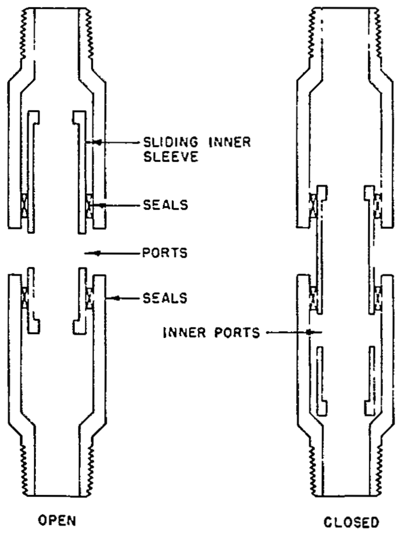

Fig. 3-24 — Sliding sleeve

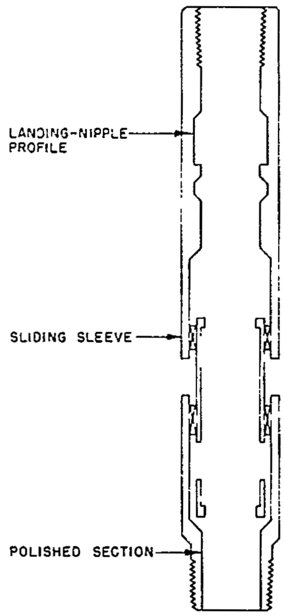

Fig. 3-25 — Sliding-sleeve — nipple combination

PACKOFFS

Packoffs (Fig. 3-26) are designed to be run and pulled with a wire line. They are used to straddle and pack off a hole or holes that have developed in a tubing string, thus permitting continued production of the well without pulling tubing. The holes may result from erosion opposite perforations in upper zones of multiple completions, from corrosion at any point in the tubing string, or may be intentional perforations with a tubing perforator. In construction, a tubing ID packoff consists of two sections of removable sealing elements that are connected by a space pipe. The elements are spaced to straddle a hole and are designed to be mechanically expanded against the tubing wall, sealing pressures from both directions. Slip-type stop incorporated into the packoff or run separately is used on top to act as an upper holddown. Packoffs and tubing stops are equipped with large internal dimensions for straight-through flow.

Gas Lift Packoffs

If a well needs to be put on gas lift but a workover is not economically advisable, this may be accomplished entirely by wireline methods.

After the installation has been calculated, a tubing stop is set at the depth of the lowermost valve. The tubing can be perforated by wireline tools just above this stop. A packoff assembly is made by containing a concentric gas-lift valve between sealing elements and is landed on the tubing stop thus sealing above and below the perforated hole (Fig. 3-27). Another tubing stop may then be set above this assembly, but this is not always required.

Afterward, each successive gas-lift valve is installed in the same manner farther up the tubing string. All can be retrieved for servicing or working lower in the string if necessary.

The injection gas then enters the tubing from the annulus through the perforated hole, into the gas-lift valve, then on up the tubing string.

Some gas-lift packoffs offer bores large enough to run bottom-hole pressure tools.

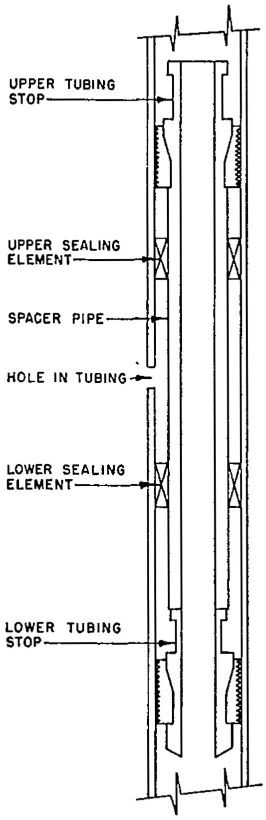

Fig. 3-26 — Packoff

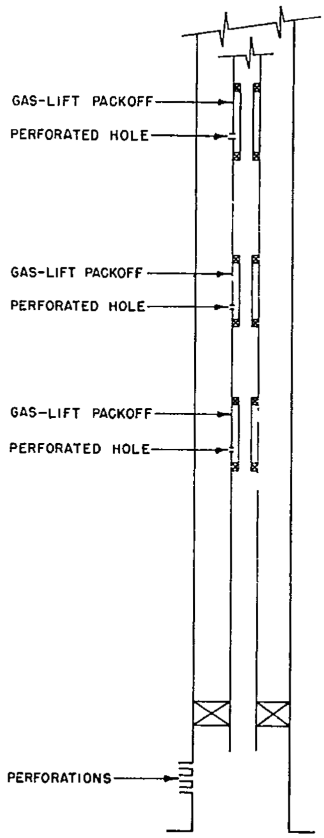

Fig. 3-27 — Well equipped with wireline gas lift packoffs

TYPICAL ILLUSTRATIONS UTILIZING SUBSURFACE EQUIPMENT

Single-String — Tubing-Annulus Dual

Fig. 3-28 shows a simple tubing-casing dual. By plugging below the ports of the commingling device, the upper zone is admitted into the tubing string for production or to run bottom-hole pressure survey, fracture, acidize, or treat in some other manner.

This arrangement also allows the lower zone to unload the upper zone, flow both zones together to cleanup, displace fluids on completion or later remedial work, swab in upper zone, and kill the upper zone through the tubing.

Two-zone — Two-string Dual Installation

Fig. 3-29 shows a typical two-zone — two-string dual in a slim-hole completion. This well was originally a single-zone tubingless completion by virtue of a string of $2^7/_8$-in. tubing cemented in place.

An upper zone was perforated and $1^1/_4$-in. tubing run and set in a packer. This $1^1/_4$-in. string uses wireline completion equipment in the same manner as conventional completions.

Two-zone — Two-packer Single String — Single Alternate Completion

Fig. 3-30 illustrates a completion for the following wireline packer-leakage tests.

Lower Packer Test from Below

1. A bottom-hole-pressure gage, shock absorber, and two-way plug are attached and landed in the lower landing nipple. This blanks off the lower zone with the gage exposed to bottom-hole pressure.

2. The commingling device is opened to the upper zone, thus producing that zone up the tubing string. The gage then records any pressure changes on the lower zone thus testing the lower packer from below.

Upper Packer Test from Below and Lower Packer Test from Above

1. After the foregoing test, retrieve the plug and gage and set an upside-down crossover choke with bottom-hole-pressure gage held in a bull-plugged tube in the upper nipple. This assembly seals in the landing nipple and the polished nipple — with the commingling device opened — thus admitting the upper-zone pressure into the choke and down into the tube containing the bottom-hole-pressure gage and is trapped there.

2. Flow the lower zone, whose flow course would be up and around the crossover choke on up the tubing string. The gage then records any pressure change on the upper zone while the lower zone flows up the tubing. This tests

the upper packer from below, and the lower packer from above. A pen recorder is placed on the annulus at the surface to record pressure changes on the upper packer from above.

3. Retrieve choke and gage, close commingling device, and resume production.

Two-zone — Two-packer — Two-string Dual Installations

This well design [Fig. 3-31 (A)] is a typical dual installation. The landing nipple is positioned on bottom primarily for testing, and later for production controls. The long-string commingling device is used on completion to displace down the long string and up the short string once the packers are set and tested. This design is also used to kill a well with tree on. The short-string commingling device is used to displace annular fluid after packers are set, tested and the tree is on.

The well design shown in Fig. 3-31 (B) is similar to that shown in Fig. 3-31 (A) with the added features of the landing nipple and polished nipple attached to the blast nipple. This will receive a retrievable packoff in the event the joint cuts out. Another difference is that a landing nipple and flow couplings are placed up the two tubing strings to receive tubing safety valves, regulators, plugs, etc.

The well design shown in Fig. 3-31 (C) is similar to that in Fig. 3-31 (A), except that the two lower nipples are the no-go type. The bottom longstring nipple is a part of the permanent packer attached by a pup joint.

The short-string bottom nipple is attached to the bottom of the dual packer. This provides the ability to plug in the lower nipples and retrieve either string without killing the other zone.

Tubing Seal Dividers and Tubing Seal Extensions

With the advent of massive fracturing jobs on limestone and sandstone formations, a new completion system was needed to protect the formation in workover operations, since fluid pumped into the fractured formation may create permanent damage and loss of production. The following workover methods were utilized and are used in newer limestone and sandstone formation wells at this time:

> The Tubing Seal Divider has a nipple profile cut in the top stringer of a packer extending above the packer body. It has a polished packing surface and J-slot latch plugs on the outside. (Fig. 3-32)

Below the packer is a cut-off pup joint and another landing nipple (usually a No-Go nipple). The tubing has a seal assembly on the bottom with packing and the J-slot profile.

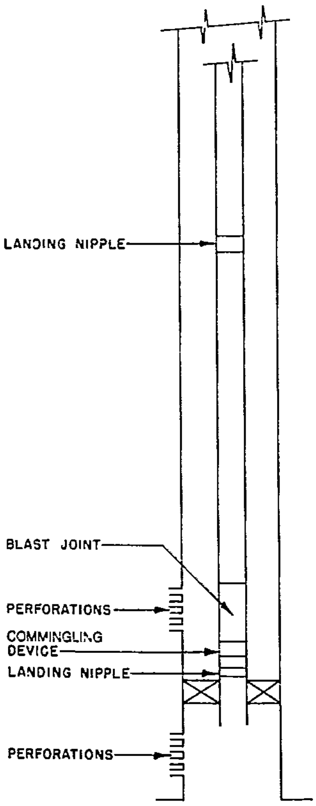

Fig. 3-28 — Single-string — tubing-annulus dual completion

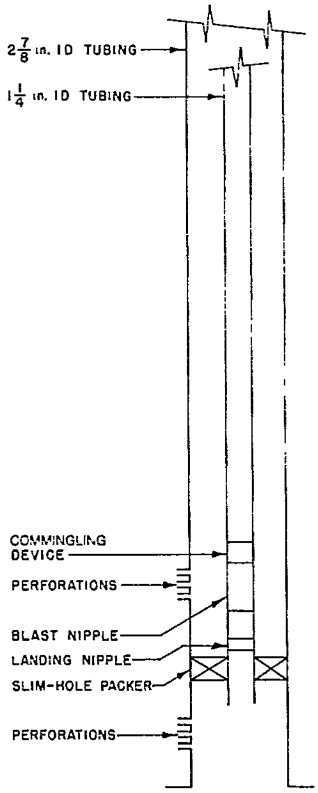

Fig. 3-29 — Two-zone — two-string completion

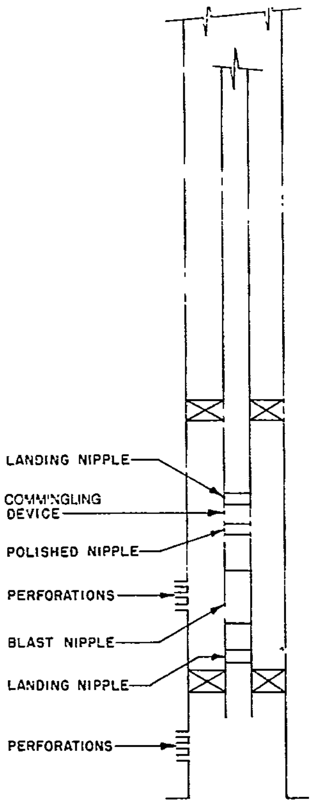

Fig. 3-30 — Two-zone — two-packer single string single altenate completion

With this device a blanking plug can be set in the nipple profile, and when the pressure is bled off, the hole can be loaded above the packer and the tubing pulled from the well without damaging the formation. Clean fluid can be circulated around the fishing neck on the plug through the tubing prior to relatching the J-slot. Then the plug can be retrieved by wireline.

The second method uses a tubing seal extension. With this system, a large bore extension, usually 10 to 20 feet long, is screwed onto the packer and then swagged down to tubing size. Below this is run a pup joint, landing nipple, another pup joint and a No-Go nipple (Fig. 3-33). A plug can be set in the nipple and the pressure bled down and the tubing removed without damaging the formation. Due to the long seal bore extension, multiple sets of packing segments can be run on the seals so that the tubing can expand and contract, or "breathe", without unseating the packer. This eliminates a packer hold down, and setting excessive weight on the packer.

The pup joints were placed between the nipples for cut off joints in case the plugs could not be pulled. Sand and trash will naturally collect in the pocket under the packer. To facilitate pulling the plug, the top nipple was replaced with a sliding sleeve. The sleeve has a nipple profile in it and can be used as a nipple. If there is trash on the bottom plug, the sleeve can be opened and the well produced around the plug until the trash is clean. Usually one or two runs with the bailer is all that is necessary to finish cleaning the top of the plug. Then it can be retrieved.

This system is also useful when the bottom nipple is used to hang bottom hole pressure gages and the top nipple is used to set a plug after the pressure gages are hung.

Both of these methods are very effective and are used on most limestone and sandstone formation wells.

