Baker Hughes INTEQ

Oil Field Familiarization

Training Guide

80912 Rev. B May 1996

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Preface

At Baker Hughes INTEQ, we have always prided ourselves on our people and their level of professionalism, experience, responsiveness and adaptability at the wellsite. It is at the wellsite, where time, money and effective operations separate INTEQ from its competitors. To keep this competitive edge, the company has a system for training, development and professional advancement for operations-based field personnel - takes our good track record and makes it even better.

The training development program (IN-FACTS) provides a standardized career development path which utilizes a progression of both formal and hands-on learning, to turn potential into competitive advantage. It is the tool that enables field personnel to embark on a successful career within Baker Hughes INTEQ, Baker Hughes, and the oil industry.

The training system is structured to provide an easily understood, orderly flow of learning experiences. These may or may not be in the same speciality, and allow our people to either concentrate in one area or to branch out into other disciplines. Movement through career progression is determined by industry experience and their skills and knowledge, which can be acquired through rigsite work and a variety of formal and informal training programs.

The training programs are modular and are composed of formal course work, self-paced learning packages and on-the-job training.

Overview of the Course

All field personnel complete the Oil Field Familiarization school, which provides a general overview of the petroleum industry, with emphasis on drilling technology, completion technology, petroleum geology and wellsite safety. Upon completion of this initial module, a probationary period provides new hires with further hands-on field training, safety and survival training (and certification where appropriate), and an opportunity to perform other job assignments.

There is a continuous source of education and training that promotes individual confidence and self-motivation in employees, and ultimately produces management professionals with true “hands-on” field experience.

The Oil Field Familiarization Training Guide will introduce petroleum geology and the petroleum industry. Learn and Enjoy!

Customer Relations

During your first weeks with Baker Hughes INTEQ you will be very involved in learning the techniques of wellbore construction, completion operations and wellsite routines. While these duties always require total concentration and accuracy, there is yet another skill to be developed and maintained throughout your career -- that of good customer relations.

Although basic rig configuration is generally the same, you may sometimes be working with only a few people at a given wellsite or there may be more than 100, depending on the size of operations. In addition to the Baker Hughes INTEQ personnel and drilling crew, there can be many other service companies' personnel to support the drilling operations. Great effort is required to coordinate all the people and functions, and everyone there has an important, specialized job. You can see, therefore, why a "successful well" is very dependent on good communication among all wellsite personnel and good relationships with the client.

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Chapter 1

Introduction

The first oil wells, called “wildcats,” drilled to rather shallow depths of approximately 1000 feet. Hole depth was limited because of primitive drilling equipment and the limited technology. The first types of rigs called “cable tool rigs” gave way to the rotary rigs in the 1900’s which immediately improved drilling techniques and permitted greater depths.

The use of drilling fluids were discovered by a drilling accident. When the advantages of drilling fluids were recognized, they became an essential part of the planned drilling program. At first the mud was used primarily to clean, cool and lubricate the bit as it drilled through formations. The fluid also removed the formation cuttings from the hole by circulating the mud using surface pumps. In those early years (early 1900s) well analysis consisted primarily of examining the mud and returns for visible signs of oil and by using the sense of smell to detect the odor of hydrocarbons.

Around 1930 it was realized that mud and cuttings could be correlated to well depth and analyzed to supply more specific data about the formation. The first significant advance in drill returns analysis was made in 1938 when a method was developed to determine the amount of oil in the drilling fluid by centrifuging, and to determine the relative amount of gas in the drilling fluid by using a hot-wire bridge circuit. This early instrumentation was borrowed from the mining industry where it had been used to detect combustible and explosive gases in mine shafts. As these methods pertained to the drilling fluid only, surface logging was originally known as “mud logging.” (Today, Baker Hughes INTEQ refers to mud logging as a segment of “formation evaluation.”)

The predictions of oil and gas accumulations made with these methods were at first very erratic, partly because of the lack of experience and partly because these methods did not furnish sufficient information. Around 1943, a method was developed for systematically analyzing and examining the cuttings for oil and gas. The additional information obtained by this procedure made surface logging an effective and important hydrocarbon detection and evaluation method.

Surface logging is not the only evaluation method used as drilling is in progress. In the 1970’s another method to monitor the formation before any changes (due to mud properties) have occurred was introduced. The ability to “log” the formation while drilling, termed “Measurement-While-Drilling” or “Logging-While-Drilling (MWD/LWD) provides petrophysical and directional information about the formation soon after the drill bit penetrated the formation. For this reason it is an essential evaluation method.

Wireline logging and drillstem testing (DST) evaluate the formation after changes have occurred. When used with surface logging and MWD, they can provide an overall evaluation of the formation properties.

Chapter **2**

Petroleum Geology & Oil Field Fluids

Geology is so fundamental to the petroleum industry that a knowledge of its basic principles is desirable for all persons associated in any way with the industry. This section gives a brief outline of the geological processes, the origin and accumulation of petroleum, and how these concepts are related to the production of oil and gas.

Petroleum geology is based on the observation and utilization of many other sciences. The basic principle that “the present is the key to the past” is the concept the processes which have acted on the earth in the past are very similar to or the same as those operating today. The geologist's conclusions or deductions are derived by:

- Observing the results of the earth's history and processes
- Reconstructing events that give rise to certain formations and their arrangement
- Predicting where oil accumulations might occur

The accumulation of oil and gas into a commercial deposit requires the presence of a “trap” consisting of a source rock, a reservoir rock, a seal (or cap rock), and a three dimensional closure. The source rock is a formation structurally and chronologically placed to provide a source of petroleum for the reservoir. The reservoir rock is a formation which is usually much more extensive than the hydrocarbon (petroleum) deposit that has been localized by the trap. Below the oil or gas accumulation, the reservoir is almost always filled with water. The qualification of an economic oil pool is that it must contain enough oil or gas to make extraction profitable, must exceed a minimum porosity and permeability and have a minimum thickness, depending on local conditions. Igneous and metamorphic rocks rarely contain oil or gas. Sedimentary rocks are more important to petroleum geology since it is here that most oil and gas accumulations occur because of their greater porosity and permeability.

Sedimentary Rocks

Sedimentary rocks are deposited by water, wind, or ice. They may be hard and compact or soft, loose and friable. Older sedimentary rocks have been compacted by weight of overlying sediments and cemented by minerals carried by ground water so that they become consolidated sedimentary rocks. Connate water is the water present in pores and cracks in the rocks.

Sedimentary rocks are made up of the following:

- Clastic material, or fragments, composed mainly of broken and worn particles of preexisting minerals, rocks and/or shells, which are carried to the site of deposition by moving streams, waves, wind or glaciers
- Chemical precipitates formed in place by evaporation at the surface or by crystallization of dissolved salts within the sediment
- Organic or biogenic debris such as shells or plant remains accumulated inplace; for example, a coral reef or peat

A simple classification of sedimentary rocks is shown in Figure 2-1.

Clastic	**Chemical**		**Organic**	**Other**
	Carbonate	**Evaporite**		
Conglomerate	Limestone	Gypsum	Peat	Chert
Sandstone	Dolomite	Anhydrite	Coal	
Siltstone		Salt	Diatomite	
Shale		Potash	Limestone	
Limestone				

Figure 2-1: Sedimentary Rocks

Figure 2-2 illustrates a modern sedimentary rock classification based on a tetrahedron. Carbonate, clay, quartz and chert are placed at the corners. This figure also depicts one side of this tetrahedron so that some of the variations between shale, sandstone, and limestone can be seen. For example, starting from shale and going toward limestone, increasing amounts of lime will produce calcareous shale, grading into argillaceous (shaly) limestone, then to pure limestone. Similarly on the other two edges, it is shown how the changes occur from shale to sandstone and from sandstone to limestone. The other three sides show similar variations with chert replacing one of the other constituents.

Sediments are deposited under a variety of conditions or environments, both on land and at sea. Clastics (conglomerates, breccia, sandstone, siltstone, limestone and shale) may be deposited under any of the following environments:

- continental aeolian - deposited by the wind on land
- transitional deltaic - deposited in the mouth of a river
- coastal interdeltaic - deposited on the coast between deltas
- marine - deposited in the oceans (lagoonal, backreef, estuarine)

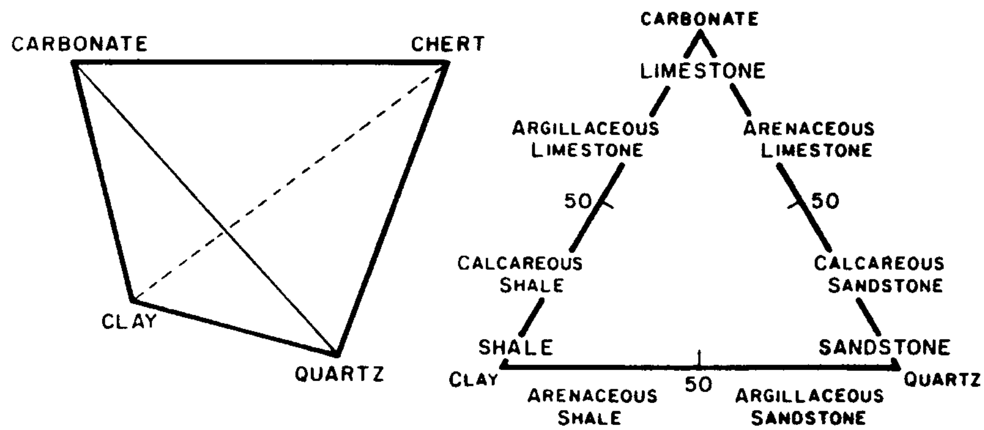

Figure 2-2: Fundamental Tetrahedron for Classifying Sedimentary Rocks

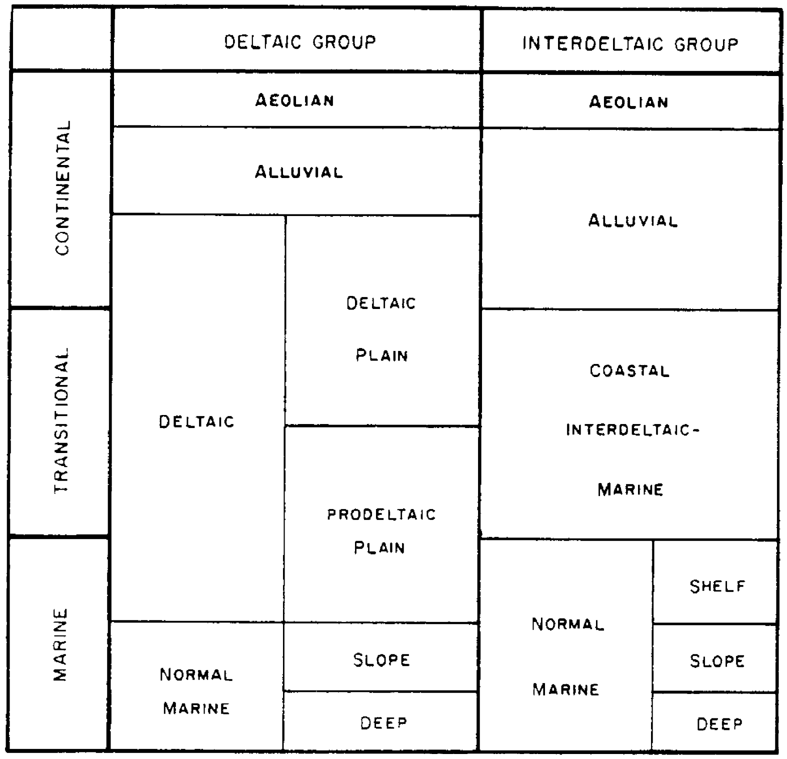

Figure 2-3: Depositional Environments

A simplified classification of sedimentary environments is shown in Figure 2-3. Although a line is shown separating the classifications, there is no sharp line of demarcation; they grade into one other. For example, alluvial grades into upper deltaic plain, or lower deltaic plain into prodeltaic plain, which, in turn, grades into normal marine. The map in Figure 2-4 shows the extent of various recent depositional environments in the area between the Mississippi River and the Rio Grande. The outer part of the deltaic sediments extends off the shoreline and grades into the normal marine deposits. The crosshatched area in the southwest section on the map is an area of sand dunes and is aeolian.

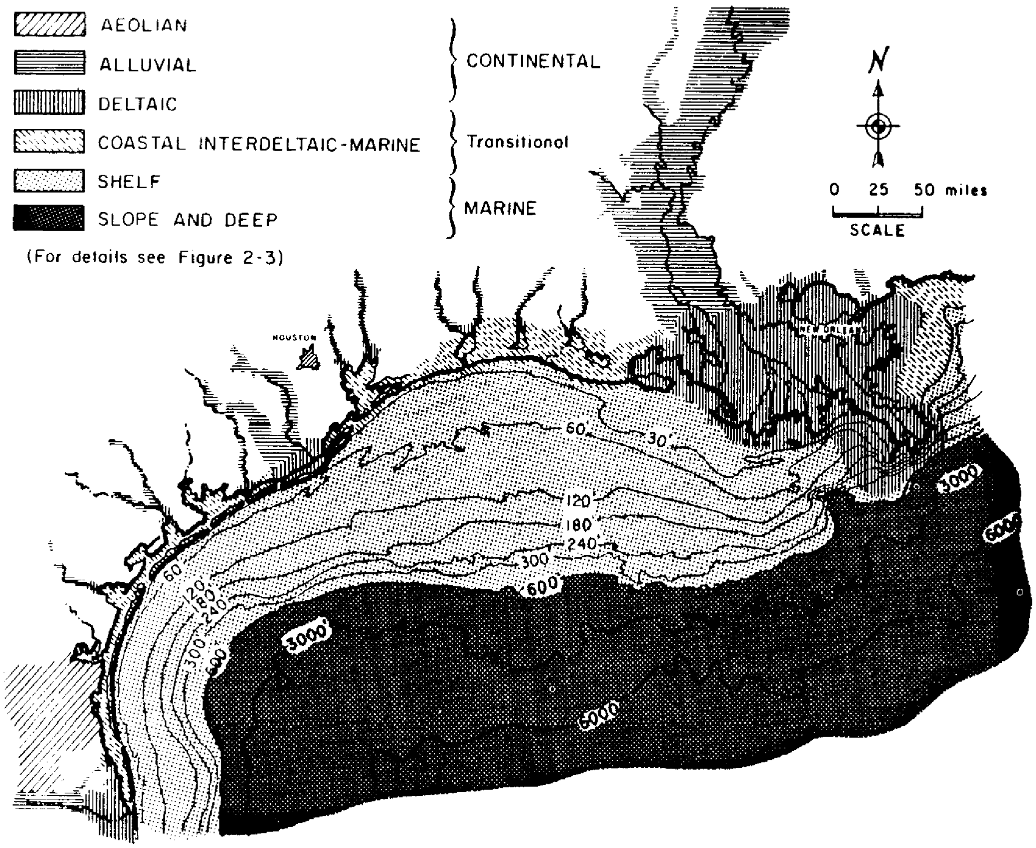

Figure 2-4: Recent Depositional Environments of Northwestern Gulf of Mexico

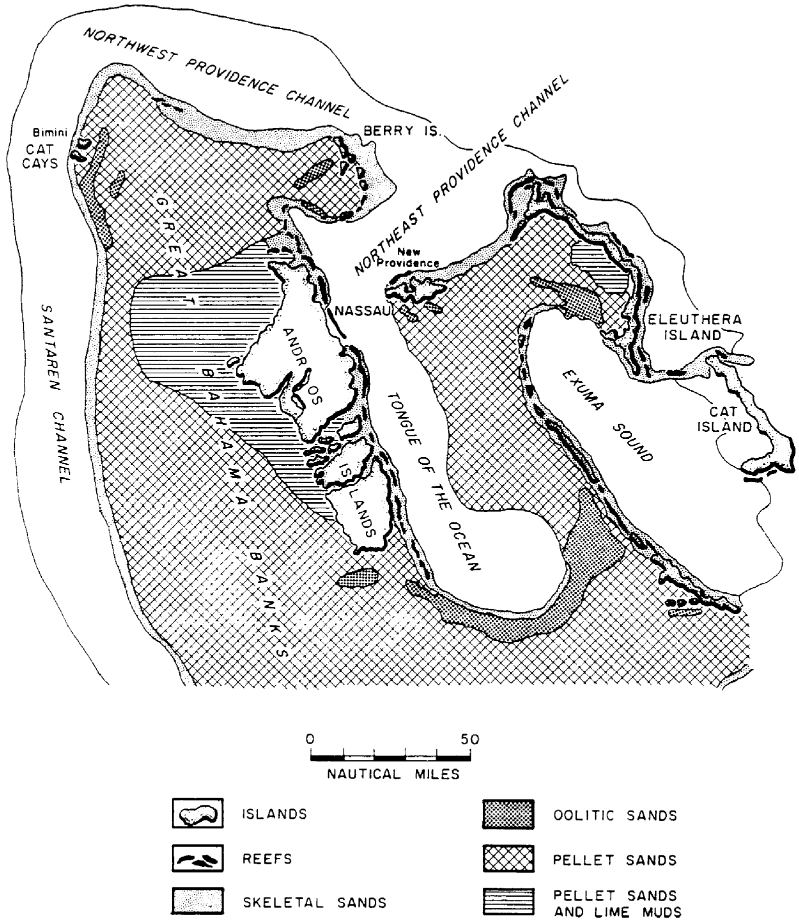

Figure 2-5: Distribution of Surface Sediments of the Bahamas Bank

The distribution of surface sediments in the Bahamas Banks is shown in Figure 2-5. Note that the skeletal sands are along the margin, whereas over the bank interiors the sediments are mainly pellet sand or pellet sands and lime muds. Oolitic sands occur only locally where tidal currents are active; for example, at the south end of the deep water tongue of the ocean and at the north end of Exuma Sound. Discontinuous reef barriers occur mainly on the windward northeast of land areas. Many ancient carbonate deposits show the same sedimentation and faunal (animal life) characteristics as these recent sediments.

A large portion of the sedimentary rocks in the geologic column were probably deposited in transitional-marine environments (relatively shallow water on the continental shelf). This includes the deltaic-marine sediments and many carbonate (limestone and dolomite) sequences which contain large petroleum accumulations throughout the world.