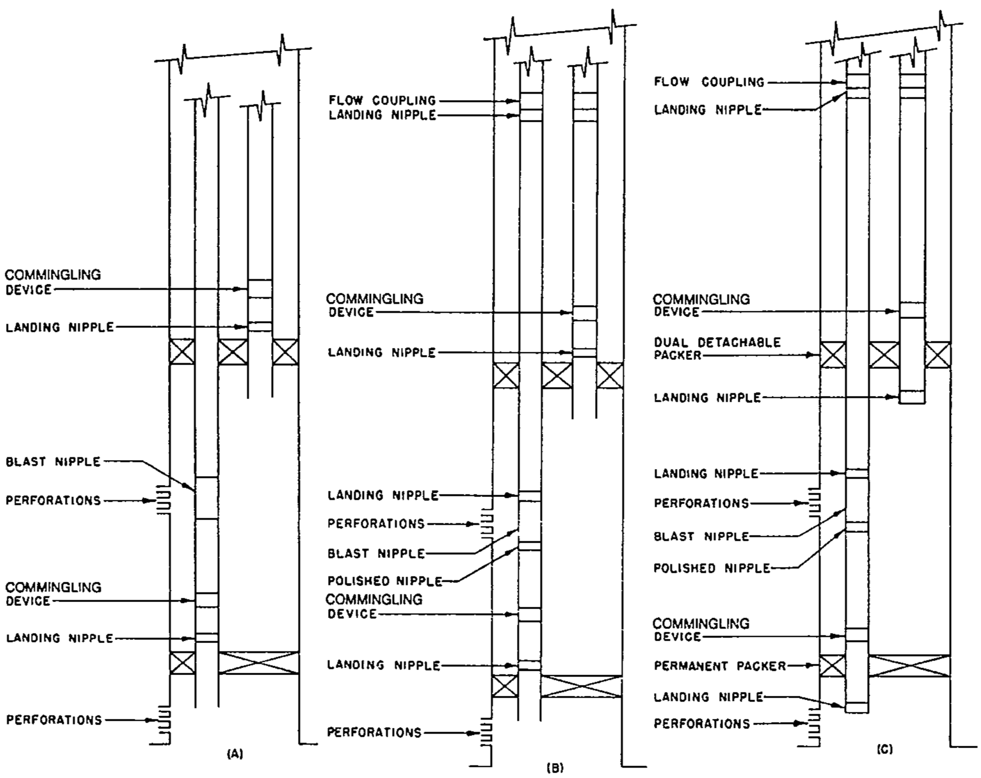

Fig. 3-31 — Two-zone — two-packer — two-string dual completions

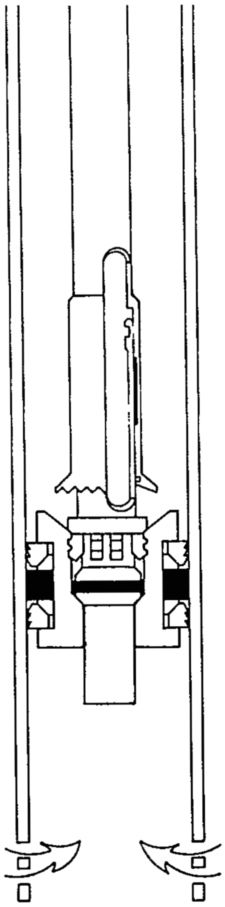

Fig. 3-32 — Tubing seal divider

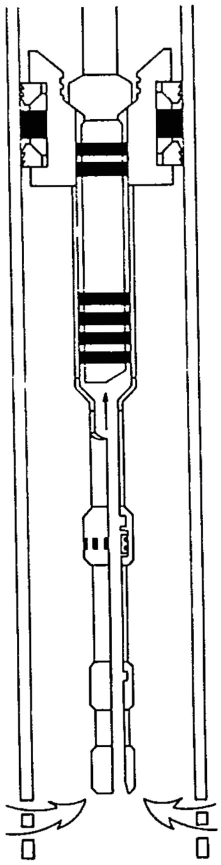

Fig. 3-33 — Tubing seal extension

CHAPTER 4
WIRELINE OPERATIONS
(INCLUDING OFFSHORE PROCEDURES)

INTRODUCTION

The purpose of this chapter is to describe the actual function of the various tools used in subsurface wireline operations. Before any actual wireline work is performed, however, certain information and preplanning of the job should be done by both the wireline operator and the well operator.

WIRELINE SAFETY

The most important part of any wireline operation is the practice of safe work habits. Safety must always be of prime importance to the wireline operator. He should act in a manner, and require all his personnel to act in a manner, which should foster a safe working environment for the protection of both personnel and the well. Although safety recommendations are included throughout this manual, a complete list of safe practices would be too extensive to cover. Good judgment and common sense should always play a part in any operational procedure. Because of the high toxicity of hydrogen sulfide (H_2S), the following special safety recommendations are included for wireline operations on wells expected to produce H_2S (sour gas):

1. Place the wireline unit upwind from the wellhead. This can be determined by noting the position of the required windsock.
2. Check equipment for proper breathing apparatus and resuscitator.
3. Advise proper authorities before entering and departing the location.
4. Throughout the operation, all crew members must be within sight of an observer (not necessarily a wireline specialist). The observer's duties are to watch the crew members and give the alarm if any unusual behavior occurs.
5. Make sure all personnel understand the actions to be taken in an emergency, especially in case evacuation is required. Hold a meeting before the job starts, if possible.
6. Only H_2S rated equipment should be used.
7. The wireline should be protected. One method is described under "Special Problems" in this chapter.
8. H_2S detection and alarm equipment should be properly selected and located. Location should be pointed out to all personnel.
9. Breathing apparatus must be worn during all operations where personnel may be in contact with well effluents.

RECOMMENDED OPERATIONAL PROCEDURES

Land Locations, Wireline Truck or Trailer
(Refer to Fig. 1-1)

1. Clear the area around the wellhead of any hazardous objects that can be moved.
2. Note the shut-in well pressure and inquire as to whether or not it is the maximum shut-in pressure. Be sure that the surface equipment on location is of sufficient working pressure to withstand the maximum anticipated wellhead pressure.
3. Check the wellhead top connection to be sure the proper matching connection is on location. If rigging up on internal tree thread connections, be sure to inspect their condition.
4. Consult with the company representative about the work to be performed.
5. Back the truck or trailer into a convenient location and unload the heavy equipment needed for rig-up such as gin pole, lubricator, wireline valve, etc.
6. Move the truck or trailer out a minimum of 50 feet from the wellhead if possible.
7. Before rigging up the surface equipment, the truck should be securely blocked so that it will not roll.

8. Close the uppermost wellhead valve. If it is a gate valve, count the number of rounds the wheel or handle makes to fully close the valve. Always use the uppermost valve as the working valve and save any valve(s) below as a master for emergency use only.

9. Remove the top connection and install the necessary adapter to fit the bottom connection of the wireline valve.

10. If a gin pole is used, it should be raised at this point and secured to the wellhead with a $^5/_{16}$-in. or larger steel chain and tightened with a ratchet type chain binder. (Do not use a breakover type boomer.) It should be as near vertical as possible.

11. Inspect the rope and blocks of the rope falls for breaks or any damage. Install and secure the top block into the top of the gin pole and scope out the pole, inserting pins through the holes provided to support each section. These pins should have a small hole in one end for safety pins.

12. Pick up the wireline valve using the rope falls and install it on the wellhead. Never attempt to manhandle the valve.

13. At this time, inspect the stuffing box and repack it if necessary. Insert the wireline through the stuffing box and through the rope socket. With the wireline disc clamped in the vise, run the wire through the rope socket, around the disc and tie the knot. (See Fig. 2-1)

14. Assemble the lubricator sections and the wireline tool string, which may consist of the proper length of stem, jars and knuckle joints. Insert all but 12 in. of the tool string into the lubricator.

15. Carry the stuffing box with the rope socket and wireline from the unit to the wellhead, using every precaution not to kink the line. Screw the rope socket to the wireline stem and make it up tight with two 24-in. pipe wrenches.

16. Push the wireline tool string into the lubricator and make up the stuffing box union on to the top of the lubricator. Guide the wireline over the stuffing box sheave and pull it to the bottom end of the lubricator and place it in the wireline clamp. This clamp keeps the tools from falling out as the lubricator is raised.

17. Place the lubricator assembly so that the pick-up eye will be as close to the gin pole as possible to minimize any side load on the gin pole.

18. Guide the lubricator during pickup to prevent hitting any wellhead fittings.

19. When the bottom of the lubricator is about even with the union on the top of the wireline valve, tie off the pull rope to the flow line or other piece of heavy equipment on the wellhead.

20. Secure the hay pulley, with weight indicator/converter attached, to the wellhead with a $^1/_4$-in. steel chain or steel cable. Care should be taken to position the assembly such that it will not interfere with operation of the wellhead valves and not cause unwanted sideloading on the lubricator. Place the wireline in the hay pulley and pull up the slack line with the unit. The hay pulley should be mounted with the head of the latch pin on the up side.

21. When all of the slack line has been taken up, the wireline clamp can be released and removed from the lubricator. The wireline should make a 90 degree angle around the hay pulley for proper weight indicator operation.

22. Lower the wireline tool string until the bottom protrudes from the lubricator at a convenient working level. The remainder of the wireline tool string is then made up onto the upper portion.

23. Set the odometer of the counter assembly to zero, with the bottom of the tool string as near the tubing hanger as possible. This point should be used as zero point for all subsequent trips of the wireline tool string. Note that in many cases the well's downhole equipment will be encountered shallower than is specified on mechanical sketches. This is because many operators base all well measurements on the original drilling rig's kelly bushing height, which is usually many feet above the tubing hanger. Therefore, before tools go downhole, the calculated adjustment from TH to RKB should be made.

24. Pull the tool string back up into the lubricator, and set the lubricator on the wireline valve. Make up the lubricator onto the wireline valve and close the bleeder valve. Pressure testing lubricator assembly to twice the anticipated surface pressure should be to the operator's discretion, since high pressure equipment is only tested to 1.5 times the WP, but in any event should comply with 30 CFR 250 or API 14B. Bleed the pressure off through the bleeder valve.

25. Open the closed valve on the wellhead very slowly until the pressure has equalized into the lubricator. Check carefully for any leaks then open the valve fully.

26. At this point, the wireline valve should be tested. Close the rams of the valve and release the pressure from the lubricator through the bleed-off valve. There should be no leaks through the valve rams or the equalizing valve.

27. Close the bleeder valve and open the equalizing valve. When the pressure has been equalized in the lubricator, close the equalizing valve, open the wireline valve rams and lower the wireline tool string into the tubing.

28. When the trip with the tools has been completed and the bottom of the wireline tools are above the top valve

on the wellhead, close the upper wellhead valve, then release the pressure from the lubricator through the bleeder valve.

29. On all locations, ensure that all well fluids bled from the lubricator are contained and not allowed to contaminate the area.

30. Unscrew the lubricator union and pick up the lubricator with the rope falls. The helper will swing the lubricator to one side and the wireline operator will slack off on the tool string to a convenient working level to change tools.

31. When wireline operations have been completed, lower the tool string out of the lubricator. Have the helper close the jars and walk out with them. He will cut the line approximately 6 in. from the rope socket, holding onto the cut end of the line until the wireline operator has pulled it up into the lubricator, then step back in the clear until the end has been pulled clear of the hay pulley. The six inches of line left on the rope socket must be bent 180°, with the end resting as close to the remaining line as possible.

    The rigging-up procedure is reversed for rigging-down.

32. Replace the wellhead connection and pressure gage. The wellhead valve should be opened to check for any leaks in the connections. When all tools have been reloaded on the wireline unit, the wellhead must be wiped clean and the surrounding area cleaned of any trash or debris that might have accumulated during wireline operations.

33. Replace any objects which were moved in Step 1.

Marine Locations, Inland Waters

1. Follow Steps 1 through 4 of Land Locations.
2. Make sure the boat is anchored securely and as convenient to the wellhead as possible.
3. If a ramp or gangplank is needed, it must be firmly secured and the top surface prepared to provide good footing.
4. Follow Steps 8 and 9 of Land Locations.
5. Remove the top connection and adapter with connection to fit the drain sub. This drain sub must be equipped with a bleeder valve to drain any oil trapped below the bleeder valve on the lubricator. It will be equipped with a union on top to fit the union on the wireline valve.
6. The hoist on the boat needed for rig up should be equipped with a steel cable having a minimum O.D. of $^{5}/_{16}$-in.
7. Pick up and install the wireline valve with the hoist. Do not attempt to manhandle the valve.
8. Follow Steps 13 through 18 of Land Locations.
9. The lubricator assembly will be raised with the hoist to a point just above the wireline valve.
10. Secure the hay pulley to the wellhead with a $^{1}/_{4}$-in. steel chain or cable with the latch pin on the up side, and the converter for the weight indicator attached.
11. Place the wireline in the hay pulley and close the latch. Pull all of the slack line onto the drum of the unit. The wireline clamp can now be removed and the tools lowered to a convenient working level.
12. Follow Steps 23 through 28 of Land Locations. Attempt to monitor SCSSV pressure downstream of the isolation valve with a guage.
13. If the well being serviced is an oil well, the valve on the drain sub must be opened to drain any oil trapped below the bleeder valve on the lubricator.
14. Follow instructions in Steps 30 through 33 of Land Locations.
15. Secure all valves and cap the well when shutting down operations for the night.
16. When working on wells with surface pressures of 2000 psi or more, precautions should be taken to purge the air or oxygen from the lubricator. This can be done by displacing air in the lubricator with oil or purging the air from the stuffing box with gas from the well. Elimination of the oxygen inside the lubricator will prevent the possibility of an explosion in the lubricator.
17. Do not pour or pump any combustible liquid into a high pressure well. This is especially true for diesel and paraffin solvent.