Geological Structures

Sedimentary rocks are deposited in essentially horizontal layers or shallow slopes called strata or beds. Most rock layers are not strong enough to withstand the forces which they are subjected to and are deformed. A common kind of deformation is the buckling of the layers into folds which are the most common structures in present and ancient mountain chains. They range in size from small wrinkles to great arches and troughs many miles across. The upfolds or arches are called anticlines; the downfolds or troughs called synclines. Folds have many forms, a few which are shown in Figure 2-6. They may be symmetrical with similar flank dips on both limbs or asymmetrical where one limb is steeper than the other. The ends of anticlines and synclines usually plunge, and a very short anticline -- the crest of which plunges in opposite directions from a high point is called a dome. Many domes are uplifted by an intrusive core, such as the salt domes of the Gulf Coast in the United States, Northern Germany, and elsewhere.

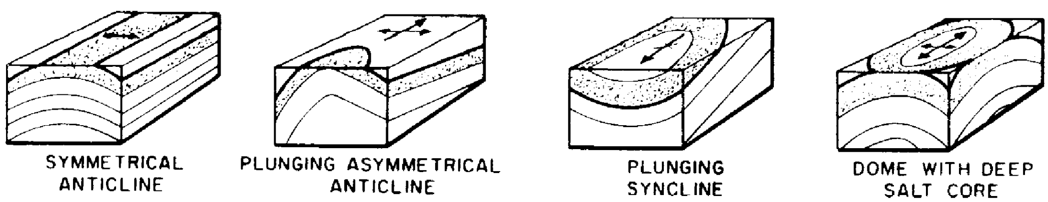

Figure 2-6: Simple Kinds of Folds

Earth Movements

Nearly all rocks are fractured to some extent during earth movement forming cracks, called joints. If the rock layers on one side of the fracture have moved in relation to the other side, the fracture is called a fault. Displacement on a fault may range from only a few inches to many thousands of feet, even miles in some cases such as along the San Andreas fault in California. Faults are described according to their present attitude by various names. There are four simple classifications of faults, as shown in Figure 2-7:

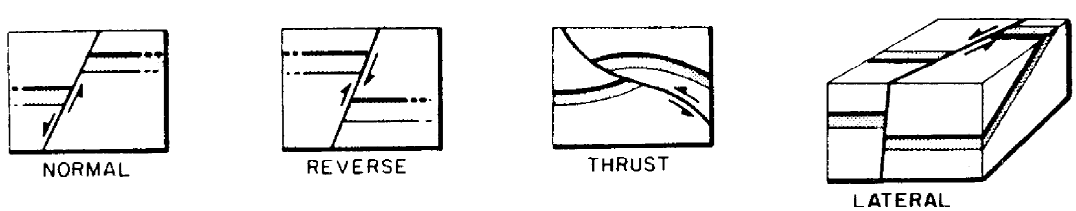

Figure 2-7: Simple Kinds of Faults

These terms reflect the relative movement of the adjacent block with\ respect to one another. Movement is upward or downward in the case of normal and reverse faults, but horizontal in thrust and lateral faults. Faults may also have a combination of vertical and horizontal movements.

Rotational faults and upthrusts (Figure 2-8) are variations of normal and reverse faulting. They are important to the petroleum geologist since they have very important effects upon the location of oil and gas accumulations as compared with the accumulations associated with normal and thrust faults.

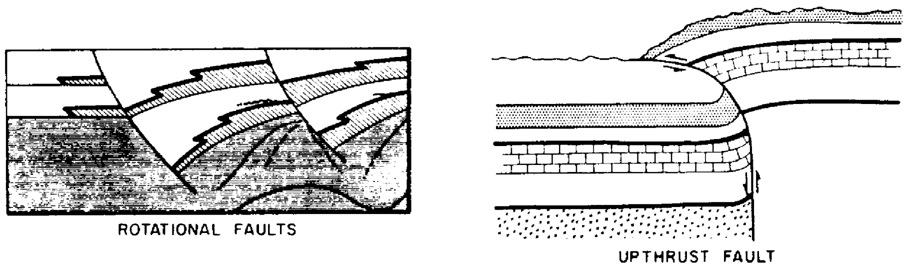

Figure 2-8: Cross-Section Showing Rotational and Upthrust Faults

Another result of earth movement is to erode or prevent the deposition of part of a series of sediments which are present elsewhere. A buried erosion surface is called an unconformity. There are two general kinds as shown in Figure 2-9. A disconformity, where the beds above and below the surface of unconformity are parallel, as shown in the left diagram; and an angular unconformity, where the beds above unconformity transgress the eroded edges of folded and tilted beds below, as shown in the other two diagrams. Earth movements are most important to the subject of petroleum geology because they produce barriers which trap a large proportion of petroleum accumulations.

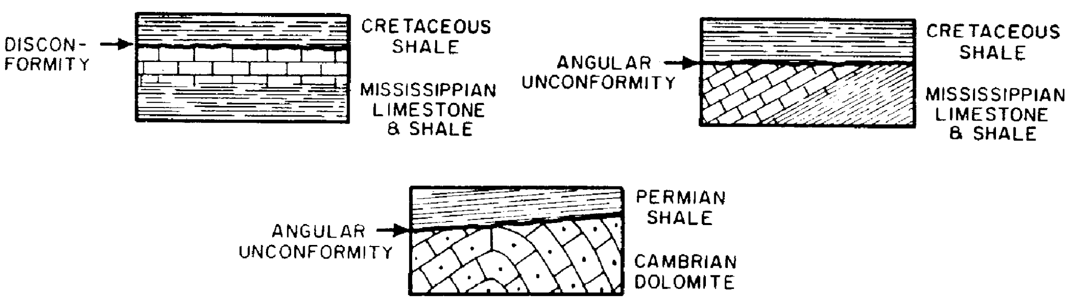

Figure 2-9: Unconformities

Application Of Geological Concepts

In the early days of oil exploration, the most successful oil-finding method was to drill in the vicinity of oil seeps (where oil was actually present on the surface of the ground). Many of the great oil fields of the world owe their discovery in part to the presence of oil seeps. Seeps are of two general kinds: (1) seepage along fractures and (2) seepage updip (Figure 2-10). The diagram on the right shows a seep at the outcrop of a reservoir bed. Such seeps may be active where oil or gas is still slowly flowing. In other cases, the sands near the surface are completely sealed with asphalt from the oil and the seep is no longer active. Seepage from fractures and faults is very common and may be oil or gas or sometimes mud as in the mud volcanos of Trinidad and Russia. Active seep are present along the anticlinal crest in the La Paz Field, Venezuela, and the Kirkuk, Iraq.

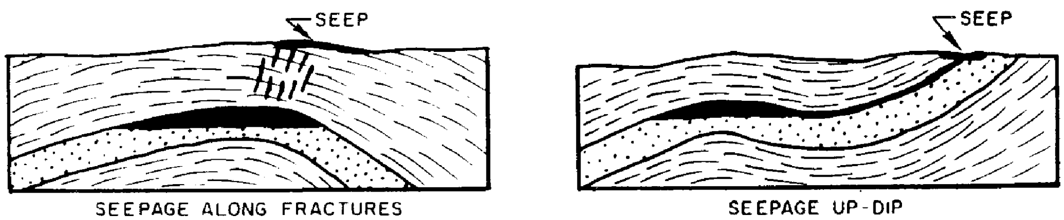

Figure 2-10: Schematic Cross-Section of Seeps

Geophysical Exploration

By 1920 it was obvious that anticlinal folding was only one of a number of geological factors controlling oil and gas accumulation and that much more was required than from surface mapping alone. At this time, geophysical methods were being developed; first was the torsion balance, and later came the seismograph which enabled subsurface structures to be deduced. The seismic method, the most important in today's predrilling exploration, uses the transit time of sound waves (the time required for a sound pulse to travel a fixed distance between a transmitter and receiver) generated by explosion. These transit times depend on the nature of the rocks, particularly their density. The transit time is the time for a wave reflected from the subsurface to arrive at the surface (Figure 2-11). Under favorable conditions, geologic beds may be mapped quite accurately to create subsurface contour maps of structure and possible reservoir locations.

Other geophysical methods include the gravimeter and magnetometer which make use of the physical properties of the rocks to find favorable structural conditions for petroleum accumulation. In early Gulf Coast exploration, salt domes were located by gravity anomalies. In remote land locations, gravity surveying can be done from the air and is therefore much cheaper than seismic surveying.

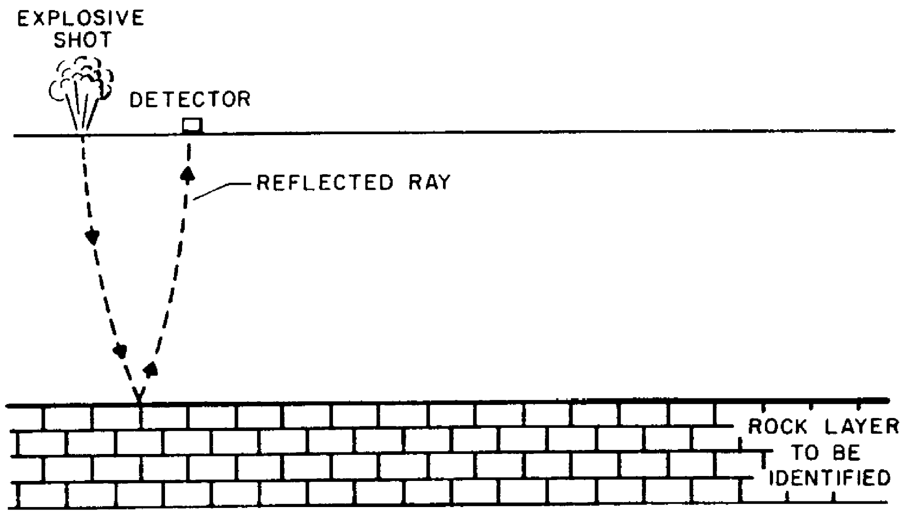

Figure 2-11: Reflected Seismic Waves

Surface Exploration

Surface mapping and photogeology, i.e., aerial photos and photogrammetric “stereo pairs” using Earth Resources Satellite (ERSAT) scans, are used extensively for lithological and structural determinations. Another type of surface exploration is geochemical prospecting (a recent technique based on the supposition that some hydrocarbons in an oil accumulation) migrate vertically to the surface directly over the oil field. There are at least five general methods of geochemical prospecting:

- Analysis of free hydrocarbons gases in the pore spaces of the soil
- Analysis of gaseous hydrocarbons absorbed on the soil particles or on subsurface rock samples
- Fluorescence of soil samples presumably due to the presence of high molecular weight hydrocarbons
- Analysis for bacteria that thrive on certain kinds of hydrocarbons
- Radioactive scintillometer surveys

Geochemical prospecting, as a direct indicator of oil, is limited because hydrocarbons do not migrate directly upward from an accumulation. Migration occurs along faulted and fractured zones and through more permeable beds such as glacial drift or continental deposits. Water in sands overlying accumulations can redirect any upward migration. Consequently, surface indications may be useful in defining oil, gas or barren regions, but they cannot pinpoint an accumulation.

Seeps and natural asphalts give surface evidence of oil or gas that has migrated from its original accumulation. Outcrops, if not weathered, contain traces of hydrocarbons that are indicative of the oil potential of the sediment.

Subsurface Exploration

The methods and techniques used in the study of subsurface geology have developed since the 1920s. Today, more oil and gas discoveries are credited to subsurface geology studies than to any other technique.

Data is determined by the following:

- Distribution of organic carbon. It is generally accepted that shales need more than 0.5% organic carbon to yield commercial oil. The organic carbon content of Devonian shales in the oil-producing region of the Russian platform is 1.6% and in the barren regions 0.5%. In the richest oil region, it ranges from 0.5 to over 5%.
- Gas analysis of mud and cuttings. Sediments in the immediate vicinity of petroleum accumulations have much higher gas yields compared to those away from accumulations. Mapping the vertical and areal distribution of gas and related light hydrocarbons can show the sedimentary sections more apt to contain commercial accumulations (Figure 2-12).

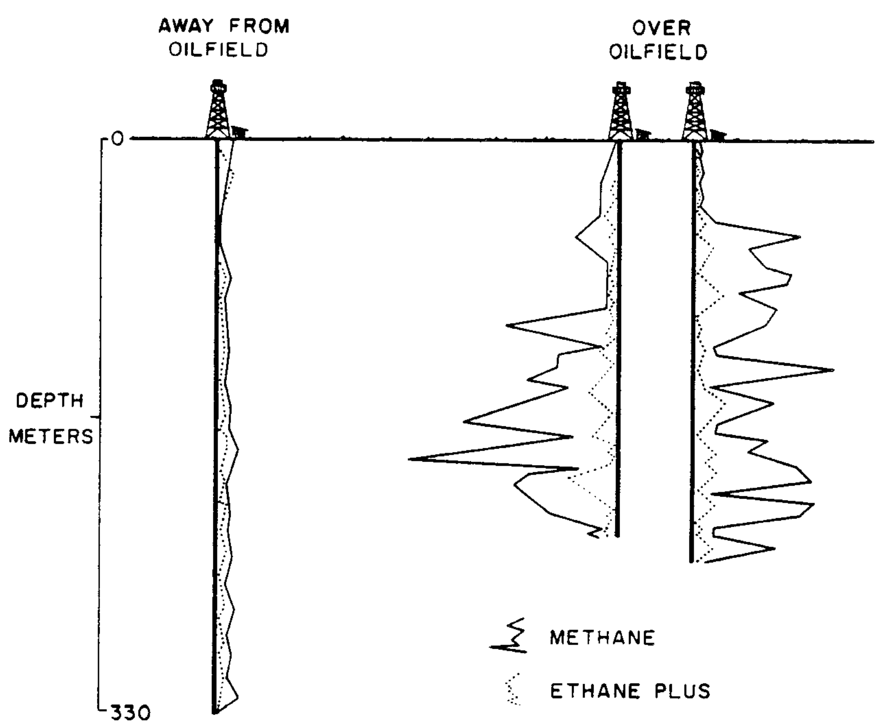

Figure 2-12: Diffusion of Hydrocarbons

- Geochemical temperature facies. The disseminated organic matter of sedimentary rocks, “kerogen”, is insoluble in acids and organic solvents. The organic matter initially deposited with unconsolidated sediments is not kerogen but a precursor that is converted into kerogen during diagenesis. Kerogen in shales changes color from yellow to orange-brown to black through the subsurface temperature range from about 100^{o}F (38^{o}C) to 500^{o}F (260^{o}C). The mature orange-brown range yields oil and wet gas (Figure 2-13). Color changes may be anomalous in carbonates because recrystallization blackens organic matter.

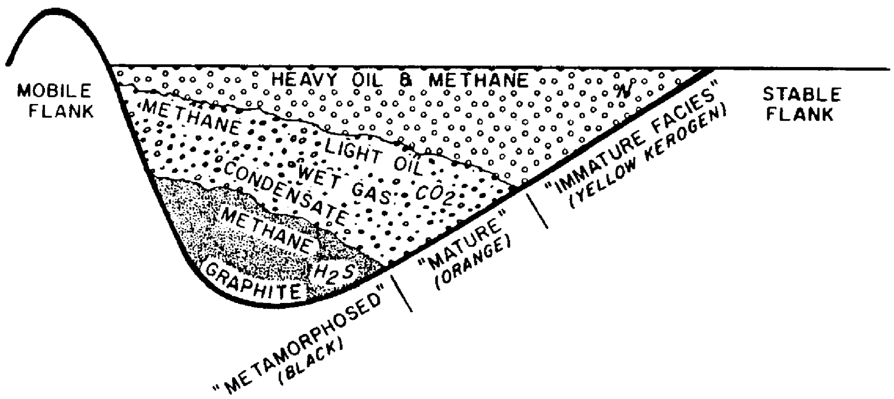

Figure 2-13: Geochemical Temperature Facies in a Typical Basin

- Gasoline and gas in cuttings. The analysis of C1-C4 (gas) And C4-C7 (gasoline) hydrocarbons in cuttings shows the subsurface range in which oil is being generated and wet gas is phasing out. Wet gas is natural gas dissolved in heavier hydrocarbons where the liquid vapors amount to more than 300 gallons of propane, butane and other liquid hydrocarbons per 1000 ft^3 of gas.

- Heavy hydrocarbons, C15+, in outcrops, cores and cuttings. Source rock quality and type (gas, oil or non-generating) can be evaluated from C15+ analysis on unwatered cuttings cores, outcrops.

- Kerogen analysis. With increasing depth, analysis of carbon, hydrogen, and oxygen in mineral-free kerogen from cuttings or cores indicates horizons which hydrocarbons can be generated from a reversal in hydrogen content. The threshold of intense oil generation usually occurs below the accumulation zone (Figure 2-14).

- Vitrinite reflectance. Metamorphism of sediments causes disseminated vitrinite particles to harden and reflect light better. Reflectance (Ro) ranges from 0.5 to 1.2 in oil zones. Recycling of vitrinite particles and oxidation of particles gives anomalous readings.

- Wireline log correlation.
- Lithology (rock type) and environments of deposition from cores.

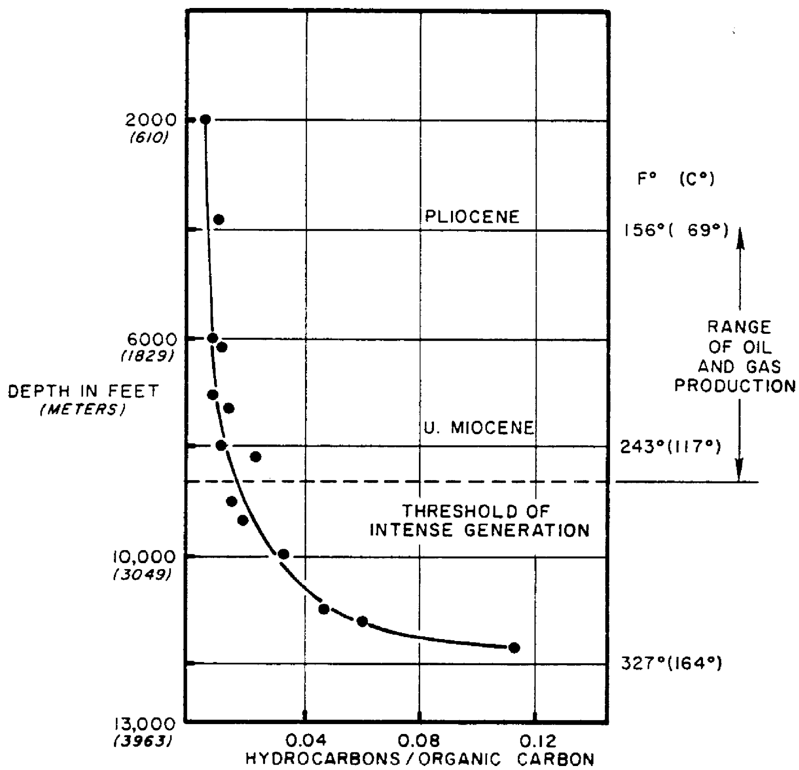

Figure 2-14: Generation of Hydrocarbons in Los Angeles Basin

Exploration Applications

Considering the exploration possibilities, the following procedures are conducted whenever possible:

- Basin Evaluation. Determinations are made of organic carbon, C15+ hydrocarbons, kerogen type and color, plus vitrinite reflectance on unweathered outcrops or shallow cores of prospective exposed horizons. In offshore area, analysis is made on C1-C7 hydrocarbons in surface cores. All seeps onshore and offshore are analyzed.
- Wildcat Wells. Analysis is made for two or more of the following on cuttings or cores: Gas and gasoline, C15+ hydrocarbons, kerogen type and color, C,H,O elemental analysis, vitrinite reflectance. Any subsurface water samples are analyzed for hydrocarbons. In permafrost, or deep ocean areas, hydrocarbon hydrates (crystalline compounds in which the ice

lattice of H_2O expands to form cages that contain gas molecules) are monitored.

- Development Areas. Correlation of crude oils with their source rocks and with seeps is done with detailed gas chromatography and mass spectrometry of hydrocarbon groups. Untested horizons are analyzed like wildcat wells.
- Generalizations. A commercial petroleum accumulation requires a hydrocarbon source, a structure or trap with impermeable cover, and good reservoir porosity and permeability. Geochemical techniques define the first requirement by indicating whether there is enough organic matter of the right type for commercial accumulations, and by defining the stage of organic maturation in the sediments penetrated. Well cuttings, core analysis and wireline log interpretation define the other requirement.

The information is used to prepare many kinds of maps and cross-sections. Contour maps are used to show geologic structure on numerous correlation markers. Other contour maps may show fault attitude and intersections with beds and other faults, as well as porosity and permeability variations. Various types of maps may show variations in the characteristics of the rocks and the structural arrangement such as old shorelines, pinchouts, or truncation of beds.

Maps give only a plan view, so it is necessary to supplement them with vertical cross-sections. These are of various kinds; they may show fault structures as in Figure 2-15, or they may be designed to show detail of one sort or another for just one small interval. For example, the section Figure 2-16 shows the effect of a pinchout to the north by comparing the thickness between correlation marker A and B.

Conceptual Models of Exploration

A conceptual model in petroleum geology is an idea, developed from available data, to illustrate how a geological area is structured, what it looks like, and where petroleum accumulations are likely to occur.

The prediction of both sand trends and pore space distribution is important in all phases of exploiting sandstone reservoirs. It is quite disconcerting during primary development to drill a well a few hundred feet from a good producer only to find the objective sand absent. The best way to appreciate the value of environmental concepts is to consider a few examples of their applications in oil field development problems. The following paragraph gives one example.

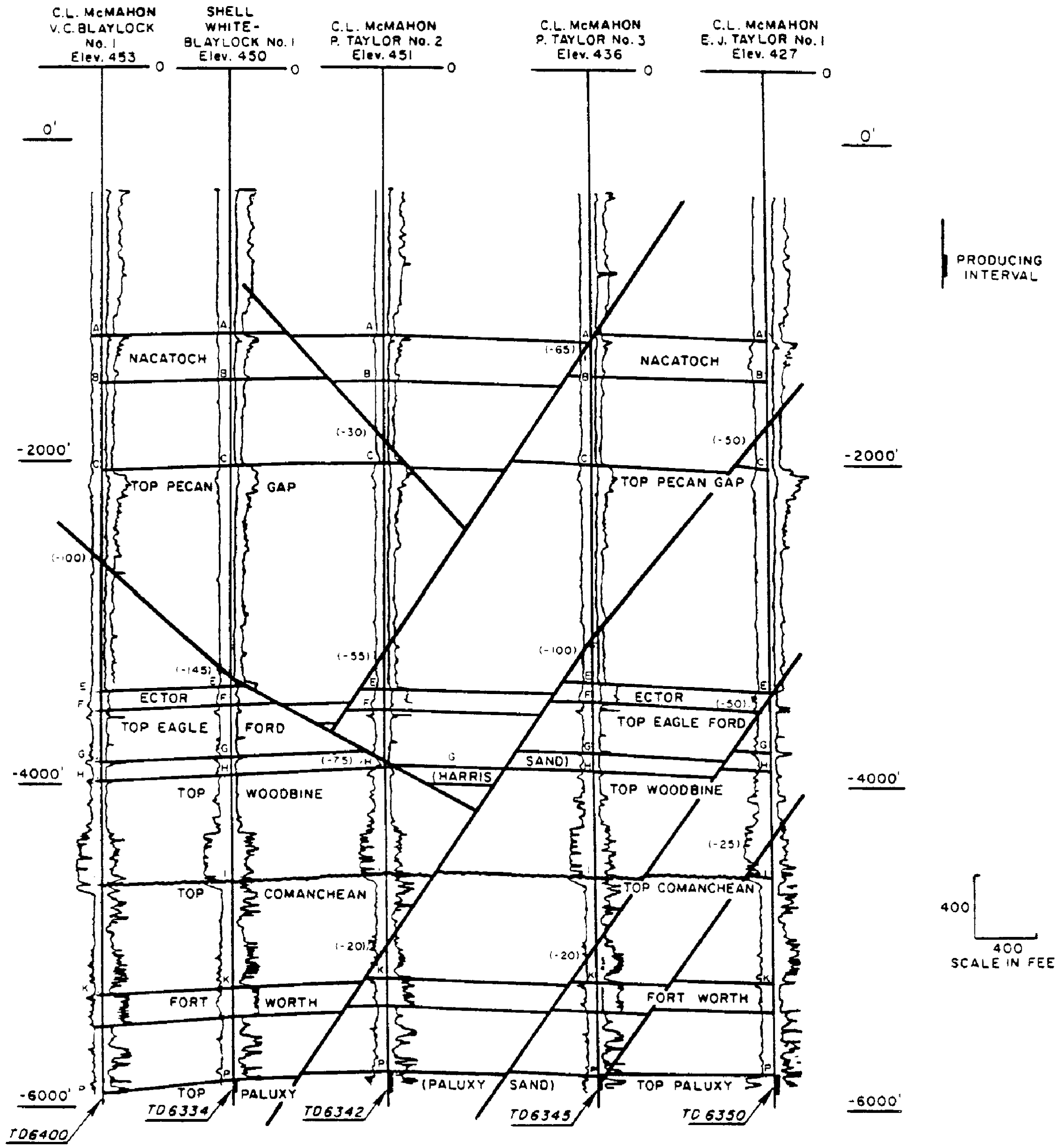

Figure 2-15: Cross-Section Illustrating Fault Pattern, Quitman Field, Texas

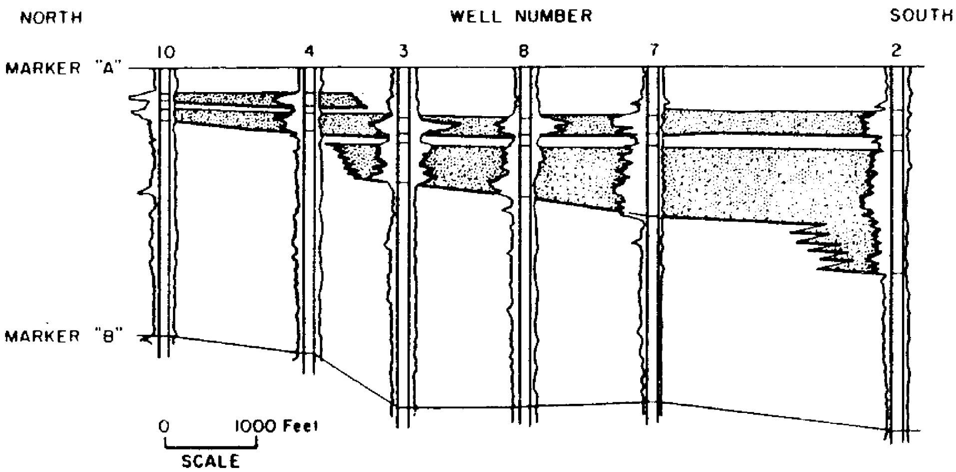

Figure 2-16: Sand Pinchout

An environmental study of the Aux Vases sandstone in an oil field in Illinois showed that the reservoir is a composite of two types of sand bodies (shoreline and tidal channel deposits) having distinctly different trends and distribution as well as different characteristic properties and boundary relations. The tidal channel sandstones were shown to have cut down into the shoreline sandstones. A rework of several pairs of wells indicated that fluid communication was poor or absent between the two types of sand.

Petroleum Accumulations

For petroleum to accumulate, there must be (1) a source of oil and gas; (2) a reservoir rock (a porous bed which is permeable enough to permit the oil and gas to flow through it); and (3) a trap (a barrier to fluid flow so that accumulation can occur against it). Most knowledge has been obtained from experience and observation, but certain generalizations can be made:

- Petroleum originates from organic matter
- To become commercial, the hydrocarbons must be concentrated
- Petroleum reservoirs primarily occur in sedimentary rocks

Origin of Petroleum

The following discussion presents a general overview of one theory for the origin of oil. Oil and gas originate from organic matter in sedimentary rocks. Dead vegetation in the absence of oxygen ceases to decompose. It accumulates in the soil as humus and as deposits of peat in bogs and swamps. Peat buried beneath a cover of clays and sands becomes compacted as the temperature, weight and pressure of the cover increase, and water and gases are driven off. The residue, ever richer in carbon, becomes coal.

In the sea, a similar process takes place. Of the marine life that is eternally falling slowly to the bottom of the sea, vast quantities of it are eaten, some is oxidized, but a portion of the microscopic animal and plant life escapes destruction and is entombed in the mud on the seafloor. The organic debris collects at the bottom and is buried within a growing buildup of sands, clays and more debris until the thickness of sediment attains thousands of feet. Bacteria takes oxygen from the trapped organic residues, breaking them down molecule-by-molecule into substances rich in carbon and hydrogen, and the extreme weight and pressure of the mass compacts the clays into hard shales.

The generation of hydrocarbons from the source material depends primarily on the temperature to which the organic material is subjected. Hydrocarbon generation appears to be negligible at temperatures less than 150^oF (65^oC) in the subsurface and reaches a maximum within the range of 225^o to 350^oF (107^o and 176^oC), the “hydrocarbon window”. Increasing temperatures convert the heavy hydrocarbons into lighter ones and ultimately to gas. However, at temperatures above 500^oF (260^oC), the organic material is carbonized and destroyed as a source material. Consequently, if source beds become too deeply buried no hydrocarbons will be produced.

Migration

After generation, the dispersed hydrocarbons in the fine-grained source rocks must be concentrated by migration to a reservoir. Compaction of the source beds by the weight of the overlying rocks provides the driving force necessary to expel the hydrocarbons and to move them throughout the more porous beds or fractures to regions of lower pressure (which normally means a shallower depth.) Gravity separation of gas, oil and water takes place in reservoir rocks which are usually water-saturated. Consequently, petroleum is forever trying to rise until it is trapped or escapes at the earth's surface. Vertical migration via faults and fractures has led to many of the large oil accumulations, such as that found at shallow depths in the Believer District, Venezuela, and northern Iraq. In other cases, such as the Khurais field in Arabia, migration over relatively long distances has had to take place by movement up-dip in a porous reservoir bed until a trap was encountered.

Primary Migration: Primary migration of petroleum from source to reservoir is caused by the movement of water, which carries oil out of the compacting sediments. When the source muds are deposited they contain 70 to 80 percent water. The remainder is solids, such as clay materials, carbonate particles or fine-grained silica. As they build up to great thickness in sedimentary basins, water is squeezed out by the weight of the overlying sediments. Under normal hydrostatic pressure (approximately 0.446 psi/ft), the clays lose porosity and the pore diameters shrink, as shown in Figure 2-17.

Depth		Clay Porosity	Clay Pore Diameter
(Meters)	(Feet)	(Percent)	(Nanometers)*
610	2,000	27	----
2,000	6,560	15	10.0
3,000	9,840	9	5.0
4,000	13,120	6	2.5
5,000	16,400	4	1.5
(*10^{-9}m)			

Figure 2-17: Changes During Normal Compaction of Shales

Fluids tend to move toward the lowest potential energy. Initially this is upward, but as compaction progresses there is lateral as well as vertical movement. The lateral movement results primarily from the tendency of the flat clay mineral particles to lie horizontally as they are compressed. This reduces the vertical permeability of the compacting sediments. In addition, the long continuous sands on the edges of basins orient fluid movement laterally as burial progresses, as illustrated in Figure 2-18. The migration of oil from source to reservoir is as follows:

1. Water flows toward the lowest potential energy.
2. Clays often have abnormal pressure because they are slow to release water.
3. Avenues of migration during basin compaction are:
    - sandstones
    - unconformities
    - fracture-fault systems
    - biohermal reefs

The mechanism by which oil migrates is uncertain, but most likely it is in solution. The solubility of the lighter petroleum hydrocarbons in water is adequate to account for known oil accumulations. When this solution reaches the reservoir, the change in environment may cause coagulation of the hydrocarbons to form discrete oil particles. The heavier hydrocarbons may travel as more soluble non-hydrocarbons and form hydrocarbons in the permeable beds. Another mechanism is simply the squeezing out of oil particles due to the structuring of water. Ordered water exists 2 to 4 nanometers (1 nm = 10^{-9}m = 10 angstrom) from a clay mineral surface. Hydrocarbon molecules range up to 2 nm with asphaltenes to 5 nm in size. Since pore openings are less than 10 nm in shales deeper than 2000 m, the hydrocarbons are squeezed out (Figure 2-19). Near-surface fluid migration may be restricted in areas of permafrost or offshore basins where solid methane hydrates may form in sediments.

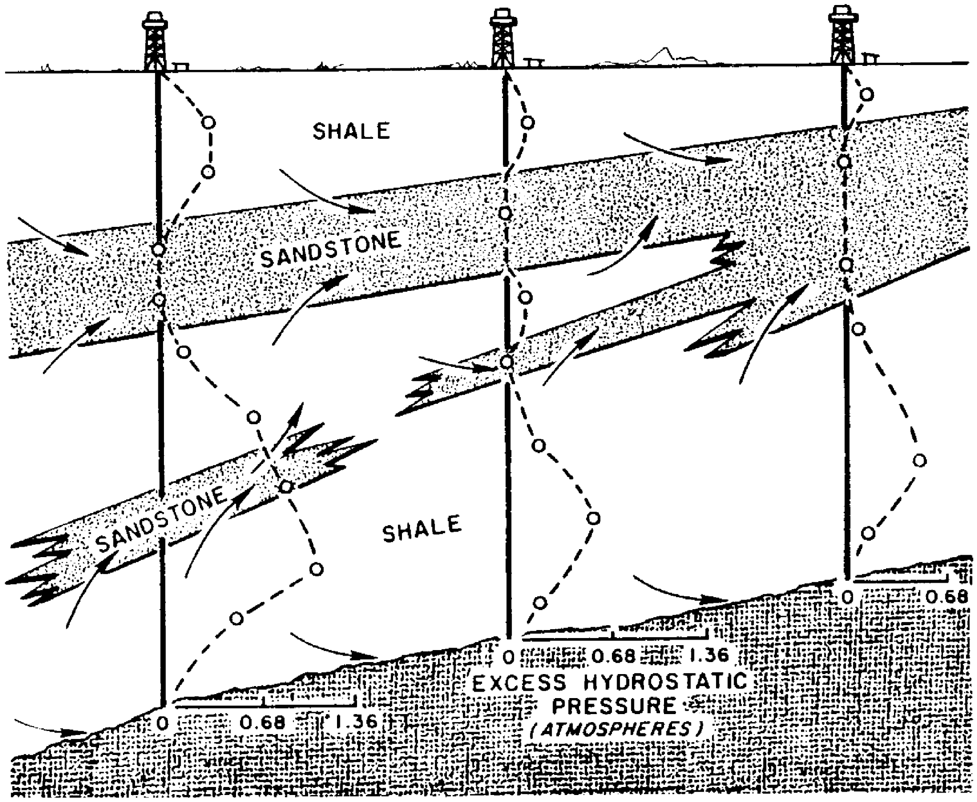

Figure 2-18: Fluid Flow During Compaction

Secondary Migration: In secondary migration, the oil droplets are moved about within the reservoir to form pools. Secondary migration can include a second step during which crustal movements of the earth shift the position of the pool within the reservoir rock.

The position of the accumulating pool is affected by several, sometimes conflicting, factors. Buoyancy causes oil to seek the highest permeable part of the reservoir; capillary forces direct the oil into the coarsest-grained portion first, and into successively finer-grained portions later. Any permeability barriers in the reservoir channel the oil into a somewhat random distribution. Oil accumulations in carbonate rock are often erratic because part of the original void spaces have been plugged by minerals introduced from water solutions after rock is formed.