Offshore Locations, Platforms and Well Jackets

1. Follow steps 1 through 3 of Land Locations.
2. Consult with the company representative about applicable safety procedures and the work to be performed.
3. Insure that the crane or A-frame is adequate and secure to handle anticipated lifting needs. If using the crane to support the lubricator, use a sling of sufficient length to allow for temporary disconnecting without having to climb the lubricator.
4. Secure and ground the wireline unit to the structure members using $^{5}/_{16}$-in. or larger chain or cable.
5. Follow steps 8 and 9 of Land Locations.
6. Pick up the wireline valve using the crane or rope falls and install it on the wellhead. Never attempt to manhandle the valve.
7. Follow steps 13 through 16 of Land Locations.
8. Guide the lubricator during pickup to prevent hitting any wellhead fittings.

9. When the bottom of the lubricator is about even with the union on the top of the wireline valve, tie off the pull rope to the flow line or other piece of heavy equipment on the wellhead.
10. Secure the hay pulley, with weight indicator/converter attached, to the wellhead with a 1/4-in. steel chain or steel cable. Care should be taken to position the assembly such that it will not interfere with operation of the wellhead valves or cause unwanted sideloading on the lubricator. Place the wireline in the hay pulley and pull up slack line with the unit. The hay pulley should be mounted with the head of the latch pin on the up side.
11. When all of the slack line has been taken up, the wireline clamp can be released and removed from the lubricator. Now the tools can be lowered from the lubricator to a convenient working level. The remainder of the wireline tool string is then made up onto the upper portion.
12. Be sure to temporarily lock out, tag and monitor any surface safety valve (SSV) in the vertical run of the tree using a fusible cap, and the surface controlled subsurface safety valve (SCSSV).
13. Insure that proper documentation is maintained of any production safety system equipment that is removed or replaced.
14. Follow Steps 23 through 28 of Land Locations.
15. On all offshore locations, ensure that all well fluids bled from the lubricator are contained and not allowed to contaminate the envrionment.
16. If the well being serviced is an oil well, the valve on the drain sub must be opened to drain any oil trapped below the bleeder valve on the lubricator.
17. Unscrew the lubricator union and pick up the lubricator with the crane or rope falls. The helper will swing the lubricator to one side and the wireline operator will slack off on the tool string to a convenient working level to change tools.
18. Follow steps 31 through 33 for Land Locations.
19. Insure that any temporarily locked-out safety devices are placed back into operational service.

GENERAL OPERATIONAL INFORMATION

In order to perform wireline operations on an oil or gas well, certain information is necessary to expedite the service work. The following list should be furnished the service company.

1. Company name and address.
2. Person requesting service.
3. Telephone Number.
4. Type of operation to be performed and possible alternative operations.
5. Name of lease and well number.
6. Field.
7. Surface shut-in tubing pressure (highest expected).
8. Surface shut-in casing pressure, if any.
9. Size, weight, and thread type of tubing.
10. Size and weight of casing.
11. Connection on top of Christmas tree
12. Accurate nomenclature of downhole completion equipment and depths of nipples, packers, etc.
13. Time of arrival requested.
14. Person and place to which unit should report.
15. Directions to location.
16. A copy of the current wellbore sketch showing tubing restrictions, gas lift valves, packer depth and bore, open end tubing, bull plugs, elevation measurement perforations, etc.
17. Any special conditions in the well, e.g., tapered tubing string, paraffin, scale, sand, junk, obstruction, excess deviation, or crooked tubing.

If the foregoing information is furnished, a great deal of time can be saved in performing wireline work. Time means money in the sense of contract services, lost production during well shut-in period and sometimes well damage. Damage is mentioned because incorrect information or lack of information can often result in a decision to work in a different manner than normal. For example: A string of retrievable valve mandrels with dummies is in place in a well being worked on and the wireline operator was not informed of the dummies or where they were located in the string. A tool could be run in the hole that might accidentally latch and pull one of the dummies. This would allow completion fluid from the annulus to enter the tubing and kill the zone. This would be a costly mistake which could have been avoided if the wireline operator had been furnished proper and adequate well information.

Accurate description of the well completion and the wireline work to be performed allows the service unit to be properly prepared to conduct the job without costly shutdowns, hotshots, and delays. A sample job dispatch sheet is shown in this chapter.

SAMPLE JOB DISPATCH SHEET

Job No. ______________

Customer ______________________________ Person Calling ____________________ Ph. No. ______________

Time to be on job ________________________________ Date Job is to be done ____________________________

Lease ________________________________ Well No. ____________ Field ____________________________

Type of Service ____

____

Tubing Size ________	Packer Depth ____________	Approx. B H P __________	Safe Run Depth ________
Tubing End ________	Type of Packer __________	Flowing ________________	Casing Pressure ________
Tubing Pressure _____	Perforations ____________	Pumping _______________	Tubing Open In ________
Total Depth ________	Perforations ____________	Shut In ________________	Elevation __________

Tree Connection ____

Direction to Location ____

____

____

____

Special instructions to operator ____

____

____

____

Employee receiving this job ________________ Current Date ________ Job assigned to Oper. ______________ Helper ____________________

Special Tools and/or Materials assigned to this job:**	Disposition (*Check one*) Charged Customer*	Returned to stock: Good Condition	Returned to stock: Need Repairs	Left to Relief Oper.

**The above tools and materials listed were issued to me and are my responsibility to care for and account for their disposition.

Operator ________________________________
SIGN

*WLWO&OR No. ____________

Operator list additional tools and materials assigned to job as it progresses

MEMO FROM OPERATOR: (Pertaining to out of ordinary circumstances encountered on this job.)

____

____

____

Factors to Consider in a Planned Wireline Operation

The following factors should be taken into consideration before performing any wireline operation:

1. Gage run
   a. A gage run is to be made to a designated proposed operations depth.
   b. In a deviated or crooked hole special precautions should be taken if landing nipples are located above a planned swabbing depth.
2. Paraffin depth
   a. If possible, set flow control equipment below paraffin line.
   b. Paraffin may foul flow control and should be removed before setting or pulling flow control equipment.
3. Running depth of bottom hole pressure instrument
   a. A dummy wireline run should be made before instrument and tool runs.
   b. Operator may not want to pull flow control equipment to run bottom hole pressure.
   c. Control set in landing nipple may prevent instruments or tools from going out into casing if lost in hole.
4. Annular fluid weight
   a. If tubing is plugged and pressure bled to zero, differential may collapse tubing.
   b. Calculations should be made to evaluate changes in pressure conditions.
5. Temperature
   a. Flow control equipment should be set deep enough to prevent freezing due to pressure drop through bottom-hole choke or regulator, etc.
6. Crooked tubing or deviated hole
   a. Wireline service tools are affected by deviated holes or severely crooked tubing strings. If this is anticipated, landing nipples should be placed higher in the tubing string than normal in order to service them properly and safely.
   b. In highly deviated shallow wells or slightly deviated deep wells, substantial friction drag can occur. Special lubricants can solve some friction problems. The overall effect of friction will greatly limit the jarring action of the wireline tools.
   c. In a highly deviated hole, care should be taken when working out the end of the tubing. A limber assembly should be utilized to ensure that the tools will be flexible enough to come off the low side of the casing and go back into the tubing.
7. Restrictions in tubing strings (mechanical)
   a. Nominal internal diameter of tubing.
   b. Christmas tree hangers, swages, packers, packer stringers, equipment, etc., should be checked for full or compatible bores and properly beveled on inside.
   c. Packer and stringer bores.
      (1) Packer bore restrictions may often dictate changing internal diameter of landing nipple and other completion equipment in order to service properly.
      (2) Landing nipple internal diameters should be given proper consideration for equipment sizing.
   d. Blast nipple (joint) bores may be restrictive and should be considered in multiple combination tubing string wells.
8. Sand Production
   a. Sand hinders wireline servicing severely. Placement of control equipment should be considered before beginning any wireline operation.
9. Pressure
   a. All equipment should be rated to handle maximum anticipated pressure.
10. H_2S or CO_2 environment
    a. Refer to Special Problem Section in this chapter.
    b. Refer to Safety Recommendations in this chapter.
11. All surface safety valves (SSV) and surface controlled subsurface safety valves (SCSSV) should be temporarily placed out of service before performing any wireline work.
12. Logistics
    a. In remote locations (i.e. offshore), additional or backup equipment should be considered, as it may be difficult to obtain this equipment on a timely basis.
13. Space limitations
    a. Vertical.
    b. Areal.
14. Support facilities
    a. Cranes or gin poles to aid in setting up the lubricator.
15. Timing of operations
    a. Time wireline operations to leave the well in a secure condition overnight.

TYPICAL OPERATIONS

This section deals with the use of running tools, pulling tools, and various devices used in conjunction with wireline activities. The running and pulling tools were developed to facilitate the handling of mandrels, locking devices, etc.

Wireline service tools were also developed to facilitate testing and remedial well work activity such as bottom hole pressure and temperature determination, tubing and casing caliper surveys, tubing perforation, anchors, etc.

Running Tools

Flow control devices must, of necessity, be designed to be placed in the wellbore by vertical movement of the tool string.

1. The tool shown in Fig. 4-1 is used to run and set a slip type lock mandrel. This tool requires only upward driving action to set the slips securely, expand the sealing element, and release from the mandrel.

2. Fig. 4-2 illustrates a running tool used to place a collar lock mandrel. This tool also requires only upward driving action to lock the mandrel, expand the element, and release.

3. Fig. 4-3 is a running tool used to set a tubing collar stop. The stop is locked into the recess of a tubing collar by an upward pull on the wireline.

4. Fig. 4-4 shows a running tool that is used to run and set slip type locks, some collar stops, and circulating devices. Downward action is required to set and release from the lock, stop, or circulating device.

5. Certain running tools require both downward and upward force to set and release from the lock or mandrel. Fig. 4-5 illustrates a tool that is used to set a selective landing nipple lock. This tool holds the locking keys of the mandrel retracted while running and when the proper landing nipple has been reached, downward driving action with the tool string shears a pin releasing the locking keys, which move into a recess in the landing nipple, retarding any upward movement. Upward driving action then shears tangential pins that are retaining the running tool to the inner segment of the lock mandrel allowing it to release.

6. Fig. 4-6 illustrates a running tool used to select and install a lock mandrel in any one of a series of landing nipples of the same size, having the same internal profile, the selectivity being designed into the running tool. Briefly, the assembly is lowered to just below the landing nipple. It is pulled back up through the nipple which forces the locking keys into the locating position. Downward driving action with the tool string shears a pin in the upper portion of the running tool, allowing that part of the tool to move down to force an inner segment of the lock mandrel down behind the keys, securely locking them in their respective groove in the nipple. Upward driving action then shears a pin in the lower part of the tool, releasing it from the lock mandrel.

Pulling Tools

Tools to pull locks that have outside pulling flanges are illustrated in Fig. 4-7. These tools are more or less universal in design, all having virtually the same principle of operation. The engaging dogs of these tools are designed to latch the pulling flange of the lock mandrel, with matching bevels to insure firm contact. Some locks require that the pulling tool have a longer reach than others, which is supplied by changing the inner core to a shorter one which gives the dogs longer reach. These pulling tools are designed to be released from the pulling flange, should the device be stuck, by shearing a pin in the upper part of the tool. They are available in one type that shears the pin by downward driving action (Fig. 4-7 A and B) and another type by upward driving action (Fig. 4-7 C and D).

Tools to engage internal pulling necks, illustrated in Fig. 4-8 are equipped with a set of spring loaded dogs that retract on a tapered inner mandrel as the tools are set down on a lock mandrel, and are forced downward by the spring and out into a groove at the top of the mandrel. These tools are also equipped with a shear pin that requires downward driving action to shear (Fig. 4-8 A) which allows the dogs to move back up on the inner mandrel and release from the pulling neck of the lock mandrel. This tool is sometimes used as a running tool to install some locks that require downward driving action to set. Fig. 4-8 B illustrates an adaptation of this tool to convert it to a shear up to release type. It is used sometimes when extensive downward driving action is required to release a lock mandrel.

Tubing Conditioning Tools

When installing any subsurface flow control device in the tubing, it is imperative that efforts first be made to determine that the control device will pass unimpeded through the tubing to the desired setting depth.

A tubing gage (Fig. 2-9) is recommended to be run to make this determination. The tubing gage is available for all sizes of tubing, including heavy wall. Should this tool stop in the tubing before reaching the desired depth, an impression block (Fig. 2-14) should be run next to determine whether an object is in the tubing. The impression block should be carefully set down on the obstruction, the jar picked up, and one good downard blow made. The impression block is then pulled out of the hole and examined. Close observation of the imprint made in the lead or babbit face of the block will determine what steps should be taken to remove the object. Should the tubing contain mashed places, a swaging tool (Fig. 2-11) can be jarred down through the tight spot, jarred back up through it repeatedly, until it will fall through freely.