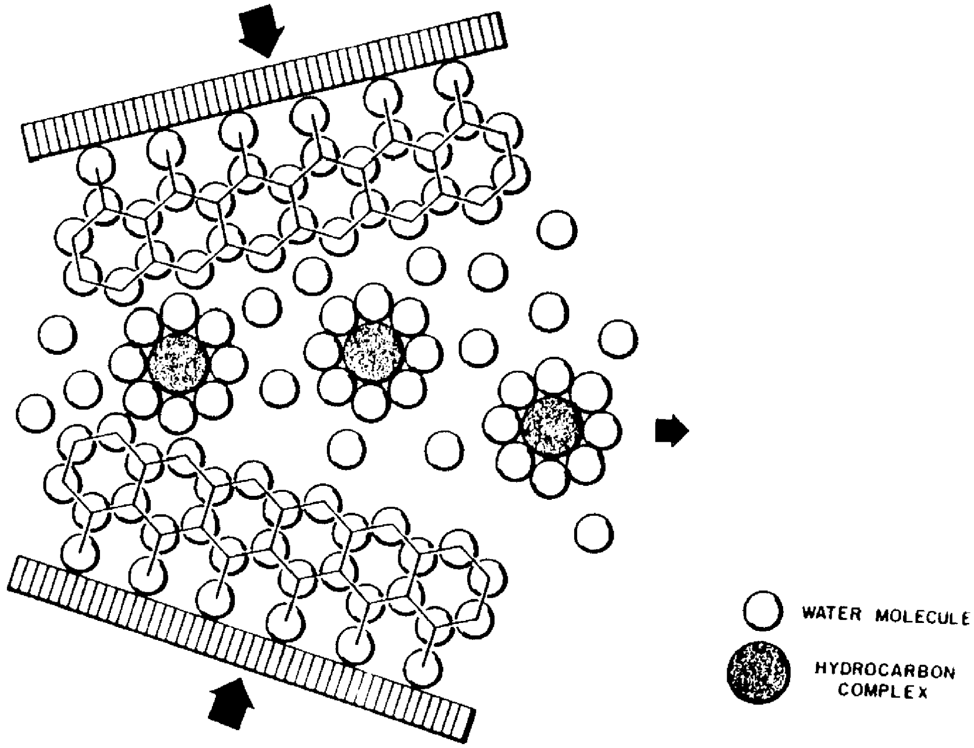

Figure 2-19: Migration Induced by Fixed Water

In large sand bodies, barriers formed by thin layers of dense shale may hold the oil at various levels. When crustal movements of the earth occur, oil pools are shifted away from the place in which they originally accumulated. Faults sometimes cut through reservoirs, destroying parts of the pools or shift them to different depths. Uplift and erosion bring the pools near the surface where the lighter hydrocarbons evaporate. Fracturing of the cap rock allows oil to migrate vertically to much shallower depth. Wherever differential pressures exist and permeable openings provide a path, petroleum will move.

Reservoir Rocks

A petroleum reservoir is a rock capable of containing gas, oil or water. To be commercially productive it must have sufficient thickness, areal extent, and pore space to contain an appreciable volume of hydrocarbons, and must yield the contained fluids at a satisfactory rate when the reservoir is penetrated by a well. Sandstones and carbonates are the most common reservoir rocks. The porosity characteristic of a rock may be primary, such as the intergranular porosity of sandstone, or it may be secondary due to chemical or physical changes such as dolomitization, solution channels, or fracturing. Porosity may be adversely affected by compaction and cementation. The distribution of petroleum reservoirs and the trend of pore spaces therein are the result of numerous natural processes.

Sandstones: In sandstones, porosity is controlled primarily by sorting (that is, by mixing the various sizes of grains), cementation and, to a lesser extent, by the way the grains are packed together. Porosity is at a maximum when grains are spherical and all one size, but becomes progressively less as the grains are more angular because such grains pack together more closely. Figure 2-20 shows two ways of packing spherical grains. The one on the left is open (cubic) packing where the porosity is about 48 percent. The close (rhombohedral) packing on the right has porosity of only about 26 percent because the grains are packed into smaller space.

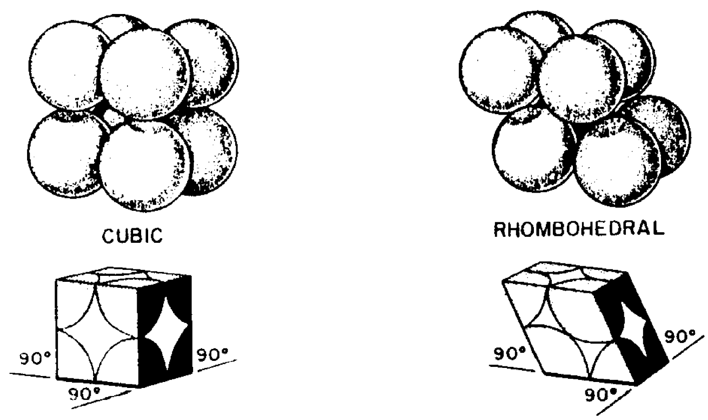

Figure 2-20: Unit Cells of Cubic and Rhombohedral Packing

Artifically mixed clean sand has measured porosities of about 43 percent for extremely well-sorted sands, irrespective of grain size, decreasing to about 25 percent for very poorly sorted medium-to coarse-grained sands, while the very fine-grained sands still have over 30 percent porosity. Figure 2-21 summarizes diagrammatically some of the processes controlling pore size distribution in sandstones.

The ease with which fluid moves through the interconnected pore spaces of a rock denotes the degree of permeability. In 1856 Henry d'Arcy, a French engineer, devised a means of measuring the permeability of porous rocks. Numerical expressions of permeability are measured in “darcies” (d). A rock has a permeability of one darcy (1 d) when 1cc of a fluid of 1 centipoise viscosity flows through a 1 cm cube (1 cm x 1cm^2) of rock in 1 second, under a pressure gradient of 1 atmosphere.

Note: *Note: The viscosity of water at 68^{o}F = 1 centipoise (cp)*

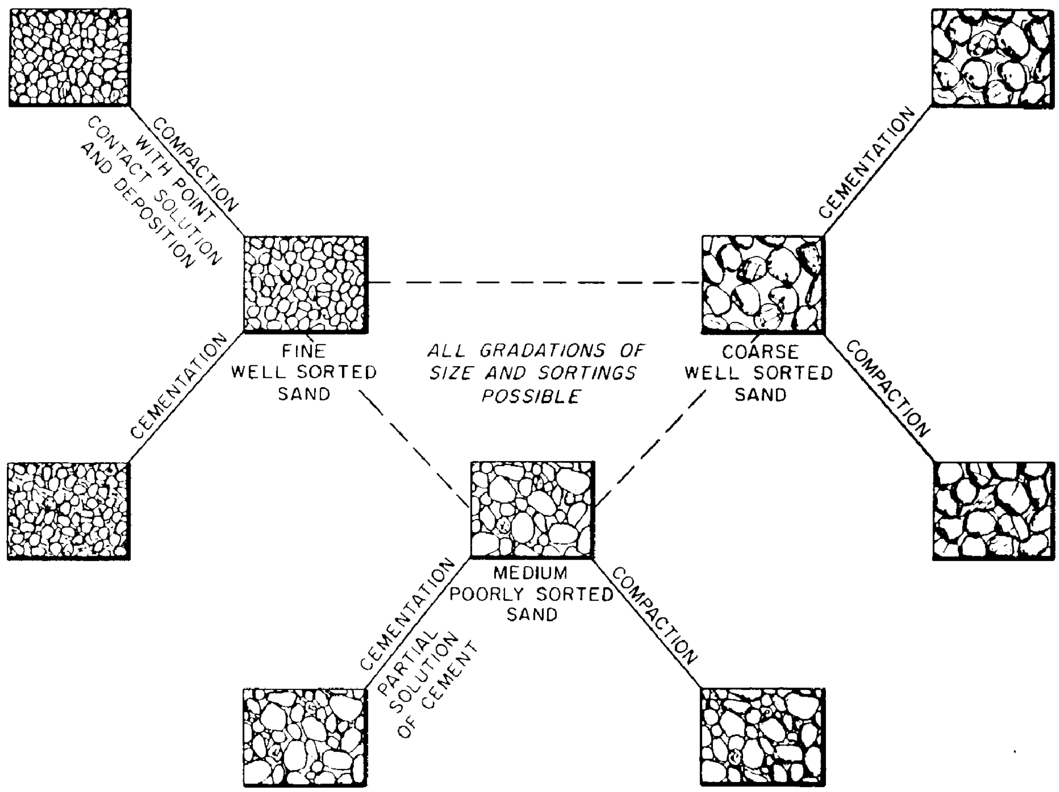

Figure 2-21: Some Processes Controlling Pore Size Distribution in Sandstones

Because most reservoir rocks have average permeabilities considerably less than one darcy, the usual measurement is millidarcies (md, thousandths of a darcy). Permeability of a highly porous, well-sorted sand varies from 475 md for a coarse-grained sand to about 5 md for a very fine-grained sand. Permeability may decrease for a coarse-grained sand to about 10 md if it is very poorly sorted.

Compaction by weight of the overlying sediments squeezes the sand grains closer together. At greater depths, it may crush and fracture the grains. The result is smaller pores and therefore lower porosity, but more importantly, a decrease in permeability. Thus, a sandstone reservoir which could produce petroleum at 10,000 feet might become much too impermeable to be of any economic value at 20,000 feet. Cementation, which fills part or all of the pore space, also tends to increase with depth. Figure 2-22 shows the effect of compaction for a poorly sorted sandstone from Ventura, California. The silhouettes are based on photomicrograph, but are easier to see in black and white as shown than as a photograph. Note how the pore space decreases from surface conditions to the second, fourth, and so on to the ninth zone and finally to the Miocene sands. There is still quite a bit of porosity in the Miocene, but as can be seen by the very small size of pores, the permeability has decreased greatly.

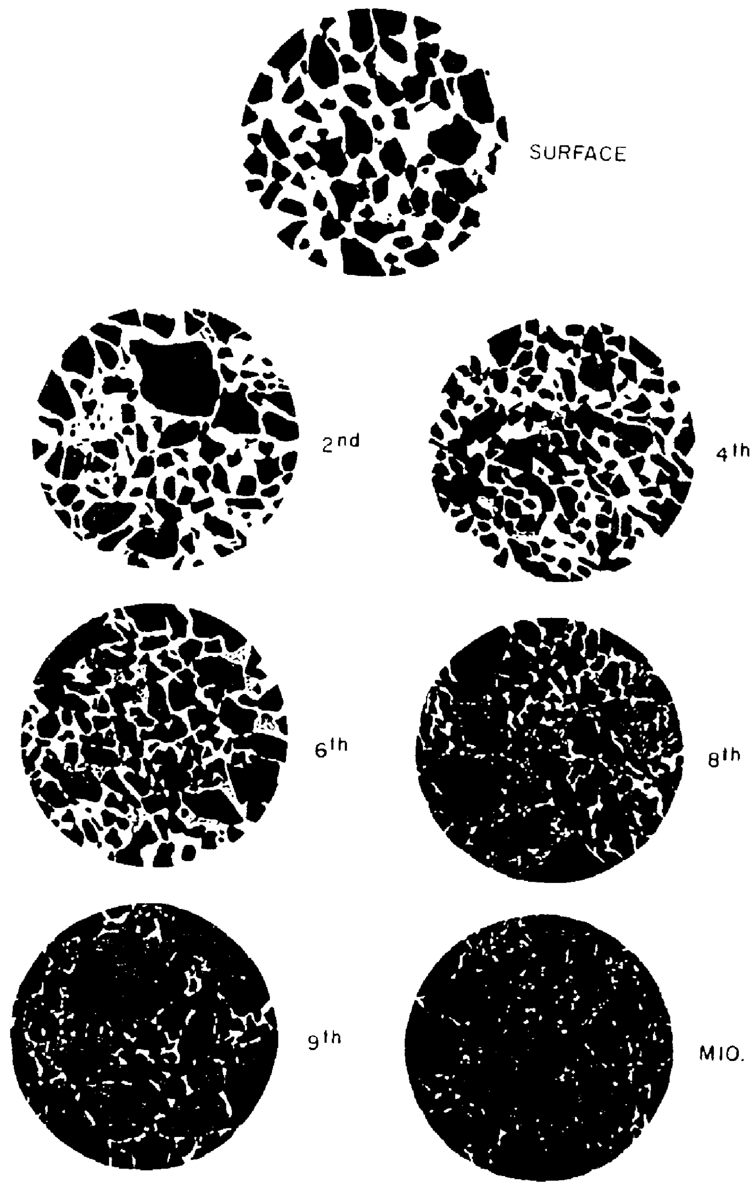

Figure 2-22: General Porosity Decrease with Depth

Carbonates: Carbonates are a complex group -- difficult to study and difficult to interpret. They are very different from sandstones and shales, especially in their susceptibility to post-depositional change, particularly when changed from calcium carbonate to the calcium magnesium carbonate form (dolomite) through the dolomitization process. In carbonates the porosity, permeability, and pore space distribution are related to both the depositional environment of the sediment and the changes that have taken place after deposition. Figure 2-23 is a diagram illustrating the evolution of some dolomite textures and pore types. The original sediments ranging from lime mud to lime sand are depicted and pore size column. Diagenetic (or later) processes will change porosity pore size distribution, as shown to the right and left. Note that lime mud is preferentially dolomitized. The other particles may then be dissolved out, leaving pores or larger holes that may or may not be interconnected. This is shown to the left of the center in the figure. To the right, on the other hand, note the good porosity and permeability in the open network of dolomite crystals. This illustrates two basic types of carbonate porosity:

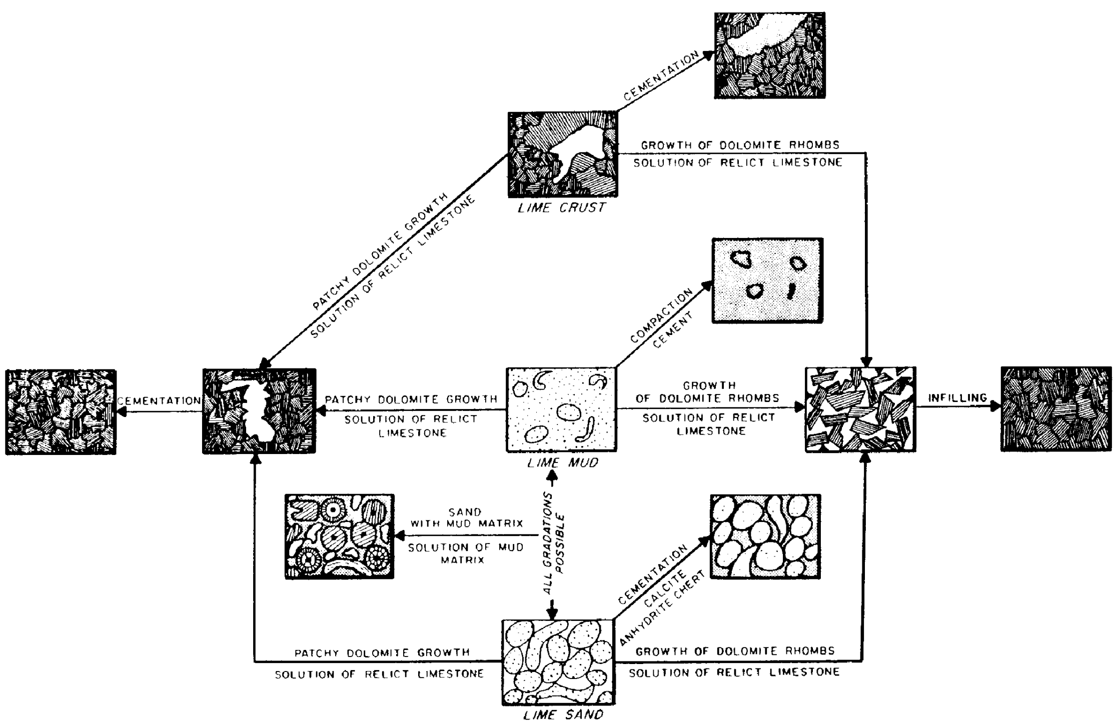

Figure 2-23: Evolution of Some Dolomite Textures and Pore Types

interparticle between grains or crystals, and intraparticle due to particle solution; there may be combinations of the two. Going more to the left, it can be seen that cementation and infilling have taken place, destroying most, if not all, of the porosity. When volume loss occurs due to recrystallization, irregular voids are formed called vugs (vuggy porosity).

Permeability is controlled by the size of the passages between the much larger pores and vugs. Consequently, a highly porous rock may have little or no permeability if these interconnections are very small or absent. On the other hand, some very fine-grained carbonate rocks have an extensive network of interconnected pore space with enough permeability to be able to yield economic volumes of oil. Intercrystalline pores tend to be interconnected, and rocks with high intercrystalline porosity are normally permeable as found in many highly productive dolomite reservoir rocks.

Carbonates can be extensively fractured. In this situation, even without porosity and permeability in the main body of the formation, economic amounts of oil can exist if the source and other conditions of accumulation are present.

Estimations of Porosity and Permeability: Porosity is a measure of the pore space in the body of a reservoir rock, usually expressed as a percent of the unit volume. Permeability is the measure of the ease with which a fluid flows through the connected pore spaces in a reservoir rock. Accurate estimations of porosity and permeability are not possible without the use of core analysis. However, when clean and dry, samples can be generally described in terms of visual porosity by using the highest possible microscope powers. For this to be meaningful, grain distribution size, type and abundance must be included in the description.

Porosity is frequently described as follows (this is a guide only - it is not intended to be absolute):

over 15 percent	good
10 - 15 percent	fair
5 - 10 percent	poor
less than 5 percent	trace

Permeability can be estimated qualitatively without core analysis, by using the cuttings from the gas detector. A blender is present in every logging unit and is used to agitate, break up and mix cuttings. The amount of gas released, which is drawn off and analyzed, is related to permeability and porosity. Cuttings with good permeability contain little gas, for it is assumed to have escaped before reaching the blender stage of examination. A more porous but less permeable formation, however, is more likely to contain gas. The lack of pore space communication produces a trapping effect which is released only when blender-agitated.

It is possible to deduce from this test that if a gaseous formation is penetrated (indicated from Total Gas instrument readings), and blender readings (from the cuttings gas instrument) from the same formation are low, it is likely to be both porous and permeable. A high blender reading would have indicated a low or nonpermeable but certainly porous formation.

In a situation where flushing of the formation has occurred (where the jetting action of the bit and differential pressure has forced formation fluids and gases away from the borehole), very little or no gas will be detected. Cuttings gas also will be low or nonexistent. If the formation is visibly porous from the cuttings and it is possible that the drilling fluid (hydrostatic head) is overbalanced, flushing should be suspected. Oil and gas shows can and have been overlooked because of flushing. It should always be borne in mind that flushing can occur.

Traps

Once the hydrocarbons have been generated and expelled from the source rock, migration is a continuous process -- regardless of whether they are moving through a reservoir rock or through a fracture system. Obviously, a barrier or trap is needed to impede this migration in order to get an accumulation.

A trap is produced by a set of geological conditions which cause oil and gas to be retained in a porous reservoir, or at least allowed to escape at a negligible rate. Shales and evaporites make good seals, although any unfractured rock that has a displacement leakage pressure higher than that of the hydrocarbon accumulation will seal a trap.

Most traps are not filled to their structural or stratigraphic spill point. A spill point is illustrated by the successive diagrams in Figure 2-24. In Stage 1 the stratification of gas, oil and water is above the trap spill point. In Stage 2, hydrocarbons fill the trap to the spill point; oil is spilling out and migrating further up-dip. In Stage 3, the trap is filled with gas. Gas moving from below enters the trap, but a like volume spills out at the same time; oil bypasses the trap entirely. Incomplete filling of a trap is more likely the result of the seal not sustaining the greater hydrocarbon column pressure rather than being the result of insufficient oil and gas to fill the trap (Figure 2-25). For this reason, traps often may be filled to capacity and yet have water levels far above the spill point.

Traps for oil and gas under hydrostatic conditions have two general forms: the trapping factor is either (1) an arched upper surface or (2) an up-dip termination of their reservoir. Figure 2-26 shows some of the simpler forms.

Traps for hydrocarbons under hydrostatic conditions (liquid at rest) are of structural or stratigraphic origin, either alone or in combination, and have horizontal gas-water or oil-water contacts. Hydrodynamic (moving liquid) traps may also occur in different structural environments, but they are characterized by inclined gas-or oil-water contacts.

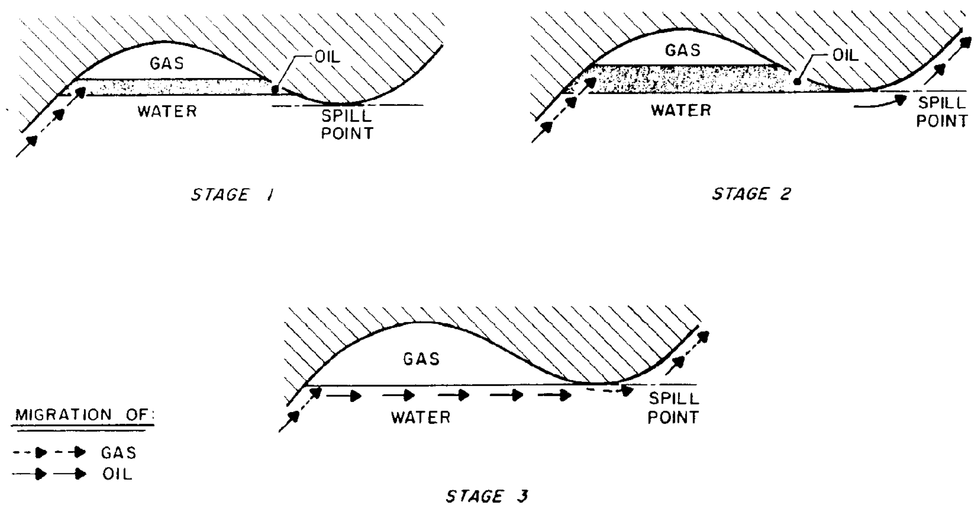

Figure 2-24: Spill Point of a Hydrocarbon Trap

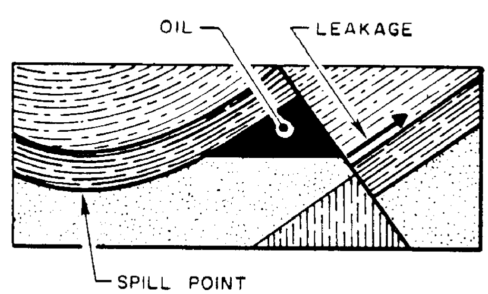

Figure 2-25: Fault Trap Leakage

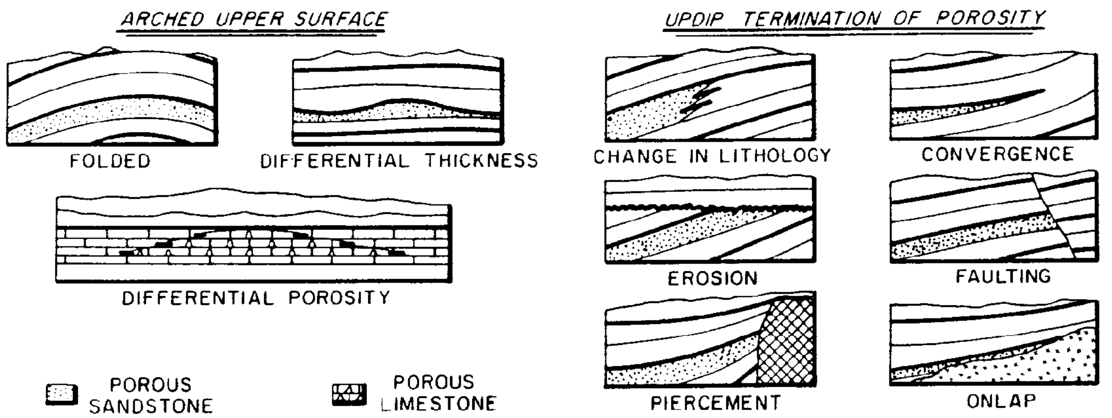

Figure 2-26: Basic Reservoir Traps

Anticlinal Traps: These vary widely in shape and size. However, they all have a common characteristic, a gas-water or oil-water contact completely surrounds an accumulation of hydrocarbons. The structure generally extends through a considerable thickness so that traps are formed in all the potential reservoir rocks. The culminations of the various hydrocarbon accumulations will be offset if the anticline is asymmetric (not uniformly shaped) so that a shallow accumulation may not overlie a deeper one even though it is on the same structure. An example of this can be seen in the anticlinal traps associated with rotational faults (discussed under Fault Traps).

Fault Traps: These traps depend upon the effectiveness of the seal at the fault. The seal may be the result of placing different types of formation side by side (for example, shale against sand), or it may be caused by impermeable material called “gouge” within the fault zone itself. The simple fault trap may occur where structural contours provide closure against a single fault. However, in other structural configurations, such as a monocline, two or even three faults may be required to form a trap. In fault trap accumulations, the oil-water contact closes against the fault or faults, and is not continuous as in the case of anticlinal traps. Fault trap accumulations tend to be elongated and parallel to the fault trend.

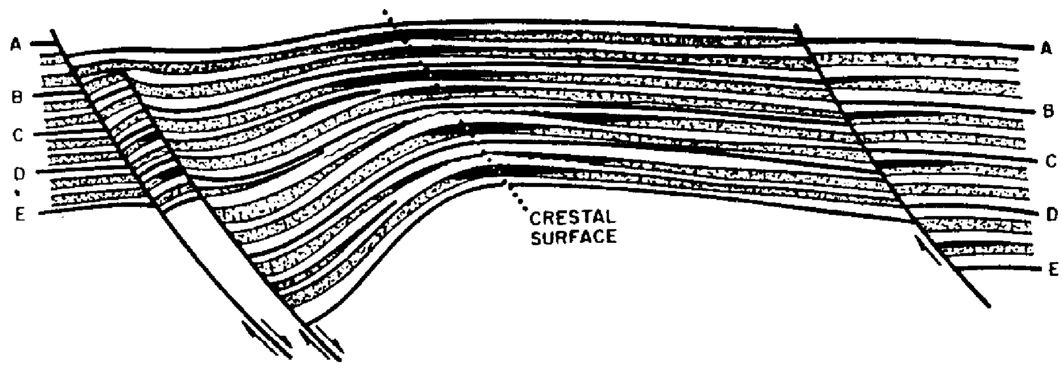

Figure 2-27: Potential Hydrocarbon Traps Associated with Rotational Faults

Many kinds of traps are associated with curved rotational faults; these are especially common in the U.S. Gulf Coast area (Figure 2-27). Accumulations tend to be along the faults and are found in fault traps and anticlinal traps in a complex pattern. An understanding of the nature of these traps is most important for their efficient development.

Traps associated with thrust faults may be either fault traps, as in the lower sands or anticlinal, as in the uppermost sand (as illustrated in Figure 2-28). Accumulations in such traps usually tend to be elongated and parallel to the direction of thrust; they may be quite long but relatively narrow. Thrust traps are often compound.

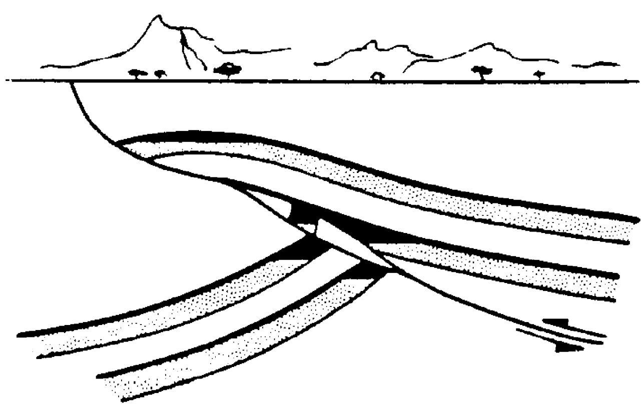

Figure 2-28: Thrust Traps

The intrusion of underlying material (usually salt or shale) into overlying strata often forms a variety of traps, both structural and stratigraphic. Figure 2-29 illustrates three types of traps. Piercement may be more or less circular -- typical of the salt dome oil fields in the U.S. Gulf Coast and Northern Germany -- or long and narrow as in the oil fields of Romania. The salt and associated material forms an efficient up-dip seal. Hydrocarbon accumulations in the peripheral traps around a salt plug may not be continuous. Oil accumulations are usually broken into segments in smaller traps formed by modifying faults or structural closure against the plug. This discontinuous nature of oil accumulations in piercement traps is detrimental to development operations because it cannot be predicted and thus, increases the risk of dry holes.

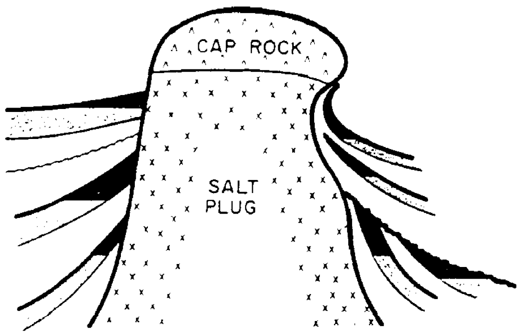

Figure 2-29: Piercement Traps Associated with a Salt Dome

Stratigraphic Traps: These result from lateral change that prevents continued migration of hydrocarbons in a potential reservoir bed. Many are directly related to their environment of deposition, but others - particularly carbonates - are caused by later changes such as dolomitization. Many large oil and gas fields are associated with this type of trap. In the U.S., the East Texas Field accumulation occurs in the truncated edge of the Woodbine Sand below an unconformity sealed by the Austin Chalk as shown in Figure 2-30.

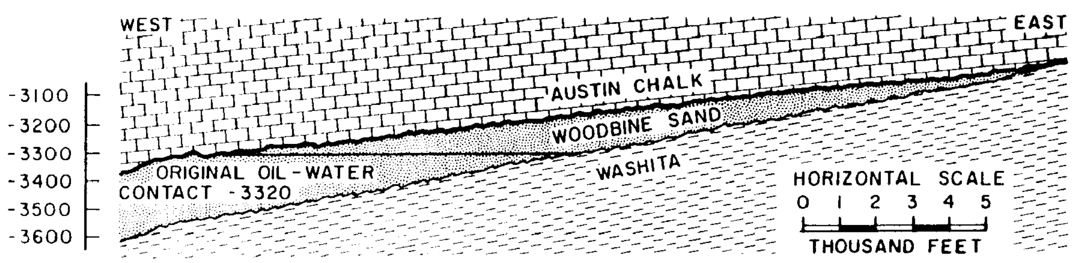

Figure 2-30: Cross-Section of Pinchout Trap between Unconformities, East Texas Field

Lenticular Traps: These pinch out or change permeability on all sides. Lenticular traps are common in carbonates, usually occurring in the upper part of reef carbonate buildups.

Petroleum Reservoirs

A petroleum reservoir is a trap containing commerical quantities of hydrocarbons (gas and oil) and water in varying proportions. These fluids are contained within the pore spaces of formation (among the grains of sandstones or in the cavities of carbonates). The pore spaces are interconnected so that the fluids can move through the reservoir. The porous formations have be cut off on all sides, above and below, in such a way that the only escape for the fluids will be through a wellbore drilled into the reservoir.

Physical Characteristics

In order to have a producing reservoir, the following conditions must exist:

- There must be a body of rock having sufficient porosity to contain the reservoir fluids and permeability to permit their movement.
- The rocks must contain oil or gas in commercial quantities.
- There must be some natural driving force within the reservoir, usually gas or water.

Special attention should be given to the natural driving force. Oil, in itself, does not have such force or energy -- it cannot move itself. Only the energy stored in the reservoir in the form of gas or water under pressure can move the oil from the well. When this energy has been spent, only the slow method of gravity drainage remains to get the oil to the wellbore. However gravity does not always work to move oil in the right direction to reach a well.

The porosity of a formation is its capacity for reservoir fluids. Porosity may vary from less than 5 percent in a tightly cemented sandstone to more than 30 percent for unconsolidated sands. Accurate determination of formation porosity is an extremely difficult matter. While it is true that laboratory technicians who specialize in this work can make fairly accurate determination on cores taken from a pay section, most reservoirs vary over such wide ranges that it is difficult to arrive at any figure that may be correctly called “average” for a given reservoir (especially in carbonates).

Figure 2-31 shows representative porosity and permeability determinations from some oil fields. The relationship between the porosity and permeability of a given formation is not necessarily a close or direct one. However, high porosity is often accompanied by high permeability. The extreme variations that may be found in a given reservoir are shown in the two permeability determinations from the U.S. East Texas Field.

Sand	State	Field	Porosity %	Permeability (md)
Woodbine	Texas	East Texas	22.1	3390.0
Woodbine	Texas	East Texas	19.7	192.0
Wilcox	Oklahoma	Oklahoma City	16.9	677.0
Gloyd (Lime)	Texas	Rodessa	20.0	130.0
San Andres Lime	Texas	Goldsmith	12.0	50.0

Figure 2-31: Representative Permeability and Porosity Determinations

Reservoir Pressure

The fluids in the pores of a reservoir rock are under a certain degree of pressure, generally called reservoir pressure or formation pressure. A normal reservoir pressure at the oil-water contact approximates very closely the hydrostatic pressure of column of saltwater to the depth. The hydrostatic pressure gradient varies somewhat, depending upon the amount of dissolved salts in the average water for a given area. For fresh water it is 0.433 psi/ft of depth. For water containing 80,000 ppm of dissolved salts (U.S. Gulf Coast) the pressure gradient is approximately 0.465 psi/ft. However, normal marine water is about 35,000 ppm dissolved salts, approximately 0.446 psi/ft. Reservoirs can obtain fluids under abnormal pressure up to as high as 1.00 psi/ft of depth.

Abnormal pressure may develop in isolated reservoirs as a result of compaction of the surrounding shales by the weight of the overburden. During this process, water is expelled from the shale into any zone of lower pressure. This may be into a wholly confined sandstone which does not compact as much as the shale; consequently, its contained water is under a lower pressure than that in the shale. Ultimately, a state of equilibrium can be reached when no further water can be expelled into the sandstone, and its fluid pressure will then approximate that of the shale.

Since compaction of sandstones is related to the pressure of the pore fluid as well as to the pressure exerted by the overburden, it follows that abnormally pressured sandstones are partially supported by the fluid pressure and partially by grain-to-grain contact. Consequently, when the abnormal pressure is reduced by production, compaction of the reservoir begins to occur. Subsurface compaction can cause serious problems, not only because of collapse of casing in wells, but also because it is reflected at the surface by subsidence. Such occurrences result in very expensive landfill and well repair costs. It has also been demonstrated that there can be a direct relationship between subsidence and the amount of liquid withdrawn. Studies of the Wilmington Field (California) indicated that repressuring by water injection would increase oil recovery and stop compaction. Subsidence was stopped by such a program, and in places the surface regained some of the elevation that was lost. However, careful work on sediments has shown that this compaction is not entirely reversible. Some permanent reduction of porosity and permeability results from permitting abnormal reservoir pressure to decline, and this may adversely affect the rate of production and possibly the ultimate recovery.

Oil Field Fluids

The distribution of fluids will be different for each reservoir, depending on:

- Source Rock
- Reservoir Rock
- Porosity
- Permeability
- Relative Permeability of Reservoir Fluids
- Relative Densities of the Fluids
- Hydrodynamics of the Reservoir
- Migration Variables (lithology, temperature, etc.)

By definition, a fluid is any substance that will flow. Oil, water and gas are all fluids by this definition. Though oil and water are liquids, gas is not.

Reservoir Water

Many oil reservoirs are composed of sediments which were deposited on the floor of seas and oceans, causing these sedimentary beds to be originally saturated with saltwater. Part of this water was displaced in the process of the formation of oil accumulations. That which remained in the formation has been given the name of connate interstitial water -- “connate” from the Latin meaning “born with” and “interstitial” because the water is found in the interstices, or pores, of the formation. By common usage, this term has been shortened to “connate water” and always means the water in the formation when development of the reservoir was started. Connate water determinations (Sw) using core samples are expressed as a percentage of the volume occurring in the pore spaces of the reservoir. Swiar (irreducible connate water saturation) is the fraction of pore space which may be retained as nonmovable wetting phase even though oil and gas may be flowing in the same pore spaces under the influence of relatively large pressure gradients. In addition to the connate water distributed throughout the reservoir section with the oil and gas, nearly all petroleum reservoirs have water-bearing formations down-dip from the payzones. All the pore spaces of such formations are filled with water. It is the volume of “free” water which supplies the energy for the “water drive” in some reservoirs. With this “water drive mechanism”, as some hydrocarbons are liberated via the wellbore the water rushes into the vacated pore spaces, increasing in volume and pushing more hydrocarbons to the surface.

The character of reservoir water is determined by

- Water Saturation
- Concentration of Dissolved Solids
- Composition of Dissolved Solids

Water saturation (Sw) is determined directly by core analysis or indirectly from wireline logging tools. Concentrations of dissolved solids are analyzed directly by use of a hydrometer and indirectly with a resistivity tool to measure the resistivity of water (Rw). Resistivity of water in the interstitial pore space is a measure of all ions and therefore, an indirect measure of dissolved solids. Fluid density increases with increased dissolved solids (Figure 2- 32).

Fresh	Seawater	Heavy Brine
200-300 ppm 8.33 lb/gal	35,000 ppm 8.6 lb/gal	300,000 ppm 10.0 lb/gal

Figure 2-32: Dissolved Solids (Concentrations)

Dissolved solid composition can only be analyzed using water directly from the well. As all brines have similar ionic analyses, even though the total concentrations may differ greatly, it suggests that they are all diluted forms of the same original water (i.e. sea water). In the oil field-water analyses in Figure 2-33 it can be seen that, except for the Miocene example, the NaCl ppm readings are very high; in fact, much greater than that of seawater. This is an important fact to be considered when testing a well, for analysis of recovered water may possibly indicate whether it is formation water or water used in the testing procedure.