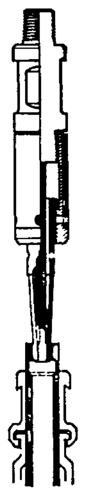

Fig. 4-1 — Slip type

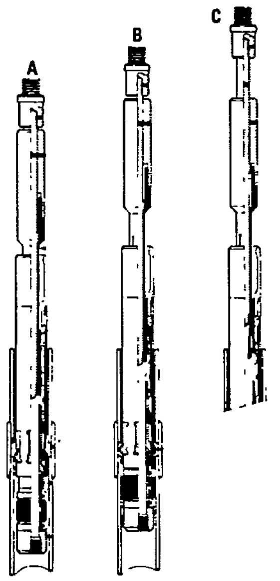

Fig. 4-2 — Collar lock type

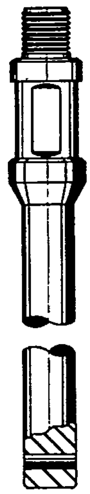

Fig. 4-3 — Collar stop type

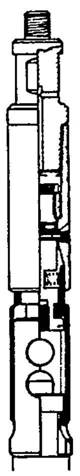

Fig. 4-4 — Slip type

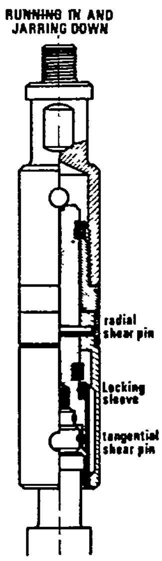

Fig. 4-5 — Nipple type

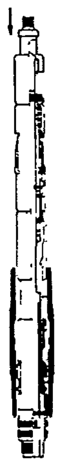

Fig. 4-6 — Nipple type

Fig. 4-1 through 4-6 — Running tools

Burrs or nicks are sometimes encountered in the tubing, most commonly at the joint end, caused by inadvertently striking the pin end of the joint on the coupling when stabbing. These burrs could be injurious to the sealing elements of control devices to be installed and should be removed. A tubing broach is illustrated in Fig. 2-12. A tubing broach is designed to be used in stages: running the smallest size first, then the next larger, until the restriction is completely removed.

Paraffin that has solidified on the internal walls of the tubing from near the top to a depth that varies according to temperature and well conditions can be successfully removed by wireline methods. Numerous tools have been designed through the years to remove these deposits, all of which accomplish the same results. Each type has advantages over the other: the gage-cutter type (Fig. 2-9) performs best when the paraffin is caked hard on the walls. The scratcher (Fig. 2-10) performs best when restrictions, such as landing nipples, are in the portion of the tubing to be cleaned of paraffin.

Oil and gas production may be interrupted by accumulation of sand in the wellbore, which forms bridges that completely plug off any flow. The sand may have entered the wellbore along with the oil or gas being produced from unconsolidated sand formations. Experience has proven that the sand plugs can be successfully removed both safely and economically with sand bailers that are designed to be operated by wireline methods. All pump-type bailers (See Fig. 2-17) operate on the same principle, i.e., a pumping action which pulls the sand up into the housing of the bailer where it is trapped by a ball or flapper type check valve. They are available in sizes that can be used in any size tubing.

Precautions must be taken when performing bailing operations. Some of these include keeping the tubing full to the surface with oil or some other fluid when bailing in an oil well and applying gas or air pressure when bailing in a gas well. This will eliminate the possibility of the tools being suddenly blown up the tubing, if the bailer suddenly breaks through the sand bridge into pressure that may be trapped below the bridge. The operator should also move the entire tool string up the tubing slightly after each stroke to avoid the possibility of the bailer sticking in the sand.

If the bailer fails to pick up any sand when bailing from the top of a subsurface control tool, a lead impression block should be run to determine if the top of the control is clear. If the top of the subsurface control is not clear, and sand remains around the pulling neck, a hydrostatic bailer can be used to remove the sand. This bailer (See Fig. 2-18) consists of a barrel some four to six feet long, having a shear disc at the bottom, with the barrel sealed off from well pressure. When the tool string stops on the subsurface control, a few downward strokes with jars pierces the shear disc, causing the barrel to be exposed to well pressure and a sudden influx of fluid. This picks up any remaining sand from around the top and alongside the pulling neck of the subsurface control. Like the sand pump, a ball check closes and holds the sand in the barrel. *Caution must be taken when this type bailer is opened at the surface after a trip has been made, due to pressure that may be trapped inside the barrel.* The safety screw assembly is designed to automatically release any internal pressure; however, this exit port could be plugged and not allow the trapped pressure to release. To be sure no pressure is trapped inside, the set screw holding the stainless steel ball on seat should be unscrewed allowing the ball to move off the seat. This should release any trapped pressure. (See Chapter 2, page 16 for more information on sand bailing)

Positioning Tools

Sliding sleeves described in Chapter 3 are designed to be shifted from the closed position to the open position or vice versa using wireline methods. The tools used to perform these operations are referred to as positioning or shifting tools. Fig. 4-9 illustrates a type tool that is used to shift the sleeve in either direction. The spring loaded keys locate in the matching profile of the inner sleeve. Jar action with the tool string moves the inner sleeve to the open or closed position. When this inner sleeve has been moved to the fully opened or closed position its travel is arrested by an internal shoulder. This shoulder also acts to release the shifting tool by forcing the keys inward and off the shoulder of the inner sleeve. If the sleeve is impeded for some reason and cannot be moved to the maximum closed or open position, a shear pin in the positioning tool will shear, allowing the keys to be released.

Bottom Hole Pressure (BHP) Surveys

Instruments run on wireline to record the bottom hole pressure and temperature of shut-in and flowing oil and gas wells have been used many years. Periodic surveys are made with these instruments to measure static bottom hole pressure as required by certain State and Federal laws and the lease operator. The information obtained is used to determine reserves, future life, completion efficiency, need for well stimulation and other producing or injection well parameters.

A suggested procedure for running a BHP survey follows:

1. A complete inspection of the gage, clocks and accessories must be made before going to the well location.
2. Upon arriving at the location, discuss the job with the company representative in relation to:
   a. Well pressure.
   b. Depth to be surveyed.
   c. Stops to be made.
   d. Previous surveys, if any.
   e. Subsurface controls in well, if any.
   f. Well conditions:
      (1) sand
      (2) salt water production

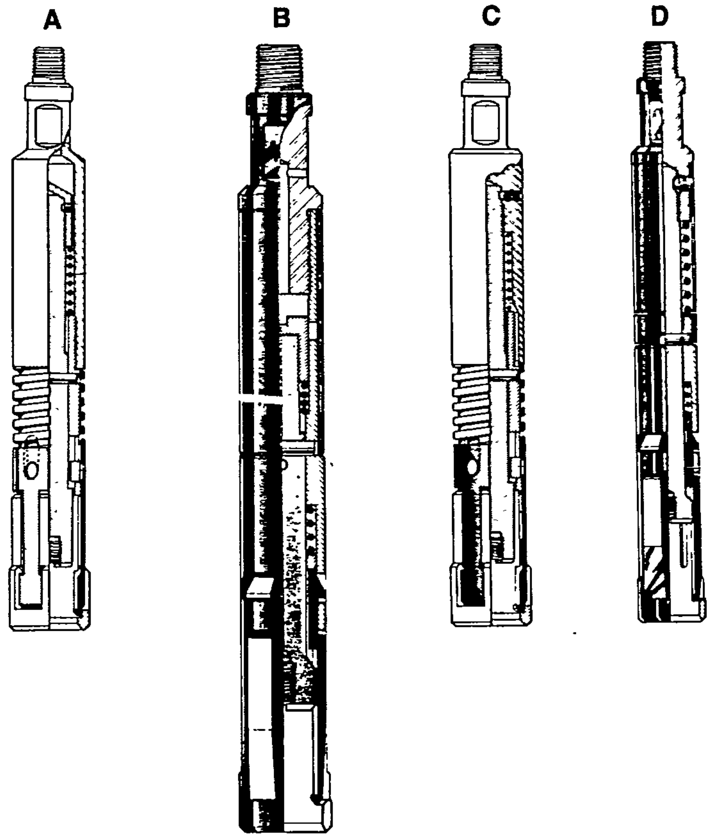

Fig. 4-7 — Pulling tools

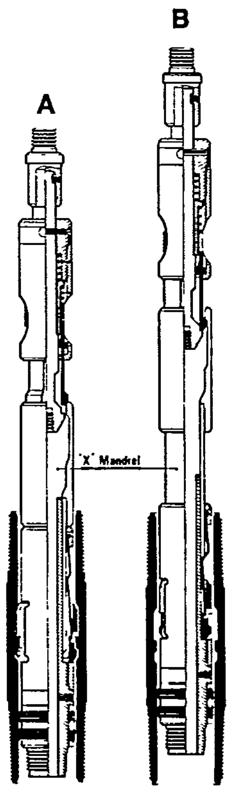

Fig. 4-8 — Pulling tools

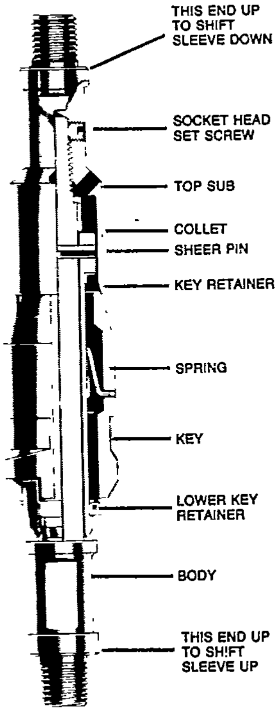

Fig. 4-9 — Sliding sleeve shifting tool

(3) crooked tubing

(4) how long the well has been shut in

3. Prepare the well for the bottom hole pressure survey. Pull any subsurface controls. Make a dummy run to the depth of the survey.

   If crooked tubing is suspected, five feet of stem should be run below the jars, picking up at least once every 500 feet below 3000-5000 feet. Pick up far enough to be certain that the tools are moving up the hole rather than stretching the line.

4. Prepare the pressure gage for the survey.

5. Determine the depths or stops at which the pressure will be recorded. The production engineer or company representative may furnish these figures. When not advised by the customer, the following is a good practice:

   Example: The well is 14,742 ft deep. Stops should be made at 2000 ft intervals to a point 1500 ft above the gaged bottom and then at 300 foot intervals to the gaged bottom. (Gaged bottom, in this case, means the point at which the tubing gage was run to ensure that the tubing was free from obstructions.)

   Thus, stops will be made at the following depths in feet: 0, 2000, 4000, 6000, 8000, 10,000, 12,000, 13,242, 13,542, 13,842, 14,142, 14,442, 14,742.

   Frequent stops near bottom should give some indication of the fluid gradients, whether liquid or gas. With this information, the survey can be extrapolated beyond the point to which the gage was actually run.

6. Usually, the survey is made with stem and a knuckle joint. When sand is suspected knuckle jars should be run. The pressure gage should be run at a reasonable and consistent rate of speed. There should be no sudden stops or jarring of the line. Any time the line is stopped, a notation should be made. The length of the stops will be determined by the clock rating. A good rule of thumb is to stop one minute for each one hour rating of the clock. For example: Three one-minute stops for a three-hour clock. When completing the survey report, be sure to note the exact depths of the stops. This is very important, as a few feet will change the gradient. If a dead weight test of well pressure is taken, it should be taken while the pressure gage is in the lubricator with well pressure on it.

7. After removing the gage from the tool string, inspect the chart. Some things to look for are:

   a. A good base line. The base line must be visible and straight. If the base line is absent or wavy, rerun.

   b. The correct number of stops made should be visible on the chart. Count them. If they are not clearly visible, the test must be rerun.

   c. Determine if the chart has recorded the full survey. If the chart is acceptable, the following information should be inscribed on the upper right corner of the chart:

      (1) Well name and location

      (2) Date

      (3) Wireline Report number

      (4) Clock used

      (5) Element number

   d. The chart folder should be filled out completely. The more information about the well, the better the interpretation will be.

8. If the survey is a good one, clean the instrument and prepare it for transportation.

9. To eliminate the necessity of leaving the BHP gage suspended on the wireline while making extended surveys, a hanger tool is available that provides a means of suspending the gage in a tubing coupling recess and removing the wireline and tools. It is commonly referred to as a lug type "bomb" (bottom hole pressure gage) hanger.

Tubing and Casing Caliper Surveys

Deterioration of production pipe strings in oil and gas wells causing leaks and, in some cases, parting of the pipe present expensive problems to the owners and operators. These deteriorating conditions should be detected before they become more expensive problems. Instruments to survey the well tubing for these conditions were developed in the early 1940's and run on electric lines. Inability to pack off the electric line running through the stuffing box caused problems on wells having surface pressure.