The oil-water contact is always transitional and may be from two feet to several hundred feet thick. There are three possible definitions and locations:

- Depth above which only irreducible water saturation (Sw) is present
- Depth below which Sw = 100 percent
- Depth below which oil will not be produced

Pool	Reservoir Rock Age	Parts Per Million (ppm)							Total ppm
		C1-	SO_4-	CO_3	HCO_3	$Na^+ + K^+$	Ca^{++}	Mg^{++}	
Seawater Seawater, percent	- - -	19,350.0 55.3	2,690.0 7.7	150.0 0.2	- - -	1,000.0 31.7	420.0 1.2	1,300.0 3.8	35,000
Lagunillas (Western Venezuela)	Miocene 2000-3000 ft	89	- - -	120	5,263	2,003	10	63	7,548
Conroe (Texas)	Conroe sands (Eocene)	47,100	42	288	- - -	27,620	1,865	553	77,468
East Texas	Woodbine sand (U. Cretaceous)	95,275	198	387	- - -	24,653	1,432	335	68,961
Burgan (Kuwait)	Sandstone (Cretaceous)	95,275	198	- - -	360	46,191	10,15 8	2,206	154,388
Rodessa (Texas-La.)	Oolitic lime- stone (L. Cretaceous)	140,063	284	- - -	73	61,538	20,91 7	2,874	225,749
Davenport (Oklahoma)	Prue sand (Pennsylvanian)	119,855	132	- - -	122	62,724	9,977	1,926	194,736
Bradford (Pennsylvania)	Bradford sand (Devonian)	77,340	730	- - -	- - -	32,600	13,26 0	1,940	125,870

Figure 2-33: Oil Field Water Analysis

Reservoir Oil and Gas

The relationship between oil and gas in the reservoir depends upon the degree to which the oil is saturated with gas -- i.e., the amount of “dissolved gas” contained in the liquid oil. Natural gas is always associated with oil (however oil is not always associated with gas), and the energy supplied by gas under formation hydrostatic pressure is probably the most valuable drive in the withdrawal of oil from reservoirs.

Gas is associated with oil and water in reservoirs in two principle ways -- as “solution gas” and “free gas”. Given suitable conditions of pressure and temperature, natural gas will “stay in solution” in oil in a reservoir. High pressure and low temperature are favorable conditions for keeping gas in solution. When the oil is brought to the surface and the pressure relieved (as in separator), the gas comes out of solution.

The volume of gas that remains in solution depends on the reservoir pressure and temperature. When there is less gas in the reservoir than the volume of oil is capable of absorbing, the oil is said to be undersaturated. The East Texas Field with a reservoir pressure of about 1100 psi produces oil with about 325 ft^3 of solution gas per barrel. The reservoir temperature is 143^oF. At that temperature and pressure it would require about 400 ft^3 of gas per barrel of oil to have saturated conditions. Thus, the East Texas Field produces undersaturated oil. On the other hand, crude oil in the West Pampa Pool of the Texas Panhandle is supersaturated. Oil from this pool carries about 175 ft^3 of gas per barrel in solution and produces another 725 ft^3 of free gas.

Free gas tends to accumulate in the highest structural part of a reservoir to form a gas cap. As long as there is free gas in a reservoir gas cap, the oil in the reservoir will remain saturated with gas in solution. Having gas in solution lowers the viscosity of the oil, making it easier to move to the wellbore.

Composition of Petroleum

Petroleum is composed of carbon and hydrogen with minor amounts of sulfur, nitrogen and oxygen (Figure 2-34). Increases in the minor elements lowers the value of crude.

Components	Oil	Asphalt	Kerogen
Carbon	84.0	83	79
Hydrogen	13.0	10	6
Sulfur	2.0	4	5
Nitrogen	0.5	1	2
Oxygen	0.5	2	8
	100.0	100	100

Figure 2-34: Chemical Composition of Oil, Asphalt and Kerogen

Hydrocarbons make up over 90 percent of most crude oils, and those hydrocarbons in crude oils vary in molecular size and molecular type (Figure 2-35).

Hydrocarbon Size Distribution: Dry gas consists predominantly of methane. Wet gas contains methane, ethane, propane, butanes and minor amounts of heavier hydrocarbons. Distillation separates crude oil into molecular groups of different sizes, such as gasoline, kerosene, gas-oil, lubricating oil and residuum. High API gravity crudes have a high gasoline and low residuum content, whereas low gravity oils are low in gasoline and high in residuum. API gravities are used for classifying oils by reference to their densities, as defined by the American Petroleum Institute. Numerically, the value is obtained from the formula:

$$\frac{141.5}{\text{S.G. at } 16°C(60°F)} - 131.5$$

(S.G. = Specific Gravity)

The API gravity can range from -1 to +101. The larger the number, the lighter the oil; thus a light crude may be 40^{o}API, a medium one 28^{o}API and a heavy crude 20^{o}API.

Molecular Size	**Weight%**
Gasoline (C4 - C10)	31
Kerosene (C11 - C12)	10
Gas Oil (C13 - C20)	15
Lubricating Oil (C20 - C40)	20
Residuum (>C40)	24
	100
Molecular Type	
Paraffins	30
Naphthenes	49
Aromatics	15
Asphaltics	6
	100

Figure 2-35: Composition of a Typical Crude Oil

Hydrocarbon Type Distribution: Most crude oils contain some of the following different types of structures, which are illustrated in Figure 2-36 (A,B,C and D).

- Saturated hydrocarbons (those containing only single bonds between carbon atoms). Normal paraffins are straight chains of carbon atoms. Isoparaffins are branched chains of carbon atoms. Naphthenes (cycloparaffins) are rings of carbon atoms.
- Unsaturated hydrocarbons (those containing double bonds between carbon atoms). Olefins are compounds having one bond between carbon atoms. Aromatics are compounds containing one or more benzene rings. Benzene has a symmetrical ring of six equivalent carbon and hydrogen atoms in a plane.

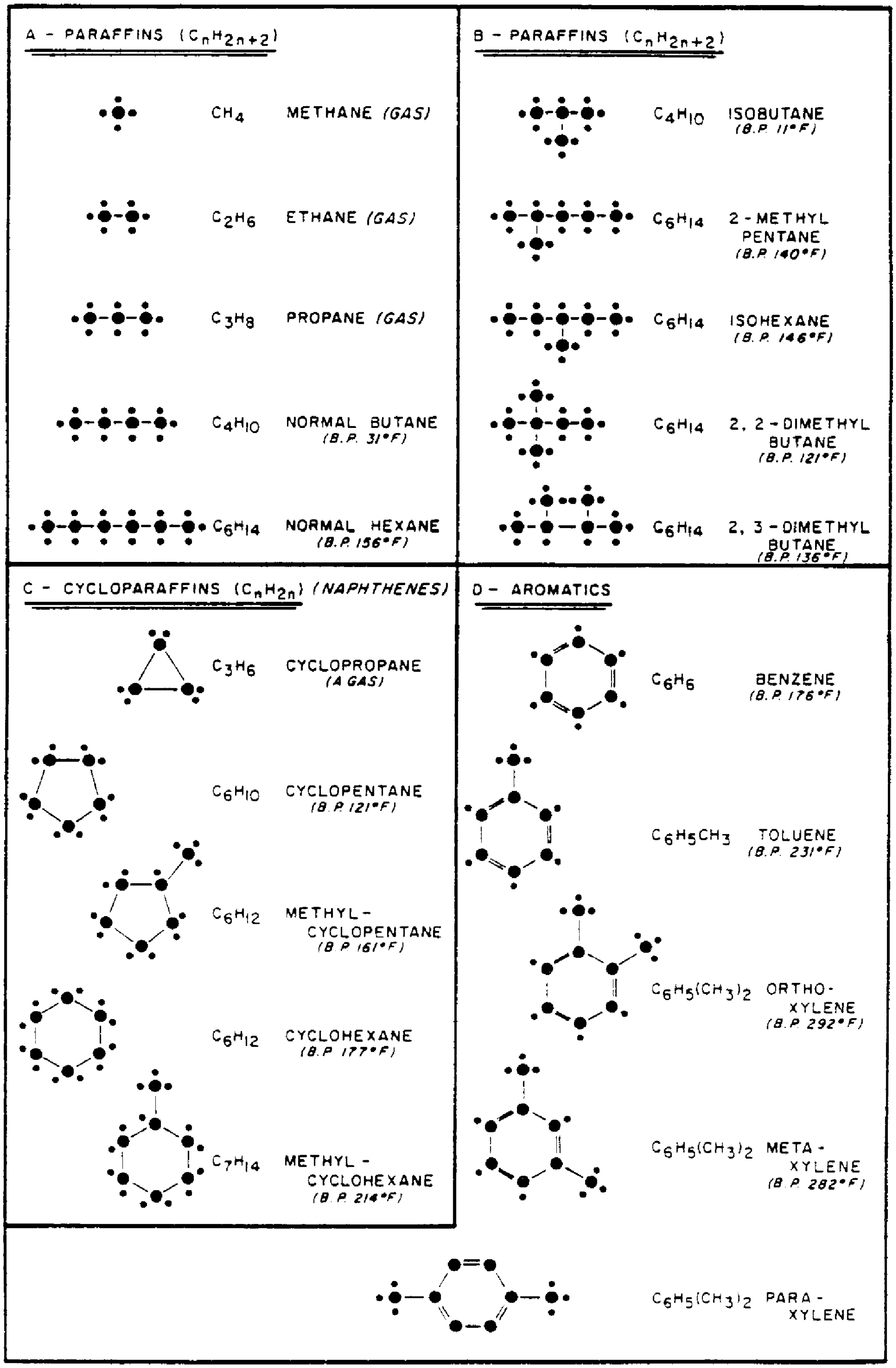

Figure 2-36: Typical Hydrocarbon Structures

Typical paraffins are methane, ethane, propane, butane, pentane, hexane, heptane, octane, nonane, decane. Naphthenes, or cycloparaffins, include cyclopropane, cyclopentane, cyclohexane. Olefins include ethylene, propylene, butylene. Aromatics include benzene, toluene, xylene, naphthalene, and anthracene.

Wellsite chromatographs are capable of detecting C1to C5. If further analysis is necessary, this will usually be done during testing when gas samples are taken downhole using a test tool. Figure 2-37 illustrates hydrocarbons that are commonly detected at the wellsites.

Name	Chemical Formula	Physical State at 60×^{o}F and 1465 psi	Molecular Weight	Boiling Point (^{o}C) at Normal Conditions
Nethane	CH_4	Gas	16.04	-161.4
Ethane	C_2H_6	Gas	30.07	-89.0
Propane	C_3H_8	Gas	44.09	-42.1
n-Butane	C_4H_{10}	Gas	58.12	0.55
iso-Butane	C_4H_{10}	Gas	58.12	-11.72
n-Pentane	C_5H_{12}	Liquid	72.15	36.0

Figure 2-37: Hydrocarbons Commonly Detected at the Wellsite

Source of Petroleum

Petroleum originates from a small fraction of the organic matter deposited in sedimentary basins. Most of the organic matter is the remains of plants and animals that lived in the sea, and the rest is land-delivered organic matter carried in by rivers and continental runoff, or by winds.

Living organisms are composed of carbohydrates, proteins, and lipids (fats) and lignin in varying amounts. These compounds are degraded by micro-organisms into the monomer sugars, fatty acids, etc. These immediately condense into nitrogenous and humus complexes -- progenitors of kerogen.

Some hydrocarbons are deposited in the sediments, but most form from thermal alteration at depth. Lipids are closest to petroleum in composition among the major life substances (Figure 2-38). Lipids (fats and hydrocarbons) are most concentrated in the lowest forms of life (Figure 2-39).

Substance	Elemental Composition in Weight (%)				
	C	H	O	S	N
Carbohydrates	44	6	50.0	- - -	- - -
Lignin	63	5	31.0	0.1	0.3
Proteins	53	7	22.0	2.0	16.0
Lipids	80	10	10.0	- - -	- - -
Petroleum	82-87	12-15	0.1-2.0	0.1-5.0	0.2

Figure 2-38: Average Chemical Composition of Natural Substances

Life Form	Weight Percent of Major Constituents			
Plants	Proteins	Carbo-hydrates	Lignin	Lipids
Spruce Wood	1	66	29	4
Oak Leaves	5	44	32	4
Scots Pine Needles	7	41	15	24
Phytoplankton	15	66	--	11
Diatoms	29	63	--	8
Lycopodium Spores	8	42	--	50
Animals				
Zooplankton	53	5	--	15
Copepads	65	22	--	8
Higher Intertebrates	70	20	--	10

Figure 2-39: Composition of Living Matter

Petroleum contains traces of several substances that could have come only from living organisms. Examples are:

- Porphyrins related to hemin and chlorophyll
- Optically active compounds (they will rotate the plane of a ray of polarized light)
- Structures related to cholesterol, carotene and terpenes
- A predominance of odd-numbered paraffin chains

Carbon isotope data suggest that the lipids of plants are an important source of petroleum.

Normal (straight chain) paraffins in crude oil sometimes show a predominance of odd-numbered chain lengths. This odd-numbered chain length has a biochemical origin and tends to predominate in the high molecular weight in oils, derived from continental or near-shore organic matter, and in the low ranges for marine organic matter.

Coals, kerogen, asphalts, and petroleum all originate from organic matter deposited with sediments. Differences are due to different source materials, dispersal and environments of deposition and diagenesis (Figure 2-40). The biological origin of these fossil fuels is proven by their chemical composition and physical structure containing remnants of living organisms.

Coals		**Dispersed Organic Matter**	**Bitumens**
Massive land plants	algae, plankton, spores, resins	Land and marine organic matter deposited with inorganic sediments	Selective fraction(>1%) of organic matter
Concentrated as aromatic HMW humus	Concentrated as jelly like slime-sapropel	Absorbed on mineral matter as aliphatic LMW humus	Dispersed lipids carried by migrating waters to reservoirs
Peat Lignite Bituminous Coal Anthracite	Canels and Torbanites	Kerogen	Petroleum Waxes Asphalts Asphaltites Pyrobitumens

Figure 2-40: Origin of Organic Matter Deposited with Sediments

Origin of Gases

The following are the generally accepted theories for the origin of gases. Methane is formed by bacterial decay of organic material; it is a major product of the diagenesis of coal and is given off from all forms of organic matter during diagenesis. It is the most common hydrocarbon in subsurface waters and is an end product of petroleum metamorphism. When heated, kerogen in shales from gas-producing areas gives off much greater quantities of methane as compared to the kerogen of shales from oil-producing areas.

Hydrogen sulfide originates from the reduction of sulfates in the sediments and from sulfur compounds in petroleum and kerogen. Carbon dioxide is derived from the decarboxylation of organic matter, and from HCO_3 and $CaCO_3$. Nitrogen is derived from the nitrogen in organic matter and from trapped air. Helium is derived from the radioactive decay of uranium and thorium. During the oil genesis and coalification process, the order of generation is generally nitrogen, CO_2 and methane.

Occurrence of Petroleum

Only about 2 percent of the organic matter dispersed in fine-grained rocks becomes petroleum, and only about 0.5 percent of it ends up in a commercial reservoir accumulation. This emphasizes the inefficiency of the origin, migration and accumulation processes of hydrocarbons.

The ratio of dispersed hydrocarbons to reservoired hydrocarbons is about 200 to 1 on a worldwide basis, partly because the volume of potential reservoir rock is small compared to total sediments in the earth's crust. Within prospective parts of oil-forming basins, the ratio generally varies between 10 to 100. Petroleum is found from the Precambrian to the Pleistocene (Figure 2-41), but is increasingly abundant in the younger sediments for several reasons:

- Older oil fields are increasingly destroyed over geologic time
- An increase in continental margins and restricted basins occurred when the continents split during the Jurassic.

Maturation of Petroleum

In most sedimentary basins, the oil in reservoirs becomes lighter (higher API gravity) with increasing depth. Depth has two important effects in altering a crude oil:

- Pressure, which increases with depth, causes diagenesis with resultant clay alteration. Salinity variations affect migration which in turn affects “natural filtration”. Pressure also inhibits chemical equilibrium where a volume change is concerned.
- Temperature, which increases with depth, causes several changes in oil:

  1. Solids with low melting points, or viscous liquids become mobile liquids.
  2. Light hydrocarbons become increasingly soluble in subsurface fluids
  3. Mild cracking of large oil molecules causes small molecules to form.
  4. Large molecules, in turn, polymerized to very large organic structures.

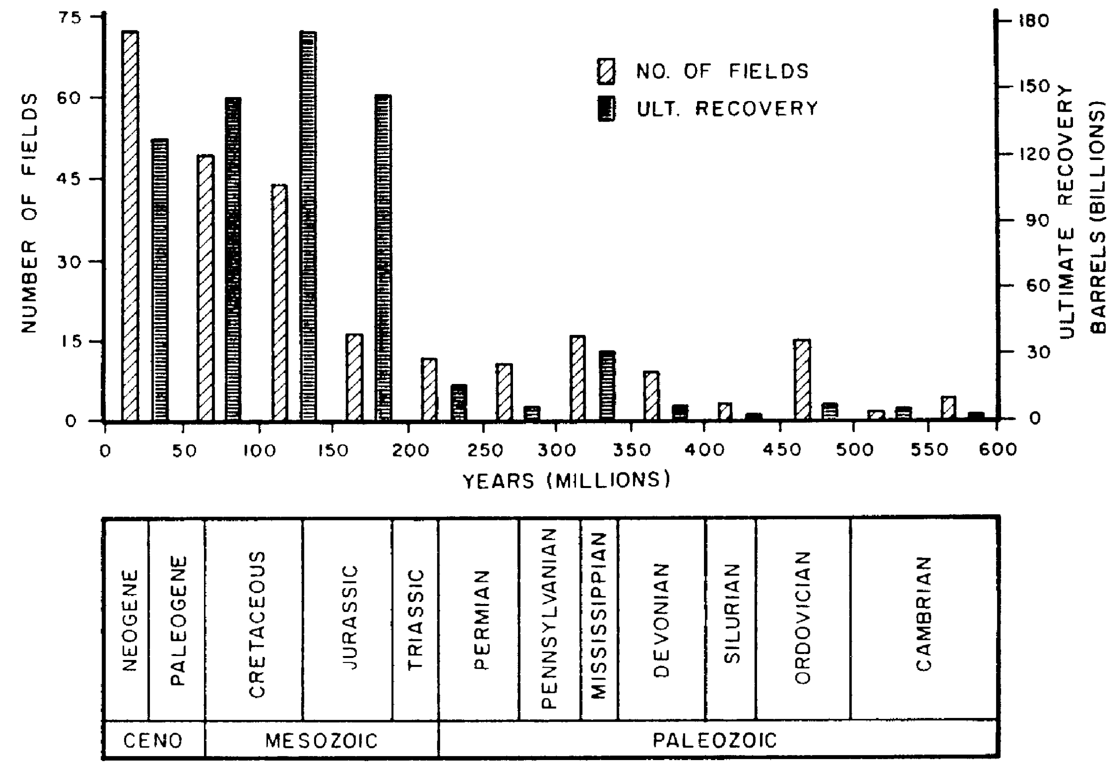

Figure 2-41: Reservoir Age

At 100^{o}C (212^{o}F) all hydrocarbons except methane, ethane and propane are unstable with respect to carbon and hydrogen. At 200^{o}C (392^{o}F) all hydrocarbons except methane are unstable. Methane, therefore will be the only hydrocarbon found in deep, hot sediments.