To overcome this problem, instruments were developed in the mid-1940's that could be run on solid steel lines in wells under pressure, to detect, measure and record on a metal chart, internal corrosion damage in tubular goods. (Fig. 4-10).

After each survey is made, the caliper chart, bearing the well name and number, and any other pertinent information, is sent to the laboratory where it is enlarged and a comprehensive report written on the survey. This report is available to the well owner and copies are filed by the service company making the survey.

Detailed instructions for making a caliper survey are available in booklet form and can be obtained from service companies upon request.

Fishing Tools and Procedures

Fishing out wireline that has been lost in the tubing while performing a wireline operation requires that the operator follow certain steps to obtain the best results and not cause the condition to become worse. These steps will be discussed in this section along with various fishing tools.

Assume that excessive jarring of the tool string causes the line to part at the surface. Then assume that the line broke at a point which left the end of the line extending through the lubricator. The proper procedure to retrieve the parted line is to close the wireline valve and secure the end of the broken line by splicing onto the line still on the reel, if possible. Release the pressure in the lubricator and install a cutter bar (Fig. 4-11). The blind box of the cutter bar must be large enough to strike the center of the rope socket of the fish (tools and line left in the well). Open the wireline valve and drop the cutter bar. Sufficient time must be allowed for the cutter bar to fall to the stuck tools. When the cutter bar cuts the wireline at the fish, the line can then be spooled onto the drum of the unit. A new line may then be spooled on to the wireline unit and the cutter bar fished out.

Assume the end of the broken wireline falls below the wireline valve. The cutter bar could then be tied onto another tool string by means of a piece of string, lowered to a point calculated to be below the end of the broken line; the tools snapped sharply, breaking the string and letting the bar fall. To calculate the approximate depth of the top end of the line,

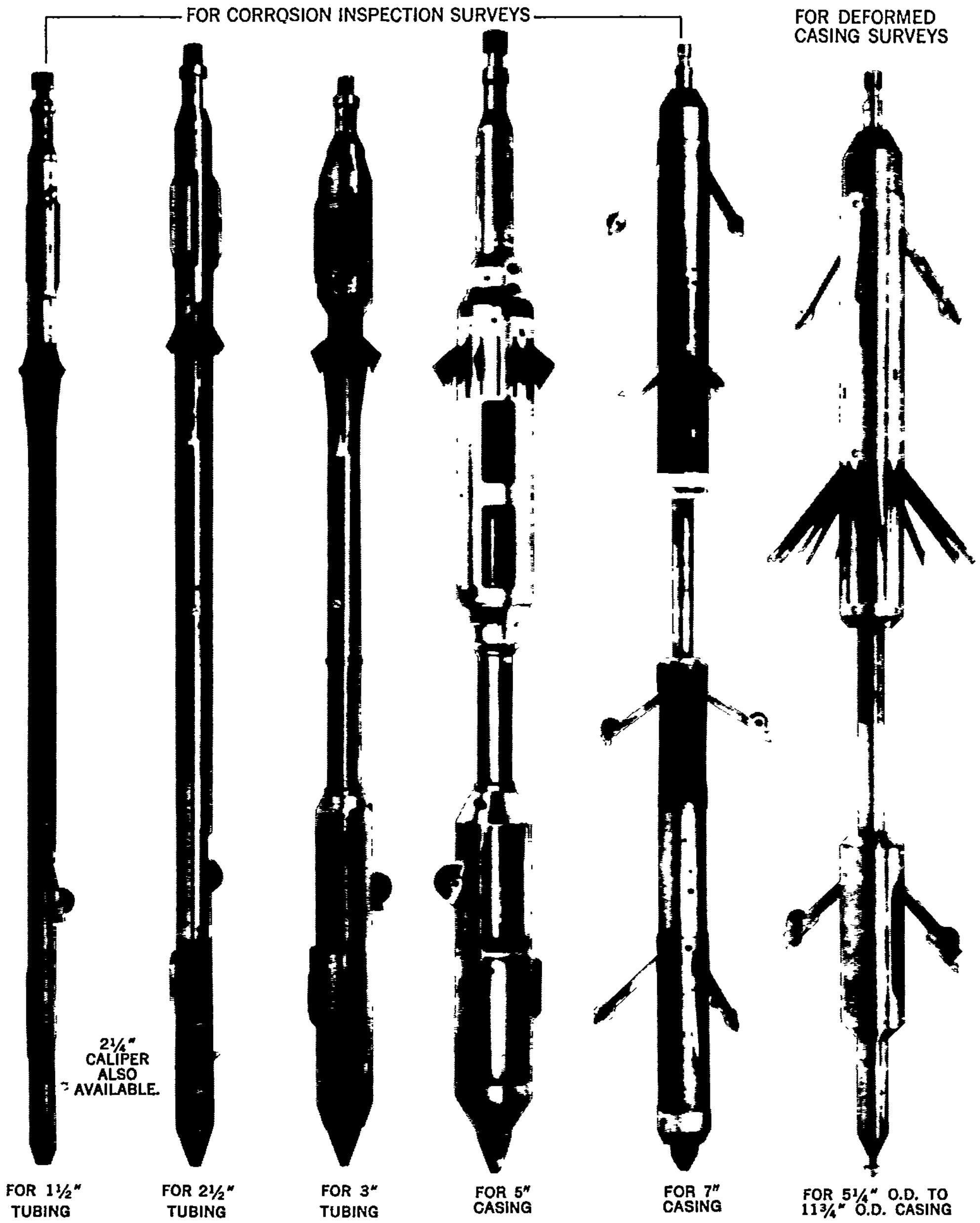

Fig. 4-10 — Caliper instruments

a good rule of thumb states that the line will fall about 3 to 5 feet per 1000 feet of line in 2 in. tubing, due to friction of the line on the wall of the tubing. For example, with tool string at 10,000 feet, the end of the line would be somewhere between 30 to 50 feet and the surface.

Another type of line cutter that could normally be run with the tool string is the sidewall cutter (See Fig. 2-24). It can be set at any point in the tubing, and the line cut and fished out in segments. This reduces the possibility of the two lines becoming entangled. Provision is also made for pinning the cutter knives in the retracted position and dropping it as a cutter bar. After the sidewall cutter has had sufficient time to fall to the stuck tools, a weight bar must then be dropped to shear the pin holding the knives, causing them to ride up on the taper and cut the line.

A wireline cutter, marketed under the name Kinley Snepper (Fig. 2-23), must be assembled on to the line. It employs a cutter knife that is actuated upon contact with the rope socket of the stuck tool string. When the line is cut, a crimper, designed into the tool is also activated and crimps the cut-off line to the snepper which is retrieved as the line fish is pulled out.

Proper steps must be taken to locate the top of the broken wireline when fishing operations begin, to avoid the possibility of jamming too much of the line around the wire grab. Fig. 4-12 is a diagram of a wire finder used successfully to locate and coil the top of the wireline to allow the wireline grab, or spear, (Fig. 2-19) to engage it. The wireline finder is a cylindrical shaped tool made of fairly soft steel and designed so the bottom portion can be swaged out to scrape the tubing walls. The drift diameter of the tubing must be taken into consideration when attempting to locate and coil the top end of the line.

When the end of the line has been located, picking up the locator and setting it back down several times will coil the end of the wireline enough that the wireline grab will engage it.

A scratcher type wire finder, Fig. 4-13, can also be used and has some advantage over the coneshaped tool. The wires on the scratcher are flexible, allowing the tool to pass through restrictions and spring back out to scrape the walls of the tubing.

To engage wireline in the hole and pull it to the surface, a wireline grab (spear) is used, (See Fig. 2-19). The prongs are made of fairly soft steel, slightly concaved internally where the barbs are located. Setting the grab down into the coiled line should be sufficient to grab the line and pull it to the surface. Assuming that the line has been cut at the stuck tool string, the line is pulled above the wireline valve, the rams closed and pressure released from the lubricator. A new line may then be spooled on the drum of the unit, the cutter fished out, and operations begun to remove the stuck tool string. The wireline retriever, described in Chapter 2 and illustrated in Fig. 2-20, is another fishing tool. The skirt of the tool is a floating member that locates the end of the line and stops when the line is threaded up through the bore, alongside the tapered inner mandrel, where it is trapped and held when the tools are pulled up again.

When the ball of wire is compacted to the point where the two-prong grab will not engage it, a center spear type tool, Fig. 4-14, is sometimes used to drive into the ball to loosen it and pull out some of the line.

When the tool string is in or below entangled wireline, the rope socket is no longer in the clear, making it impossible to cut the line by dropping a cutter bar. When this happens it is necessary to provide a place for the cutter bar to cut. This can be accomplished by installing a go-devil (Fig. 2-22) onto the line and dropping it. Once the go-devil is in place, a wireline cutter is then used to cut the wireline which is above the go-devil. After the line has been pulled out, another string of tools is rigged up and the cutter bar and go-devil are retrieved. (See Chapter 2, page 16 for more information regarding Wireline Fishing)

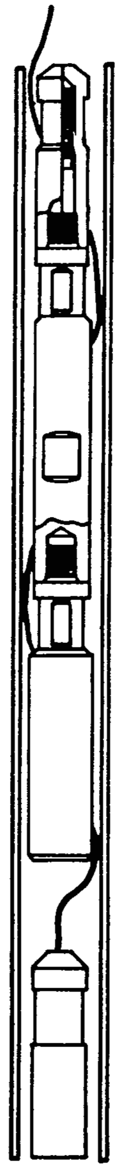

Fig. 4-11 — Cutter bar

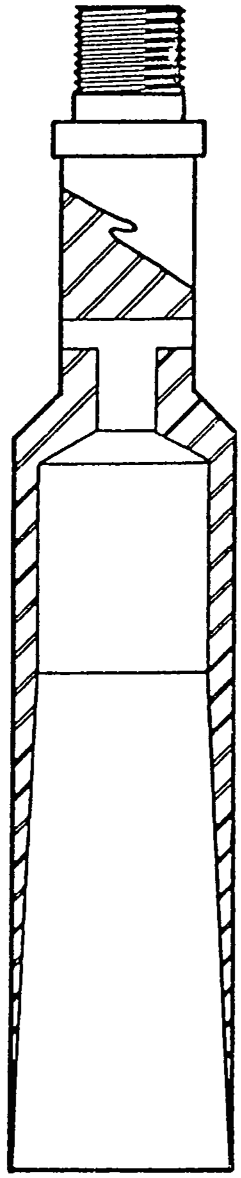

Fig. 4-12 — Cone shaped wire finder

General Fishing Guidelines

1. Accurate record keeping is critical. Measure lengths and diameters of all tools to be run. Save all wire lengths as they are recovered, measuring each length will indicate the remaining wire length in the well. Test check proposed tools at the surface to insure they will latch desired downhole tools.

2. Use adequate lubricator length to cover work string and the maximum length of any tools that could be recovered. Make sure to use the wireline valve to contain the well pressure when removing the lubricator. When fishing wire, do not use the well's gate valve as closing it could cut any wire brought up the well by the fishing tool string.

3. Prior to running a fishing tool, discuss any possible options/consequences with other operators. Try to think of two other tools that could be run if the first is unsuccessful.

4. Remove any broken wire first before attempting fishing for tools.

5. Use an impression block when necessary to check downhole conditions.

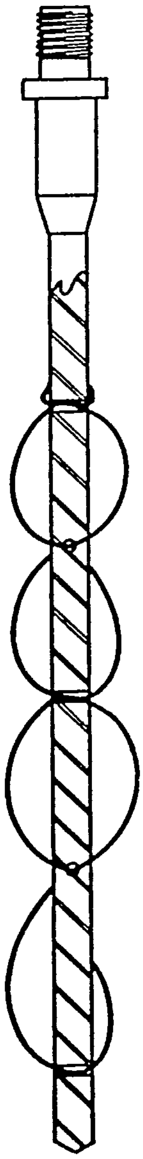

Fig. 4-13 — Wireline finder (scratcher type)

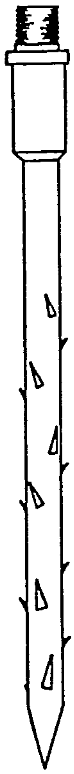

Fig. 4-14 — Center spear

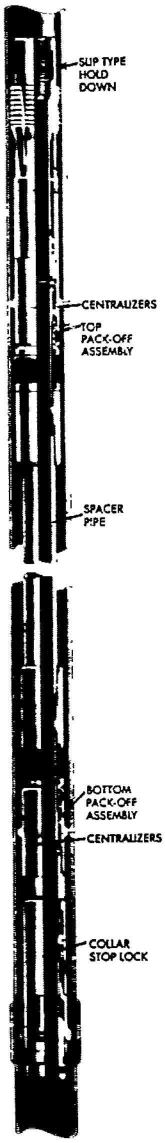

Fig. 4-15 — Pack-off anchor

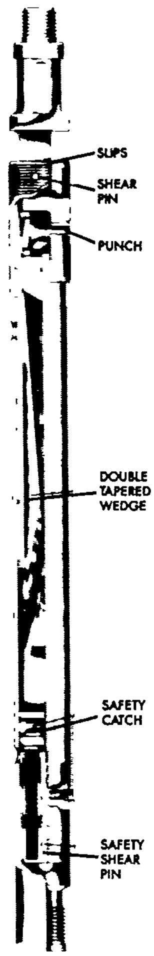

Fig. 4-16 — Mechanical tubing perforator

Fig. 4-17 — Vertical section 2 in. HP perforator

Pack-Off Anchors

Pack-off anchors are designed to straddle and pack off holes in the tubing string so that production of the well can be continued without pulling the tubing. Holes may occur opposite the top perforations in a dual completion or anywhere else in the tubing string. If the tubing that is to be packed off is under pressure, the length of the pack-off tool is controlled by the length of the lubricator. If the well can be killed so that the tubing can be opened to atmosphere, the length of the pack-off is determined only by the tensile strength of the wireline handling the assembly. The assembly illustrated in Fig. 4-15 employs an internal diameter through the anchor. This pack-off is particularly suited for installations where high production volumes are desired. The pack-off anchor may be installed in only two trips with the wireline. The unit may be run and retrieved by regular wireline methods, under pressure. The large internal diameter of the pack-off equipment permits properly sized bottom hole pressure instruments to pass through.

This installation in collared tubing utilizes a collar stop as a bottom stop. For streamline tubing without collar recess, a slip-type lower stop is available. The upper pack-off section is usually anchored with a slip-type hold down. Under certain conditions, the pack-off may be run without the upper hold down. The sealing elements are set by downward jarring with the wireline tools and are designed to seal against the tubing wall and be held in the set position by a mechanical lock incorporated into the pack-off section. (To set these elements, a minimum of eight feet of stem is recommended.) The pack-off is a pressure-balanced unit designed to carry a pressure differential from above or below. Pressure rating for all pack-off anchors is dependent upon packing elements and the condition of the tubing string.

Tubing Perforators

When no other commingling devices are located in the tubing string, or commingling is needed at a level where no device is located, a perforator may be run on wireline tools to perforate the tubing to circulate fluids, install gas lift valves, or perform other operations requiring passage between the tubing and tubing-casing annulus.

Two types are available. One is activated mechanically by manipulating the wireline tools (Fig. 4-16). The other employs a powder charge to drive a tapered wedge behind a punch to force it outward and cause it to penetrate the tubing wall (Fig. 4-17). The mechanical type perforator uses a round flat end punch to penetrate the wall. The punch is retracted by a shear pin while running. The tool is set down on a tubing stop that is run ahead of the perforator or attached to the bottom of the perforator and set during the same trip. After the perforator is set on the stop, a few light downward stokes with the jars shears the pin retracting the punch. Upward jarring then pulls the tapered wedge behind the punch, forcing it outward. The housing is held stationary by serrations on the opposite side from the punch. When the punch has completely penetrated the tubing wall, the taper of the wedge is reversed, retracting the punch and freeing the assembly for its return to the surface. The tool may be used in both standard weight and heavy wall pipe.

SPECIAL PROBLEMS

The purpose of this section is to point out some of the special problems associated with producing oil and gas wells, and to suggest some wireline procedures which may be used to eliminate, minimize, or control them. Among these problems are corrosion, sand, paraffin, hydrates, and crooked tubing. Some of them are common to all geographic locations, and others are troublesome in only a few areas. The information contained herein is general and no attempt has been made to cover specific instances.

Corrosion

One of the major problems encountered in wireline operations and associated equipment is corrosion. All engineering metals and alloys are subject to chemical processes that cause them to lose their identity as metals and return to the natural state in which they were first discovered. This return to the natural state — whether spontaneous or induced — slow or fast — is corrosion.

The most common form of corrosion is called "weight-loss corrosion". As the name implies, it is characterized by loss of weight, pitting, and general roughening of the surface.

A second form of corrosion is commonly known as "stress corrosion cracking". Often this form is of more concern than weight-loss corrosion, since stress corrosion can cause metal failure within a very short time. Ordinary plow-steel wireline has been known to fail overnight when exposed to this form of attack.

Stress corrosion cracking results from a combination of corrosion and stress and generally occurs at points of stress arising from mechanical loading or residual internal stresses resulting from heat treatment or cold work. Stress corrosion failure generally occurs along crystal boundaries and has the appearance of a brittle fracture. Hydrogen sulfide gas is a common cause of stress corrosion cracking.

All of the aforementioned factors are encountered to some degree in wireline tools and equipment. In the case of such equipment, it is important that appearance, strength, and proper operation be maintained for reasons of safety and economy. Since corrosion adversely affects all of these properties, it is necessary to reduce its effects whenever and wherever possible.

Corrosion of Wireline Equipment

When weight-loss corrosion is the major type of corrosion encountered, all of the previously mentioned methods may be used to protect wireline tools and equipment. Painting, plating, galvanizing, anodizing, material selection, all may be used, singly or in combination, to reduce the effects of corrosion. For example, wireline tools may be painted, nickel plated, or anodized. Wireline trucks are often galvanized as well as painted. Many tools are made from stainless steels, Monels, low-carbon steels, cast iron, etc., depending upon the conditions to be met. The wireline itself is generally kept well oiled to retard rusting (corrosion).

In an effort to standardize on suitable materials for hydrogen sulfide service, the National Association of Corrosion Engineers (NACE) has issued materials requirement MR-01-75: Sulfide Stress Cracking Resistant Materials for Oilfield Equipment. NACE MR-01-75, which is periodically updated, lists materials suitable for use to minimize failures due to sulfide stress cracking (SSC). The latest edition of this document should be consulted for information on SSC resistant metals and their limitations.

For use under the conditions outlined, wireline tools and equipment are manufactured from the approved materials whenever possible. One notable exception is the wireline. Wirelines fabricated from materials recommended for sulfide service lack the required strength for heavy duty wireline operations. For light duty service, such as running bottom hole pressure and temperature surveys, Type 316 stainless steel has been found suitable. For general operations, however, this does not have sufficient strength.

NACE MR-01-75 lists a number of high-alloy materials, having relatively high yield strengths, which are resistant to SSC. Many of these materials are available in wire forms. Good results thus far have been obtained with a standard plow steel measuring line in conjunction with a suitable corrosion inhibitor. The use of a standard improved plow steel line that is completely immersed in a good corrosion inhibitor when not in the well, and treated with inhibitor while running in or out of the well, has worked exceptionally well. The improved plow steel line is placed in a 55 gallon drum and completely covered with an inhibitor. It is spooled onto the reel just before the job and is unspooled and returned to the inhibitor drum after the job. A wiper-oiler is used at the hay pulley which is also full of inhibitor. This wiper pulley consists of an oiler with a hole drilled through the bottom and a sleeve welded on each side through the holes.

Stuffing box rubbers are placed in the sleeves and an adjusting screw placed in the ends to tighten or loosen the packing. The gland is tightened on the tree side coming out of the well to clean the line, and loosened on the truck side to oil the line. This procedure is reversed when going in the well.

The heart of the method consists of a special adapter reservoir attached to the lubricator between the stuffing box and the top section of lubricator. A bushing is screwed in the bottom of this adapter with a hole just large enough for the line to run through it smoothly. This forms a small reservoir to treat the line. Outside the reservoir there is a check valve with a needle valve and threaded end. A high pressure hose is connected to this needle valve and a small pump capable of overcoming well pressure pumps inhibitor into the reservoir as the line is raised or lowered in the well.

One other procedure is necessary with this type of operation. The rope socket and all of the boxes on the tool string are filled with inhibitor before they are made up. This will treat the threads and prevent corrosion and stress cracking of the wireline tool joints.

All wireline tools used in the operation such as broaches, gages, pulling and running tools should be immersed in inhibitor prior to running in the well.

Internally Coated Tubing

Well tubing may be internally coated with plastic materials to provide control of corrosion on the inside wall of the tubing. Special precautions should be taken when doing wireline work in wells equipped with such tubing. Wireline tools may be run in coated tubing without severely damaging the coating by close control of wireline speed and careful selection of tools.

Wireline speed should be controlled when going in and coming out of the hole. By controlling the speed, flutter and rattle of the tools and slap and abrasion from the wireline are minimized. Many operators and coating applicators recommend that wireline speeds be kept below 100 feet per minute in coated tubing. Damage to the coating may be further reduced by tool design. Sharp edges on the tools should be rounded or covered with thick non-metallic coatings.

Sand

A second major problem encountered in wireline operations occurs in wells where the producing formation is loose and unconsolidated. In such wells, sand is produced along with the well fluids. This can cause a reduction in or cessation of well production due to formation of sand bridges in the production string or plugging of the perforations. In addition, the abrasive nature of sand erodes or "cuts out" surface and subsurface chokes, choke beans, valves, and sometimes nipples and tubing.

Sand bridges vary in length and may cause pressure to be trapped below the bridge. If a sand bridge forms just above a subsurface control, it will be impossible to pull the control until the sand has been removed by bailing or washing.

In a sand bailing operation, the operator should be aware of existing well conditions. Often the well will bridge over with sand, causing the well to go dead. When this occurs a pressure loss is noted on the tubing. Pressure should be restored either by filling the tubing with fluid or by pressuring up from another well or another source before any excessive bailing is done. This will keep the sand from rising and possibly covering the bailer and tools.

Many procedures for preventing sand from entering the wellbore have been developed, such as plastic-bonded sand screens, formation consolidation with plastic, gravel pack screens, walnut-hull screens, etc. These procedures are often successful in eliminating the sand problem, but are beyond the scope of wireline methods and are mentioned for informational purposes only.

Paraffin

In some areas the produced crude oil and condensate contain quantities of heavy waxes, resins, and asphaltic compounds which remain fluid until temperature and pressure reduction cause them to solidify. If these conditions occur within the tubing, a paraffin deposit begins to build up on the tubing wall. Continued buildup, if undisturbed, may eventually plug the tubing completely.

Several wireline tools are available for removing paraffin, the most common being the paraffin cutter (See Fig. 2-9). In wells where the deposit is slight or soft, the weight of the wireline tools may be sufficient to drive the paraffin cutter down the tubing. If the deposit is heavy or hard, downward jarring may be required to cut through the paraffin. The paraffin thus loosened is removed from the tubing by allowing the well to flow.

A second device for paraffin removal is the wire scraper or scratcher, consisting of numerous segments of stiff wire attached to a small diameter rod (Fig. 2-10). The wires scrape the tubing wall as the scraper is lowered into the well, loosening and breaking up the paraffin so it may be flowed out. Because it has a much smaller diameter than the gage, the wire scraper can be used even when the wellbore is almost completely plugged. Since paraffin removal with either tool does nothing to prevent future deposits, this procedure must be repeated at regular intervals in order to keep the well paraffin-free.

A third device available is one which provides continuous removal of paraffin deposits automatically. This device — called variously a rabbit, automatic scraper, or free piston — is initially installed using wireline methods, but thereafter operates automatically. Further use of the wireline is not required.

Hydrates

Under certain conditions of pressure, temperature, and moisture content, hydrates may form. They are ice-like crystals that are often mistaken for ice because of their similarity in appearance and behavior. Formation of hydrates in or below the Christmas tree can plug the well, freeze valves, and prevent entry of wireline tools. Hydrate formation in wireline lubricators can cause the tools to become stuck and immovable. Leaking stuffing boxes can trigger or aggravate hydrate formation, as can any sudden pressure expansion such as that which occurs when opening needle valves on lubricators. When this happens, a hydrate in the needle valve can plug it, preventing the pressure in the lubricator from being completely bled off.

Once hydrates form, they must be melted like ice. Since considerable time would be consumed waiting for the ambient temperature to melt them, hydrates are melted rapidly by other means. If a source of steam or hot water is available, melting can be accomplished in a relatively short time. In most cases, injection of methanol or ethylene glycol can be used.

Crooked Tubing

Wireline operations may be difficult when the tubing string has sharp bends or extreme vertical deviation such as in crooked or deviated wells. The amount of flexibility needed in the string of wireline tools will vary with the degree of deviation. Lack of sufficient flexibility can result in complete inability of the tools to pass through a section of crooked tubing. Occasionally the tool string may be flexible enough to pass through a crooked section while going down the tubing, but the added length when removing a long choke, safety valve, or other control may prevent the tools from passing up through the same section. For these reasons, it may be necessary to include more than one knuckle joint (See Figure 2-4).

In some instances, the tools may pass in and out of the tubing without difficulty but jar action may be so impaired that the work cannot be completed. In such situations, the use of the knuckle jar (Figure 2-8) may permit the work to be done. On some jobs, it has been necessary to use a tool string consisting only of knuckle joints and knuckle jars. Special lubricants may also be pumped down the tubing string to reduce friction in the tubing string to aid tool passage.

Surface Controlled Subsurface Safety Valves (SCSSV)

Special precautions should be taken when doing wireline work in wells equipped with surface controlled subsurface safety valves (See Fig. 3-14) run on the tubing string. These valves are full opening and will not restrict any wireline tools run in the tubing when in proper order. However, the SCSSV depends on hydraulic pressure generated by a pump on the surface to keep it open. Should pressure be lost on the control line while wireline is in the hole, either by the pump failing or accidental breaking of the control line, the valve will close on the wireline and break the line. This could result in a major fishing job for the wireline and tools lost in the hole. Damage to the SCSSV could also require pulling the tubing string.