The degradation of crude oil may occur in several ways. The two most common are through (1) seepage and (2) contact with circulating meteoric water. Seepage may take place along unconformities, through fractures or through continuous sand beds exposed at the surface. Seepage results in the loss of the light hydrocarbons to the atmosphere and the formation of a natural asphalt at the seepage outlet. Sometimes the formation of an asphalt may seal off a seep, other times a transgressive sedimentation cycle may seal it. This results in the preservation of an oil that is heavy compared with comparable oils from the same formation which have not seeped during their geologic history.

Circulating meteoric waters may degrade an oil by carrying off the lighter hydrocarbons, and by oxidizing portions of the crude through contact with oxidizing substances (such as the sulfate ion). In many areas it is very common to find the heavy degraded oils associated with fresh or brackish water and the light original oils associated with saltwater. Micro-organisms also assist in the degradation.

Factors Which Affect The Crude Oil Gravity

The following factors are interrelated in complex manners. Taking each separately is a rough generalization. Formation temperatures and pressures are very influential. If temperatures and pressures are high, hydrocarbon gravity is usually high.

- Geological Age (maturity). Older rocks tend to have higher gravities, but many Tertiary rocks have API of 40+ (e.g. the North Sea). Many Paleozoic rocks have API gravities of +20.
- Depth of Burial. Deeper the reservoir, higher the gravity. The deepest well tend to produce gas.
- Basinal Position. Gradients range from high at the center to low at the edges.
- Tectonism. High gravities are more common in regions of high stress.
- Salinity. Marine sources tends to have higher gravities than fresh/ brackish sources.
- Sulfur Content. Content is high in low-gravity crudes. Main variations are regional, e.g., Middle East crudes are high in sulfurs, Nigerian and Libyan crudes are low.
- Lithology. No apparent relationship.

Properties of liquid petroleums reflecting variations in composition and gravity are illustrated in Figure 2-42.

Impurities Associated with Hydrocarbons

Impurities occur as free molecules or as atoms attached to the larger hydrocarbon molecules -- the so-called nonhydrocarbon compounds. When free, they can be detected with special equipment (Figure 2-43).

Products from Crude Oil

The products from crude oil, their gas ranges and their API gravities are illustrated Figure 2-44.

Properties	High API Gravity	Low API Gravity	Remarks
Viscosity	low	high	Temperature sensitive. Inverse measure of ability to flow. Not pressure-sensitive.
Color	light	dark	Yellow, red brown to black by transmitted light (usually green by reflected light).
Fluorescence	yellows	browns	White-yellow through yellow and brown. Described as color, intensity and hue.
Refractive Index	1.39	1.55	Determined with Abe refractometer
Flash and burn points	low	high	>50°F
Cloud and pour points	low	high	-70°F to +110°F
Coefficient of Expansion	high	low	Noncompressible as far as logging is concerned.
Density	Dependent on compostion. $\text{API gravity} = \frac{141.5}{SG(60°F)} - 131.5$ Normal Range = 16 to 50° API gravity. SG water = 1 = 10° API at 60°F		
Odor	Paraffin and naphthene crudes smell like creosote. Aromatics - unpleasant. Sulfur compounds very unpleasant.		
Optical activity	Rainbow effect. Due to cholesterol (an alcohol $C_{26}H_{45}OH$). Mainly in intermediate disillation range (boiling point 200°F to 300°F)		
Wax content	Related to pour points and viscosity range 0.5% to 45%; manly 7% and consists mainly of normal paraffins. No low wax paraffin crudes have been found but there are some high wax, naphthene crudes (NB ceresin). Wax content apparently high in oil from fresh water/brackish source.		

Figure 2-42: Properties of Liquid Hydrocarbons

Impurity	Equipment Available to Measure Impurity
Sulfur Nitrogen CO_2 Helium Oxygen	H_2S Detector All Gas/Nitrogen Detector TC Chromatograph TC Chromatograph All Gas Detector
Water Salt	Salinity Check ($AgNO_3$ Titration)
Ash	----------

Figure 2-43: Impurities Associated with Hydrocarbons

Crude	Product	Gas Range	Distillate Type	API Gravity
Gas ↑	Natural Gas LNG (Liquid Natural Gas)	C_1, C_2 C_3, nC_4	----------	>110°
	Natural Gasoline Gasoline	IC_4, C_5, C_6, C_7 $C5_+$	Condensate: Light Distillates BP* >160°C	74° to 110° 50° to 95°
	Kerosine Diesel	----------	Middle Distillates: BP 160° to 350°C	30° to 50°
	Fuel Oil Lube Oil	----------	Heavy Distillates: BP 350° to 520°C	18° to 30°
↓ Oil	Wax/Asphalts	----------	Residuum: BP >520°C	----------
	*BP: Boiling Point			

Figure 2-44: Crude Oil Products

Fluid Distribution

Practically all reservoirs have water in the lowest portions of the formation, with the oil just above it (Figure 2-45). The oil-water contact is the prime interest for those concerned with the early development of the field. There is a sharp line dividing the oil and water or the contact line is horizontal throughout a reservoir. There will always be a certain amount of water, even at the top of the oil or gas level.

What is true of the oil-water contact is true to a lesser degree of the gas-oil contact. There are great differences in the specific gravities of oil and gas, oil being much heavier than gas, does not tend to rise very high into the gas zone.

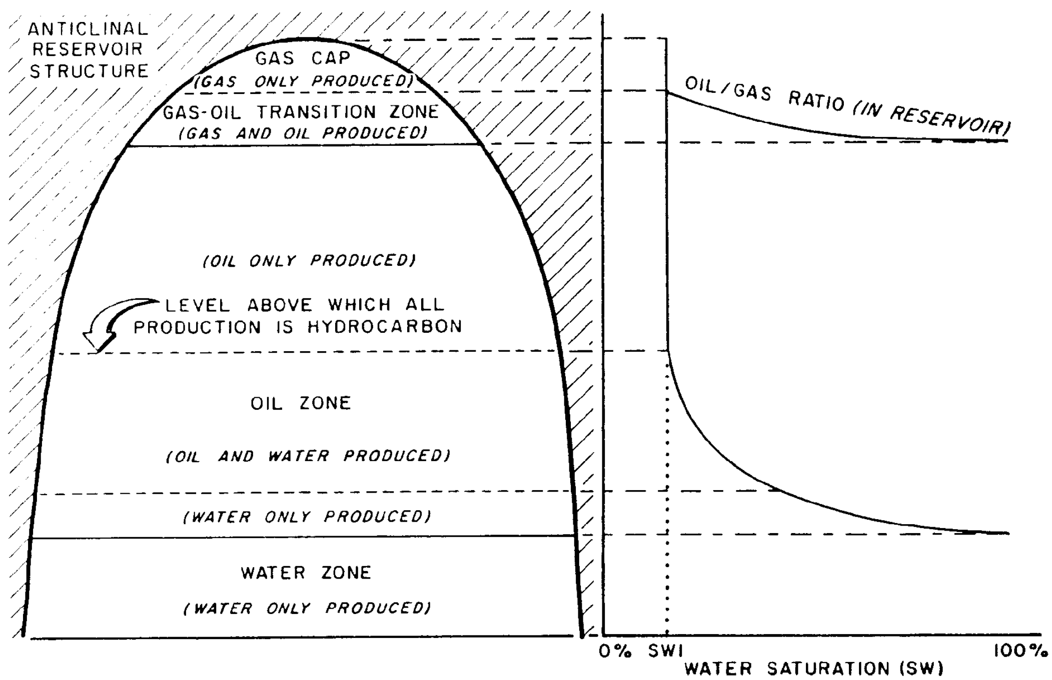

Figure 2-45: Reservoir Fluid Distribution

•Notes•

Rig Types & Their Components

The complexity of the drilling operation determines the level of sophistication of the various rig components. However, even with the considerable variety of rig types, the basic components described, with only a few exceptions are similar and common to each.

Rigs are generally divided into two categories:

- Onshore
- Offshore

Onshore (land) rigs are similar, but offshore rigs are of five basic types - each of which is designed to suit a specific offshore environment. Figure 3-1 illustrates the various types of rigs.

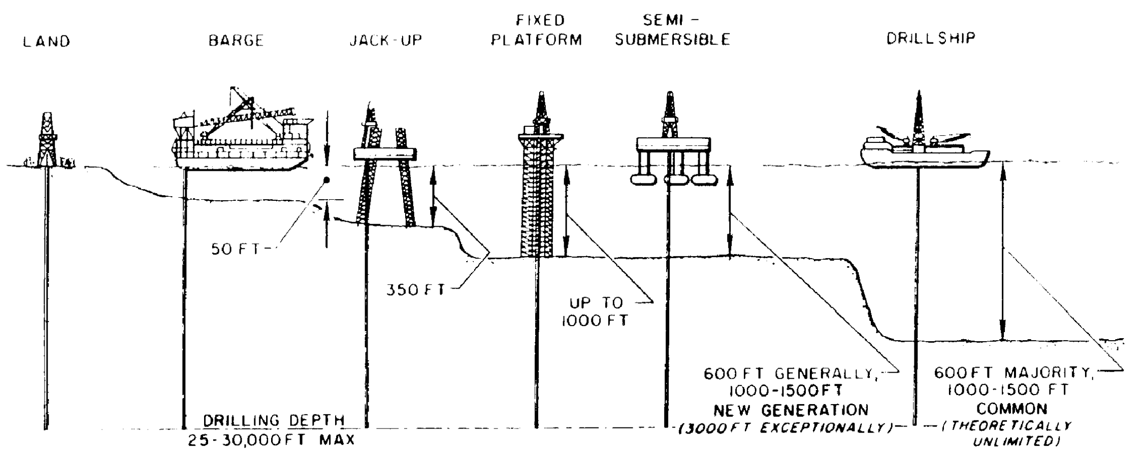

Figure 3-1: Rig Types and Offshore Operating Profiles

Land Rigs

Before rig equipment is brought in, the land must be cleared and graded. Access roads, where possible, must be prepared. For jungle locations, preparing the drill site is more difficult, for access roads do not usually exist and cannot be made. The choice of a drilling location is therefore often dependent on its proximity to a navigable river which can be used to transport the rig equipment and supplies for the duration of the well. If there are swampy conditions, or if the distances are too great to warrant the construction of a road, helicopters can airlift everything to the drill site from a base location.

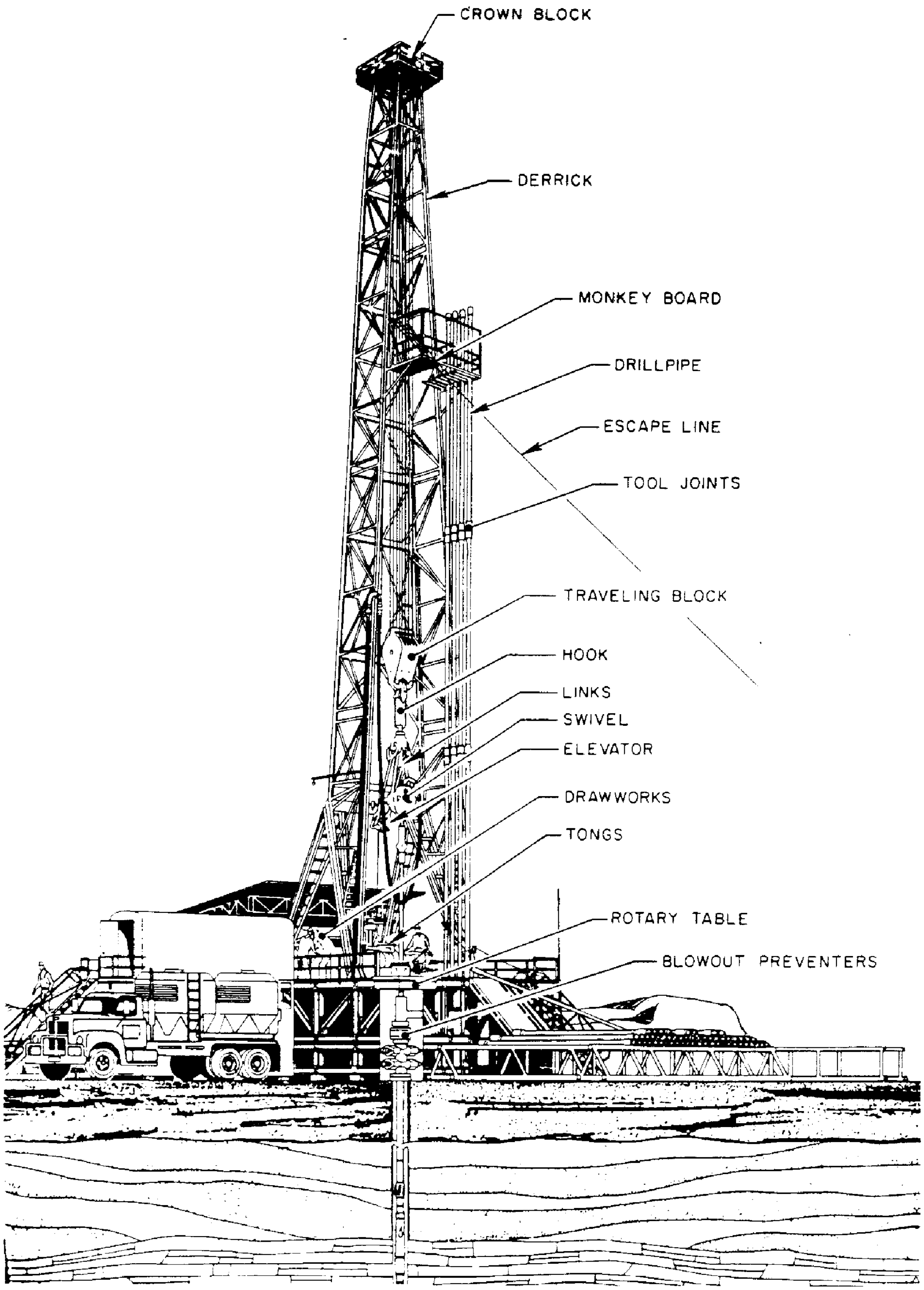

Figure 3-2: Land Rig

On the North Slope of Alaska and other similar areas, site preparation includes an insulating layer to separate the permafrost from the heat of the rig. Pilings are set and frozen in place to support the weight of the drilling rig. A thick layer of gravel is added before the substructure is begun. Polyurethane foam may be used to supplement gravel insulation.

The most common arrangement for a land drilling rig is the cantilever mast (often called a jack-knife derrick) which is assembled on the ground, then raised to the vertical position using power from the drawworks (hoisting system). These structures are made up of prefabricated sections which are fastened together by large pins. First, the engine and derrick substructures are placed in proper position and pinned together by the drilling crew, then the drawworks and engines are made operational. The derrick sections are then laid out horizontally, pinned together, and the mast is raised as a unit by the drill line, traveling block and drawworks. A working land rig is illustrated in Figure 3-2.

Offshore Rigs

Barge

The barge is a shallow draft, flat-bottom vessel equipped as an offshore drilling unit, used primarily in swampy areas. This type of vessel can be found operating in the swamps of river deltas in West Africa, in coastal areas, and in shallow lakes such as Lake Maracaibo, Venezuela. It can be towed to the location and then ballasted to rest on the bottom.

Jack-Up

This mobile drilling rig is designed to operate in shallow water, generally less than 500 ft deep. Jack-up rigs, illustrated in Figure 3-3, are very stable drilling platforms because they rest on the seabed and are not subjected to the heaving motion of the sea. They have a barge-like hull which may be ship-shaped, triangular, rectangular, or irregularly shaped, supported on a number of lattice or tubular legs. When the rig is under tow to a drilling location the legs are raised, projecting only a few feet below the deck, and the structure behaves like a cumbersome floating box; hence it can be towed only in good seas and at slow speed. Upon reaching its location the legs are lowered by electric or hydraulic jacks until they rest on the sea bed and the deck is level, some 60 feet or more above the waves. Most jack-ups have three legs, some have four or five. The legs are either vertical or slightly tilted for better stability. In one design, they are fixed to a large steel mat, which gives it the name of “mat-supported jack-up”. A drilling slot is usually indented into one side of the deck, on some rigs the derrick is cantilevered over one side of the rig.

The chief disadvantage of the jack-up is its vulnerability when being jacked up or relocated, but as a class, they are cheaper than other mobile rigs. Nearly half of the world's fleet of offshore rigs are of the jack-up type.