In order to prevent accidental closing of the SCSSV during wireline operations, the SCSSV should be put into a temporary inoperative position so that it will not close. Upon completion of the wireline operations, the SCSSV can be placed back in operation and function tested to ensure that it is operating properly.

RECORD KEEPING

It is imperative that accurate records of all wireline operations be provided to the well operator. Current records of flow controls in the hole and where they are located are of paramount importance. Also, the condition of the tubing string (tight spots, sections of high drag, etc.) should be noted. Government agencies require that the well owner have records showing when flow control devices and plugs are pulled, as well as a record of their condition. In some cases the well operator will have wireline record forms available and they should be properly completed before leaving the job or completed and returned to the well owner. REMEMBER: THESE RECORDS ARE THE ONLY DOCUMENTATION OF PREVIOUS WIRELINE OPERATIONS AND THEIR RESULTS. THE MORE YOU KNOW ABOUT A WELL'S CONDITION, THE BETTER YOUR CHANCES OF HAVING A SUCCESSFUL OPERATION.

GOVERNMENT REGULATIONS

Many various government agencies have regulations concerning wireline operations. Requirements may vary depending upon the state or area in which operations take place. Many times written records must be maintained by the well operator. Required information may include: dates that valves were tested, the condition of pulled valves, name of manufacturer, model and serial number. It is therefore imperative that an operator be familiar with the regulations applicable to his area of operation.

GLOSSARY

—A—

Absolute Pressure — Pressure measured from absolute zero pressure. It is ordinarily expressed as gage pressure (the pressure reading on a pressure gage) plus atmospheric pressure, and denoted in pounds per square inch absolute (psia).

Adjustable Choke — A choke in which the position of a conical needle in a seat can be used to vary the rate of flow through the choke.

Alloy — A metal composed of two or more elements, combined to produce certain metallic properties.

Annulus (Annular Space) — The space surrounding pipe suspended in the well bore. The outer wall of the annulus may be the wall of the bore hole or it may be larger pipe.

API — American Petroleum Institute. Founded in 1920, this national oil industry trade association maintains a headquarters office in Washington, D.C. and a Production Department office in Dallas, Texas. It is also used as a slang expression for a job well done (that work is strictly API), or for utter confusion (it's API today, two engines are down). Standards for many items of drilling and producing equipment are produced by industry committees of the Production Department, including specifications for wire rope and solid wire line.

API Gravity — An arbitrary scale to conveniently express the gravity or density of liquid petroleum products. The scale is derived from "specific gravity" according to the following equation:

$$\text{API gravity} = \frac{141.5}{\text{Specific Gravity}} - 131.5$$

API gravity is expressed in degrees, a specific gravity of 1.0 being equivalent to 10° API.

Artificial Lift — Any method used to raise oil and gas to the surface after reservoir energy has declined to the point at which the well no longer produces by natural flow. The most common methods of artificial lift are sucker-rod pumps, hydraulic pumps, submersible pumps, and gas lift.

Atmospheric Pressure — The pressure exerted over the surface of the earth by the weight of the atmosphere. At sea level, this pressure is approximately 14.7 pounds per square inch (psi).

—B—

Babbitt — Metal from which engine bearings are made. Usually consists of tin, copper, and antimony.

Back Off — To unscrew one threaded piece from another.

Bail — To recover bottom-hole fluids, samples, or drill cuttings by lowering a cylindrical vessel, called a "bailer", to the bottom of a well, filling it, and retrieving it. Also, a link of steel attached to pipe elevators for lifting.

Bailer — A long cylindrical container, fitted with a valve at its lower end, used to remove water, sand, mud, or oil from a well.

Barrel — (BBL or bbl) — A common unit of liquid volume measurement in the petroleum industry. One barrel (1 bbl) is equivalent to 42 gallons (158.97 liters).

BBL/D — Barrels per day.

B/D — Barrels per day. (Alternate for BBL/D usually used in drilling reports).

BHP — Bottom hole pressure.

BHT — Bottom hole temperature.

Blank Flange — A solid disk used to dead-end, or close off, a companion flange.

Blind Ram — An integral part of a "blowout preventer", serving as the closing element. The ends of a blind ram are not intended to fit around the drill pipe but to seal against each other and shut off completely the space below. (see "ram").

Blowout — A temporary uncontrolled flow of gas, oil, or other well fluids from a well to the atmosphere. A well blows out when formation pressure exceeds the pressure being applied to it by the column of drilling fluids and measures are unsuccessful in rectifying this situation. Early day gushers were blowouts.

Blowout Preventer and platform (BOP) — Equipment installed at the surface, below the drilling floor on land and platform rigs and on the seafloor of floating offshore rigs to prevent the escape of pressure either in the annular space between the casing and drill pipe or in an open hole during drilling and completion operations. Also used during some workover operations.

Boll Weevil — An inexperienced rig or oil-field employee (slang). Sometimes the word is shortened simply to "weevil".

Bomb — A thick-walled container, usually made of steel, that is used to receive samples of oil or gas under pressure or to measure and record the pressure at a point in the well. (see "bottom hole pressure").

BOPD — Barrels of oil per day.

Bottom hole — Descriptive of the lowest or deepest part of a well.

Bottom hole Choke — A device with a restricted opening placed in the lower end of the tubing to control the rate of liquid or gas flow to the surface. (see "choke").

Bottom hole Pressure — The pressure in a well at a point opposite the production formation, usually recorded by a bottom hole pressure instrument popularly called a "bomb". The "bomb" houses a precision gage and is usually lowered on a wireline. (see "bomb").

Braided line — See stranded line.

Bridge — An obstruction (usually sand) that blocks movement of equipment and/or pressure in a well.

Brine — Water that has a large quantity of salt, especially sodium chloride, dissolved in it; "salt water".

Bull Plug — A threaded nipple with a rounded, closed end used to close a wellhead or flowline opening or close off the end of a line.

Bumper Jar — See jar.

—C—

Caliper Log — A record of the diameter of the wellbore or the internal diameter of tubular goods. The log indicates undue enlargement of the wellbore due to caving, washout, or other causes.

Casing — Steel pipe placed in an oil or gas well as drilling progresses. The function of casing is to prevent the wall of the hole from caving during drilling, provide control of the well if it tries to blow out, and limit oil or gas production to the zone perforated or open.

Casinghead — A heavy, steel, flanged fitting that connects to the surface string of casing and provides a housing for the slips and packing assemblies by which intermediate strings of casing are suspended and the annulus sealed off.

Casing Pressure — The pressure built up in the annular space between casing strings, casing and tubing, or casing and drill pipe.

Cement Dump Bailer — A cylindrical container with a valve that is used to release small batches of cement downhole in a remedial cementing operating or for other special purposes.

Cement Plug — A portion of cement placed at some point in the wellbore to effect a sealing action.

CFR 250 — Rules and regulations promulgated by the Minerals Management Service that govern oil and gas operations in waters under Federal control. CFR is an abbreviation for Code of Federal Regulations.

Check Valve — A valve that permits flow in one direction only.

Choke — A type of orifice installed in a line to restrict flow and control the rate of production. Surface chokes are a part of the "Christmas tree" and contain a choke nipple, or bean, with a small-diameter bore (an orifice) that serves to restrict the flow. Also, chokes are used to control the rate of flow of the drilling mud out of the hole when the well is closed in with the blowout preventer and a "kick" is being circulated out of the hole. (See adjustable choke, bottom-hole choke, and positive choke).

Christmas Tree — The valves, pressure gages, and chokes assembled at the top of a well to control the flow of oil and gas after the well has been completed.

Clean Out — To remove sand, scale, and other deposits from the well to restore or increase production.

Close In — To temporarily shut in a well that is capable of producing oil or gas; to close the blowout preventers on a well that is being drilled in order to control a "kick". The blowout preventers close off the annulus so that pressure from below cannot flow to the surface.

Closed-in Pressure — (See "formation pressure").

Collar — A coupling device used to join two lengths of pipe. A combination collar is a coupling with left-hand threads in one end and right-hand threads in the other. Sometimes drill collars are called simply collars.

Collar Locator — A logging device that detects casing or tubing collars for depth-correlation purposes. It may be operated mechanically or electrically to produce a log showing the location of each casing collar or coupling in a well. When properly interpreted, this log provides an accurate way to measure depths in a well.

—D—

Dead Weight Tester — A device using calibrated weights to measure pressure accurately.

Dead Well — A well that has ceased to produce oil or gas, either temporarily or permanently; a well that has suffered a kick or blowout and been killed.

Differential — A difference in quantity or degree between two measurements or units (as the pressure differential across a choke — i.e., the pressure on one side of the choke compared with the pressure on the other side). (see differential pressure).

Differential Pressure — The difference between two fluid pressures (e.g., the difference between the pressure in a reservoir and the pressure in a wellbore drilled into the reservoir; the difference in pressure on either side of a restriction in a pipeline; the difference between the atmospheric pressure at sea level and at 10,000 ft., etc.) (see differential).

Driller's Report — A record kept on the rig for each tour to show the footage drilled, drilling-fluid tests, bit record, and all important occurrences during that tour.

Dummy — A blank tool installed in a side pocket gas lift mandrel landing nipple and/or sliding sleeve.

—E—

Elbow — A fitting that allows two pipes or nipples to be joined together at an angle of less than 180°, usually 90° or 45°. (Slang term for elbow is "ell").

Elevation — Measurement of a well location or a plane on a drilling well above a specified datum, usually sea level.

External Upset — An extra-thick wall at the threaded end of drill pipe or tubing. Externally upset pipe does not have a uniform outside diameter throughout its length but is enlarged at each end.

—F—

Fish — Any object left in the wellbore during drilling or workover operations that must be recovered before work can proceed. v: To recover an object (fish) left in a wellbore during drilling or workover.

Fishing Neck — A groove in the top of many wireline tools to allow other tools to clamp the tool and remove it from the well.

Fishing Tool — A tool designed to recover equipment (lost or left) from the well.

Flag — A piece of cloth, rope, or nylon strand used to mark a stranded wire line when swabbing, bailing, etc.

Floor Blocks and Pulleys — An arrangement of equipment for routing or directing the wireline into the well.

Fluid — A substance that flows. A fluid yields to any force tending to change its shape. *Both liquids and gases are fluids.*

Formation Pressure — The pressure exerted by fluids in a formation, recorded in the hole at the level of the formation with the well shut in. Formation pressure may also be termed "reservoir pressure", or "shut-in bottom-hole pressure".

Friction — The resistance to movement created when two surfaces are in contact. When friction is present heat is produced. (Sometimes referred to as "drag" in wireline operations).

—G—

Gas — A fluid substance that completely fills any container in which it is confined and whose volume is dependent on the size of and pressure exerted upon the container. A gas is readily compressible.

Gas-Input Well — A well into which gas is injected for return to the reservoir in a pressure-maintenance or secondary-recovery program.

Gas Lift — The process of producing fluid from a well by means of gas injected down the well through tubing or through the tubing-casing annulus. Injected gas aerates the fluid to make it exert less pressure than the formation pressure. Consequently, the higher formation pressure forces the fluid out of the wellbore.

Gas-Lift Mandrel — A device run in the tubing string into which a gas-lift valve is installed. The two most common types of mandrels are the conventional mandrel and the sidepocket mandrel. The gas-lift valve is installed in the conventional gas-lift mandrel as the tubing is placed in the well. To replace or repair the valve the tubing string must be pulled. On the other hand, the gas-lift valve is installed and removed from the sidepocket mandrel by wireline while the mandrel is still in the well, eliminating the need to pull the tubing to repair or replace the gas-lift valves.

Gas-Lift Valve — A device installed on the tubing string of a gas-lift well that is sensitive to tubing and casing pressures, which cause the valve to open and close. The functioning of the valve is to allow gas to be injected into the fluid in the tubing in order to cause the fluid to rise to the surface.

Gas Well — A well that primarily produces gas.

Gage (Gauge) Pressure — The pressure exerted on the interior walls of a vessel by the fluid contained in the vessel as indicated by the device capable of measuring this pressure (a pressure gage). Absolute pressure being equal to gage pressure plus atmospheric pressure. (psig - pounds per square inch gage).

Gin Pole — A pole used with hoisting equipment to lift heavy loads.

Go-Devil — A device dropped or pumped down the well, usually through drill pipe or tubing.

Go in the Hole — To lower drill pipe, tubing, work-over tools, or other devices into the wellbore.

Gravel Pack — A mass of very fine gravel that is placed around a slotted liner. Gravel packing is a method of well completion in which a slotted or perforated liner is placed in the well and surrounded by a very fine-mesh gravel.

Guy Line — A cable attached to a workover rig, lubricator, etc. and anchored in the ground to provide stability.

Guy-Line Anchor — A buried weight or anchor to which a guy line is tied to provide line stability.

—H—

Hydrate — A hydrocarbon and water compound which forms in gas gathering, compression, and transmission facilities or well bores under reduced temperature and pressure. In appearance, hydrates resemble snow or ice, and can plug equipment.

Hydraulic — Operated, moved, or effected by liquid (usually water).

Hydrogen Sulfide — A gaseous compound, commonly known by its chemical formula, H_2S, frequently found in oil and gas reservoirs. It has a distinctive "rotten-egg" odor. It is extremely poisonous and corrosive and quickly deadens the olfactory nerve so that its odor is no longer a warning signal.

—I—

Impression Block — A block with lead or another relatively soft material on the bottom. The block may be made up on drill pipe, tubing, or wireline at the surface, run into a well, and allowed to rest on a tool or other object that has been lost in the well. On retrieval to the surface, an idea of the size, shape and position of the "fish" is obtained from an examination of the impression left in the lead. This helps in selecting the appropriate fishing tools.

Injection Well — A well into which fluid is pumped to increase reservoir pressure or to push reservoir fluids toward a producing well.

—J—

Jackup Vessel — An offshore drilling or well servicing structure with tubular or derrick legs that can be moved vertically to support the deck and hull.

Jar — n. A percussion tool that operates on a mechanical or hydraulic principle and is designed to deliver a heavy hammer blow to objects in the borehole to which it is attached. Jars are used for such purposes as freeing stuck objects in the hole in fishing operations or imparting a jarring motion to stuck tools for the purpose of freeing them. The design of the jar often permits blows to be delivered in either a downward or upward direction, with control being effected at the surface.

Jar — v. To apply a heavy upward or downward blow to the drill stem, or a heavy upward or downward blow to wireline tools, by use of a jar.

Jar Accelerator — A hydraulic tool used in conjunction with a jar. The accelerator is made up in the fishing string above the jar and serves to increase the magnitude of the jarring blow delivered to the fish.

Junk — n. The metal debris lost in a hole. Junk may be lost tools, pieces of wire, or any relatively small objects that impedes activity to the extent that it must be fished out of the hole. v. To abandon a project (as a well with mechanical problems that cannot be corrected).

—K—

Kick — An unintended entry of water, gas, oil, or other formation fluid into the wellbore. A kick occurs because the pressure exerted by the column of fluid is not great enough to overcome the pressure exerted by the fluids in the formation drilled. If prompt and proper action is not taken, a blowout may occur.

Knuckle Joint — A deflection tool, placed above the tools in the work string, that has a ball and socket arrangement, which allows the tool to be deflected at an angle. A knuckle joint is sometimes useful in fishing operations because it allows the fishing tool to be deflected to the side of the hole where a fish may have come to rest.

—L—

Lubricator — A specially fabricated length of pipe with union connectors and bleed-off valves that is temporarily placed above a valve on top of the casing or tubing head. Lubricators afford a method of sealing off pressure yet still allow the passage of a device, usually on a wireline, or substance into the well without having to kill the well.

—M—

Mast — A portable derrick capable of being erected as a unit, as distinguished from a standard derrick which cannot be raised to a working position as a unit. Used for well drilling or well work-over.

Master Valve — A large valve located on the Christmas tree. It is used to open or close the well.

Measuring Device — A special reel for solid wireline used to take depth measurements in a well. A calibrated wheel, roller assembly, and counter measures the footage of wire line as it is lowered into the well. It is also used to measure the footage of wire line as it is pulled from the well.

Mechanical — The distribution of power by mechanical devices (chains, sprockets, clutches, and shafts).

MMS — Abbreviation for Minerals Management Service, the Federal Government agency responsible for enforcement of rules pertaining to the drilling, completion and operation of oil and gas wells on the Outer Continental Shelf (offshore) and federal lands onshore. (Formally United States Geological Survey — USGS).

Multiple Completion — An equipment arrangement for producing two or more oil or gas formations from one wellbore. Multiple completions may use parallel tubing strings, each packed off from the other to prevent commingling of the production from different formations, or concentric strings, each packed off from the other, for the same purpose.

—N—

Needle Valve — A valve having tapered gate that rests in a tapered orifice for extremely fine regulation of flow.

Nipple — A tubular pipe fitting threaded on both ends, usually less than 12 inches long.

No-Go — A landing nipple specially machined with a reduced inside diameter designed to prevent passage of larger equipment past a particular point in the well.

—O—

Oil Saver — A packing arrangement that seals around a wire line to prevent leakage and waste of gas, oil, or water (as when swabbing or reworking a well). It may be operated mechanically or hydraulically.

Operating Pressure — The pressure at which a flow line or system is operated at any given time. May also be used as wellhead flowing pressure.

OSHA — Occupational Safety and Health Administration, a regulatory agency under the U.S. Labor Department.

Overshot — A fishing tool attached to a wireline tool string, tubing, rods, or drill pipe that is lowered over the outside of a "fish" lost or stuck in the wellbore. A friction device in the overshot, usually a basket or a spiral grapple, firmly grips the fish allowing it to be pulled from the hole.

—P—

Packer — Downhole equipment consisting essentially of a sealing device, a holding or setting device, and an inside passage for fluids. It is used to block the flow of fluids through the annular space between the tubing and the wall of the wellbore (or between tubing and casing) by sealing off the space between them.

Packing — A material used in the stuffing box of a valve or between flange joints to maintain a leakproof seal.

Packing Gland — The metal part that compresses and holds the packing in place in a stuffing box.

Pack Off — To place a packer in the wellbore and activate it such that it forms a seal between the tubing and casing.

Paraffin — A hydrocarbon having the formula $C_nH_{2n}+2$ (e.g., methane, CH_4; etc.). Heavier paraffin hydrocarbons (i.e., those of $C_{18}H_{38}$ and heavier) form a waxlike substance that is called paraffin. These heavier paraffins often accumulate on the walls of tubing and other production equipment, restricting or stopping the flow of oil.

Paraffin Inhibitor — A chemical that, when injected into the production string prevents or minimizes paraffin deposition.

Paraffin Scraper — Any tool used to remove paraffin from inside tubular goods.

Prime Mover — The source of power for a pump or other device, usually internal combustion engines or electric motors.

PSIA — Pounds per square inch absolute. (see absolute pressure).

PSIG — Pounds per square inch gage. (see gage pressure).

pH (pH value) — A unit to measure the degree of acidity or alkalinity of a substance. A neutral solution (as pure water) has a pH of 7; acid solutions are less than 7; basic, or alkaline, solutions are above 7.

Plug and Abandon (P & A) — To place a cement plug or plugs in a dry hole or uneconomic producing well to abandon it.

Plug back — To place cement or other material at or near the bottom of a well to exclude bottom water or to perform another operation such as side tracking or producing from another depth. It may also be used to denote the setting of a mechanical plug by wire line, tubing, or drill pipe.

Positive Choke — A choke with a fixed orifice size. To change the size of the orifice the choke bean or choke nipple is changed.

Pressure Gage — An instrument for measuring fluid pressure. A pressure gage usually registers the difference between atmospheric pressure and the pressure of the fluid being measured by indicating the effect of such pressure on a measuring element (as a column of liquid, a bourdon tube, a weighted piston, a diaphragm, or other pressure-sensitive device).

Pressure Gradient — Uniform change in pressure from one point to another. For example, the pressure gradient of a column of pure water is about 0.433 psi/ft of vertical elevation.

Pulling Flange — The flange, or neck, on a pulling tool. (see fishing neck).

—Q—

Quick Union — A union with coarse threads that employs an O-Ring seal for a quick lock.

—R—

Ram — The closing and sealing component on a blowout preventer. Rams are of three types: blind, pipe, and shear. Pipe rams, when closed, have a configuration such that they seal around the pipe; shear rams cut through drill pipe and then form a seal. Blind rams seal on each other with no pipe in the hole.

Ram Blowout Preventer — A blowout preventer that uses rams to seal off pressure in the well bore; also called a ram preventer.

Reel System — A circular drum and assorted mechanical equipment used to spool wireline.

Remote Reading Gage — An instrument capable of providing indications of pressure, vacuum, voltage, etc., at a point remote from the place that such indications are actually taken.

Reservoir Pressure — The pressure that exists in an oil, gas, or water bearing formation or reservoir.

Rockwell Hardness — A numerical value which expresses the resistance of a material to indentation with a small diamond point or a one-sixteenth inch diameter ball. The higher the number the harder the material.

Rope Falls — Block and tackle arrangements to assist in wireline operation equipment placement.

—S—

Safety Valve — An automatic valve designed to close or open when an abnormal condition exists.

Scale — A deposit formed by chemical action, or temperature and pressure changes on surfaces in contact with water — i.e., calcium carbonate, magnesium carbonate, calcium sulfate.

Scraper — Any device (as a line scraper, paraffin scraper, etc.) that is used to remove deposits (as scale or paraffin) from tubing, casing, rods, or flow lines.

Shut-in Bottom-Hole Pressure — The pressure existing at the bottom of a well when the well is completely closed. (see formation pressure).

Side-Door Mandrel — (see gas-lift mandrel).

Side-Pocket Mandrel — (see gas-lift mandrel).

Sinker Bar — A heavy weight or bar placed in the wireline tool string. The bar adds weight so that the tool will lower properly through the well fluids.

Slick Line — (see "solid wire line").

Sliding-Sleeve Nipple — A special device placed in a string of tubing which can be operated by a wireline tool to open or close orifices (openings) to permit circulation between the tubing and annulus. It may also be used to open or shut off production from various intervals in a well.

Solid Wire Line — A special wire line of very strong steel, usually 0.066 to 0.092 inch in diameter. (Sometimes referred to as "slick line").

Stainless Steel — (1) Non-magnetic (austenitic): An alloy of over 16 percent chromium, over 7 percent nickel, and iron. Manganese can be used to partially replace nickel. (2) Magnetic ferritic): An alloy of over 11 percent chromium and iron.

Stuffing Box — A packing gland that may be adjusted to allow a wireline or polished rod to operate through it while containing well pressure and well fluids.

Surface equipment — Equipment used above ground level.

Subsurface equipment — Equipment put into a well to perform an operation below the wellhead.

Surface Pressure — Pressure measured at the wellhead.

Surface Safety Valve — A device mounted in the wellhead assembly that serves to stop the flow of fluids from the well should damage occur downstream of the well.

Swab — n. A rubber-faced, hollow cylinder mounted on a hollow mandrel with a pin joint on the upper end to connect to the swab line. A check valve installed on the lower end of the swab and opening upward may be used to unload a well (remove fluids) when the well ceases to flow.

Swab — v. To operate a swab on a wire line to bring well fluids to the surface when the well does not flow naturally. This is a temporary operation to determine whether or not the well will flow. If the well does not flow after being swabbed, it is necessary to install a pump or other permanent lifting device to bring oil to the surface.

Swage — A tool for straightening damaged or collapsed tubing in a well.

Swage Nipple — A pipe fitting having external threads of one size on one end and a different size on the other end.

—T—

Temperature Gradient — The rate of change of temperature with displacement in a given direction. As the depth of a well increases, so does the temperature; this phenomenon is known as the temperature gradient. It varies according to geographical location and geological formations encountered.

Temperature Survey — An operation to determine temperatures at various depths in the wellbore. This survey is used to determine the height of cement behind the casing when there is doubt as to the height, to find the location of water influx into the wellbore, and for other reasons. Wire line equipment may be used.

TD — Total depth. The maximum depth drilled.

Tubular goods — Any kind of pipe. Oilfield tubular goods include tubing, casing, drill pipe, and line pipe.

—U—

Union — A coupling device used to connect pipe without the need to rotate the pipe. The makeup is accomplished by a flanged, threaded collar on the union.

USGS — Abbreviation for United States Geological Survey (see MMS).

—V—

Vacuum — Theoretically, a space absolutely devoid of all matter and exerting zero pressure. However, vacuum is commonly used to describe a condition that exists in a system when pressure is reduced below atmospheric pressure.

Valve — A device used to control the rate of flow in a line, to open or shut off a line completely, or to serve as an automatic or semiautomatic safety device. Those valves that find extensive usage in the oil industry include the gate valve, plug valve, globe valve, needle valve, check valve, and relief valve, (also called a safety valve).

Viscosity — A measure of the resistance of a liquid to flow.

—W—

Weight Indicator — An instrument that shows the weight suspended from a wireline or hook.

Wellhead — The equipment used to maintain surface control of a well. It is formed of the casinghead, tubing head, and appropriate valves. The Christmas tree is installed on top of the tubing head.

Well Servicing — Maintenance and repair work performed on an oil or gas well to improve or maintain the production from a formation already producing in the well. Usually, it involves repairs to the pump, rods, gas-lift valves, tubing, packers, etc. Also refers to people who do this work, such as a well servicing company.

Wire Line — (see solid wire line).

Wire Rope — A rope composed of steel wires twisted into strands that are twisted around a central core. Wire rope is sometimes referred to as "wireline" or "cable".

Wireline Cutting Tool — A special device, usually run on a solid wire line, that is used to cut another wire line that may be stuck in a well.

Wireline Preventer — A manually operated, ram type blowout preventer that is especially adapted for closure around a wire line.

Wireline Spear — A special fishing tool fitted with prongs to catch and recover wire line that has been broken and left in a well.

Wireline Wiper — A flexible, rubber device used to wipe off mud, oil, or other liquid from a wire line as it is pulled out of a well.

Working Pressure — The maximum pressure at which an item is to be used at a specified temperature.

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