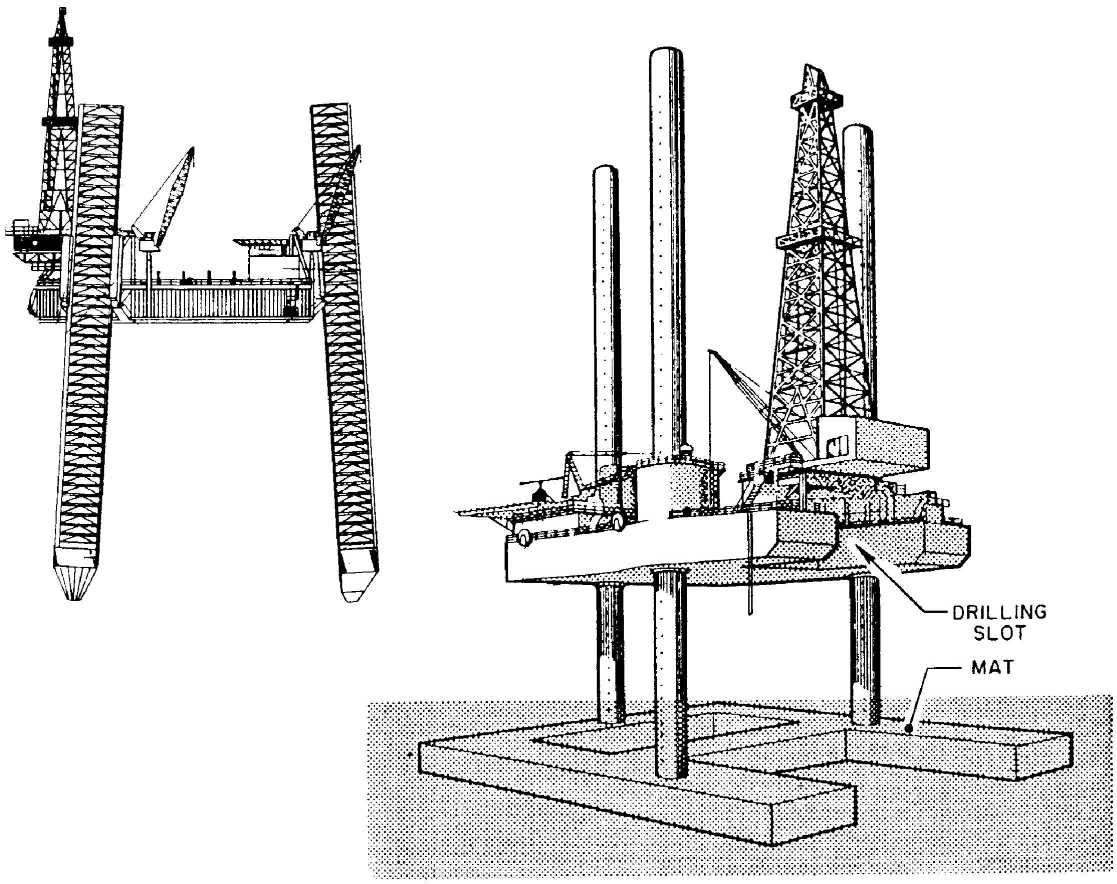

Figure 3-3: Jack-Up Rigs

Fixed Platform

There are two basic types of fixed platforms: “piled” steel platforms and “gravity structures”. Both types are discussed below.

Piled Steel Platforms

These are conventional drilling and production platforms, and hundreds of them are installed offshore in many parts of the world. The standard configuration (Figure 3-4) consists of a steel jacket pinned to the seabed by long steel piles, surmounted by a steel deck which supports equipment and accommodation buildings or modules, one or more drilling rigs, and a helicopter deck.

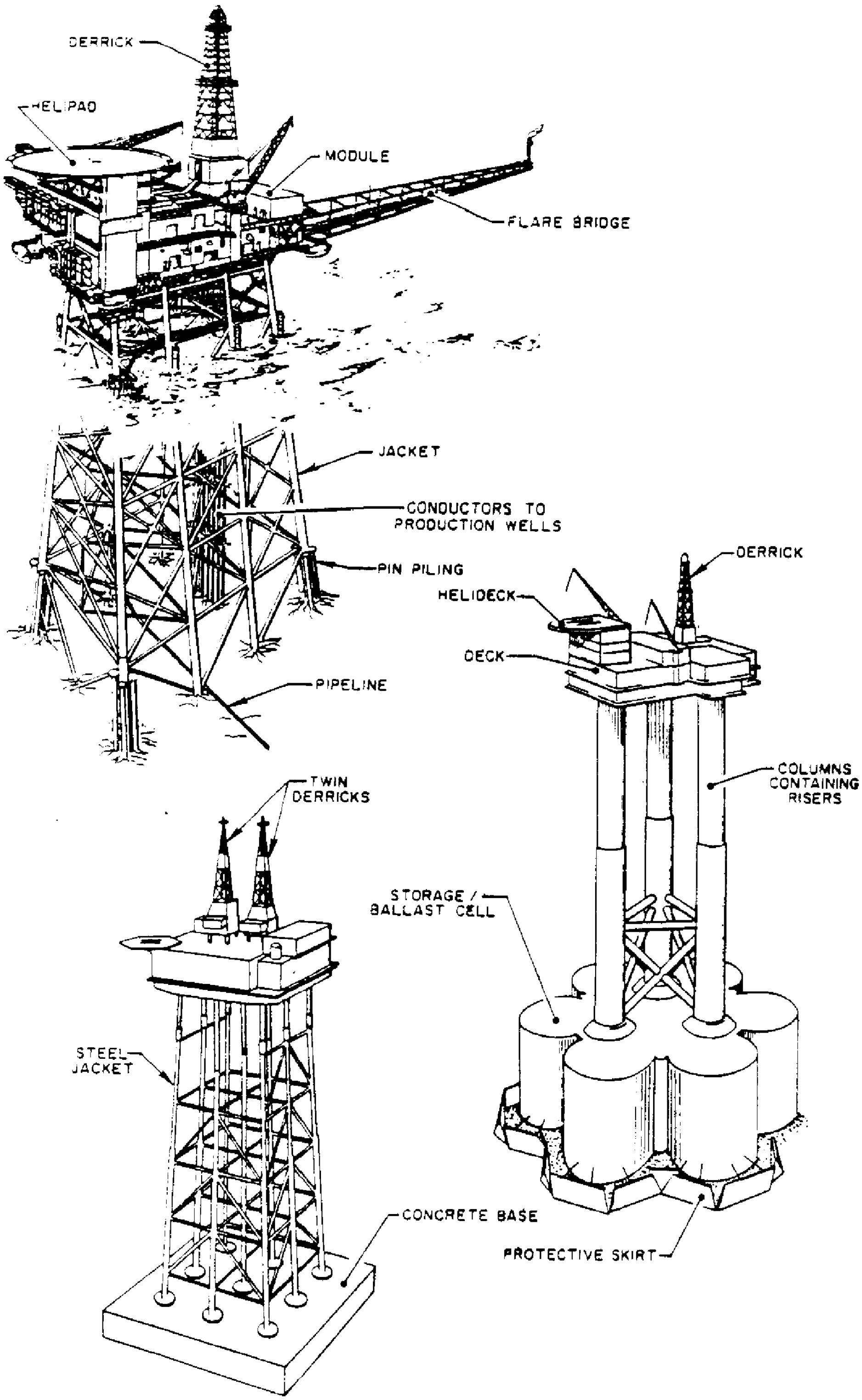

Figure 3-4: Fixed Platforms

Piled steel platforms have the advantage of being very stable under the worst sea conditions, but they are virtually immobile. In shallow waters the piled platform is probably preferred over all other designs, but they are also practical in very deep water. Construction of the jacket in separate sections usually begins onshore. They are then assembled on a flotation jacket, either onshore or in a graving dock. When completed, the structure is carefully towed to its destination where it is first tilted upright by adjusting the ballast in the flotation tanks, and finally submerged over the chosen spot on the sea bed. The jacket is then pin-piled, the “superstructure” and accommodation modules erected, and the platform made ready for operations.

Gravity Structures

This is a family of deep-water structures usually built of reinforced concrete, but may be of steel or a combination of steel and concrete. These structures rely on gravity to keep them stable on the seabed. Unlike piled steel platforms, they are relatively mobile and need no pilings to hold them in place. Gravity structures tolerate a wide range of seabed conditions. While they can be used for development drilling and production, they also have the advantage of being able to store oil in their structure cells. A typical gravity structure (Figure 3-4) consists of a cellular concrete or steel base for storage or ballast, a number of vertical columns which support a steel deck and give access to the risers, and deck accommodations in the form of detachable modules. Construction of the concrete type begins in a dry dock basin where the base caisson is partly built. The basin is then flooded and the base towed into deeper water where the caissons are finished, the towers are formed, and the deck installed. Steel structures are assembled in the same manner as piled steel platforms, and all types are towed to their final destinations and settled upright on the seabed by controlling ballasting. Deck modules are then lifted onto the deck and fitted out, after which the platform is ready for operations. There are several configurations of gravity structure, each of which is constructed to client requirements.

Semi-Submersible

These are floating drilling rigs consisting of hulls or caissons which carry a number of vertical stabilizing columns and support a deck fitted with a derrick and associated drilling equipment. Semi-submersible drilling rigs differ principally in their displacement, hull configuration, and the number of stabilizing columns. Most modern types have a rectangular deck, a few are cruciform shaped, others pentagon shaped, while some of the smaller rigs have a triangular deck. The most usual hull arrangement consists of a pair of parallel rectangular pontoons which may be blunt or rounded and house thrusters for position-keeping or self-propulsion, although some

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have individual pontoons or caissons at the foot of each stabilizing column or pair of columns. Eight columns (four stabilizers and four intermediate columns) is a common arrangement as are three and six columns, and both hulls and columns are used for ballasting as well as for storing supplies.

The semi-submersible is very stable because its center of gravity is low in the water. It can operate in deeper waters than a jack-up rig. Operational depth is limited principally by the mooring equipment and by riser handling problems, so most semi-submersibles have a limit of between 600 feet. However, some have a capability of drilling in 1500 feet of water with the aid of "dynamic positioning". This is a method of maintaining the position of a vessel with respect to a point on the seabed by activating on-board propulsion units in response to signals received from a position-error detector. This method of automatic stationing is often computer controlled.

Figure 3-5a shows a semi-submersible rig with independent pontoons, and Figure 3-5b shows a semi-submersible with ship-shaped hulls.

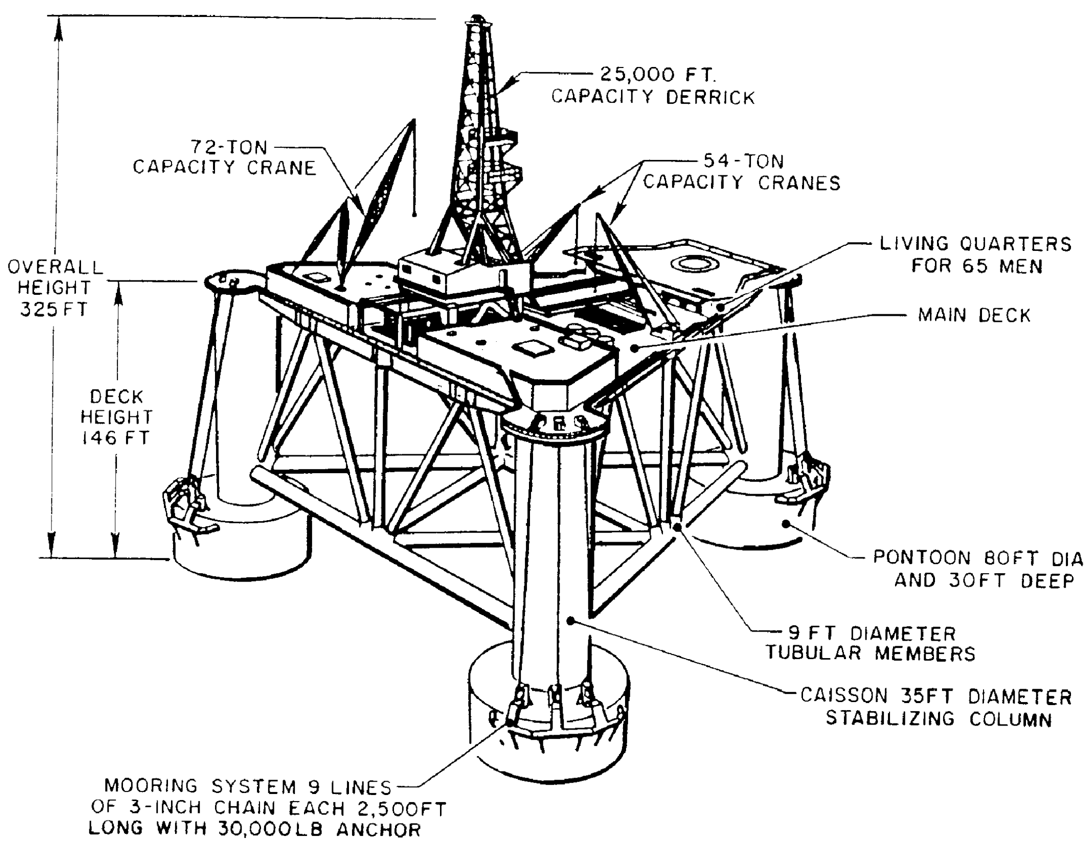

Figure 3-5a: Semi-submersible - Pontoon Type

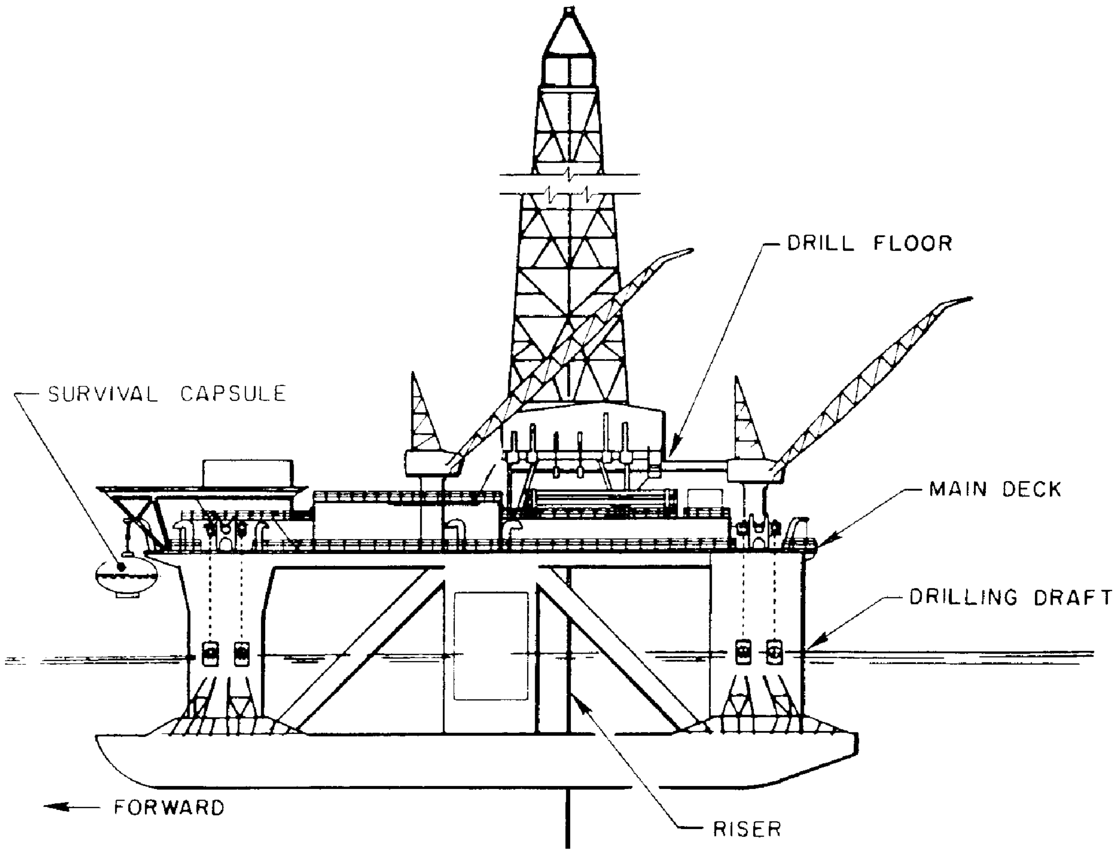

Figure 3-5b: Semi-Submersible - Twin Hull Type

Drillship

These are ships or “floaters” specially constructed or converted for deep-water drilling. Drillships offer greater mobility than either jack-up or semi-submersible rigs, but are not as stable when drilling. Their main advantage is an ability to drill in almost any depth of water. Many are anchor-moored, but modern ships are fitted with dynamic positioning equipment which enables them to keep on-station above the borehole. Having greater storage capacity than other types of rigs of comparable displacement, drillships are often able to drill deeper wells and operate independent of service and supply ships. A feature of drillships with automated station-keeping facilities is their ability to maneuver accurately with the aid of thrusters fitted with controllable pitch propellers. The drilling slot (moon pool) on a drillship is through the center of gravity, and the derrick mounted above it gives the drillship its distinctive appearance, as seen in Figure 3-6.

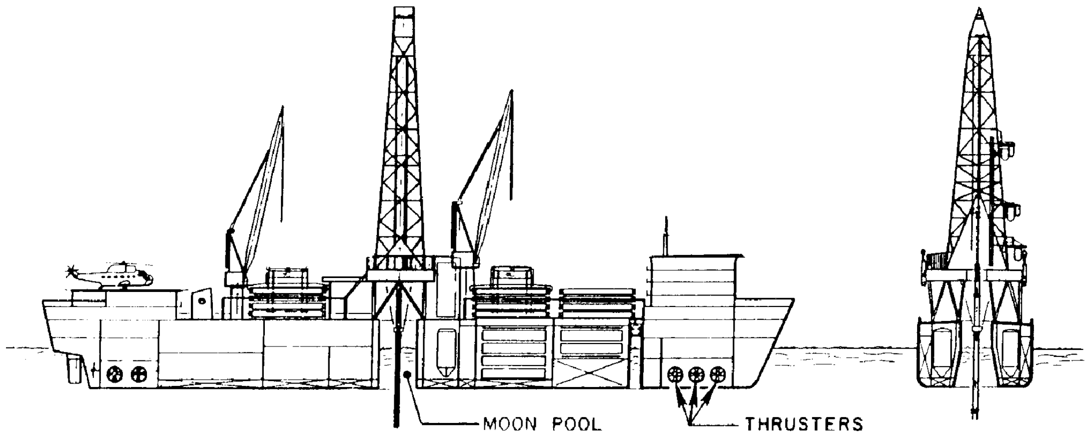

Figure 3-6: Drillship

Rig Components

The principal components of a rig are shown in Figure 3-7. The rig is basically comprised of a derrick, the drawworks with its drilling line, crown block and traveling block, and a drilling fluid circulation system including the standpipe, rotary hose, drilling fluid pits and pumps.

When drilling is progressing, the kelly (or drillpipe) is suspended from the hook beneath the traveling block, and the swivel allows the drillstring to be rotated in the rotary table while conveying the drilling fluid inside the drillpipe into the borehole.

These components work together to accomplish the three main functions of all rotary rigs:

- Hoisting System
- Circulating System
- Rotating System

Two other systems, although not associated with the drilling process, must be mentioned when considering rig components:

- Motion Compensation System
- Blowout Prevention System

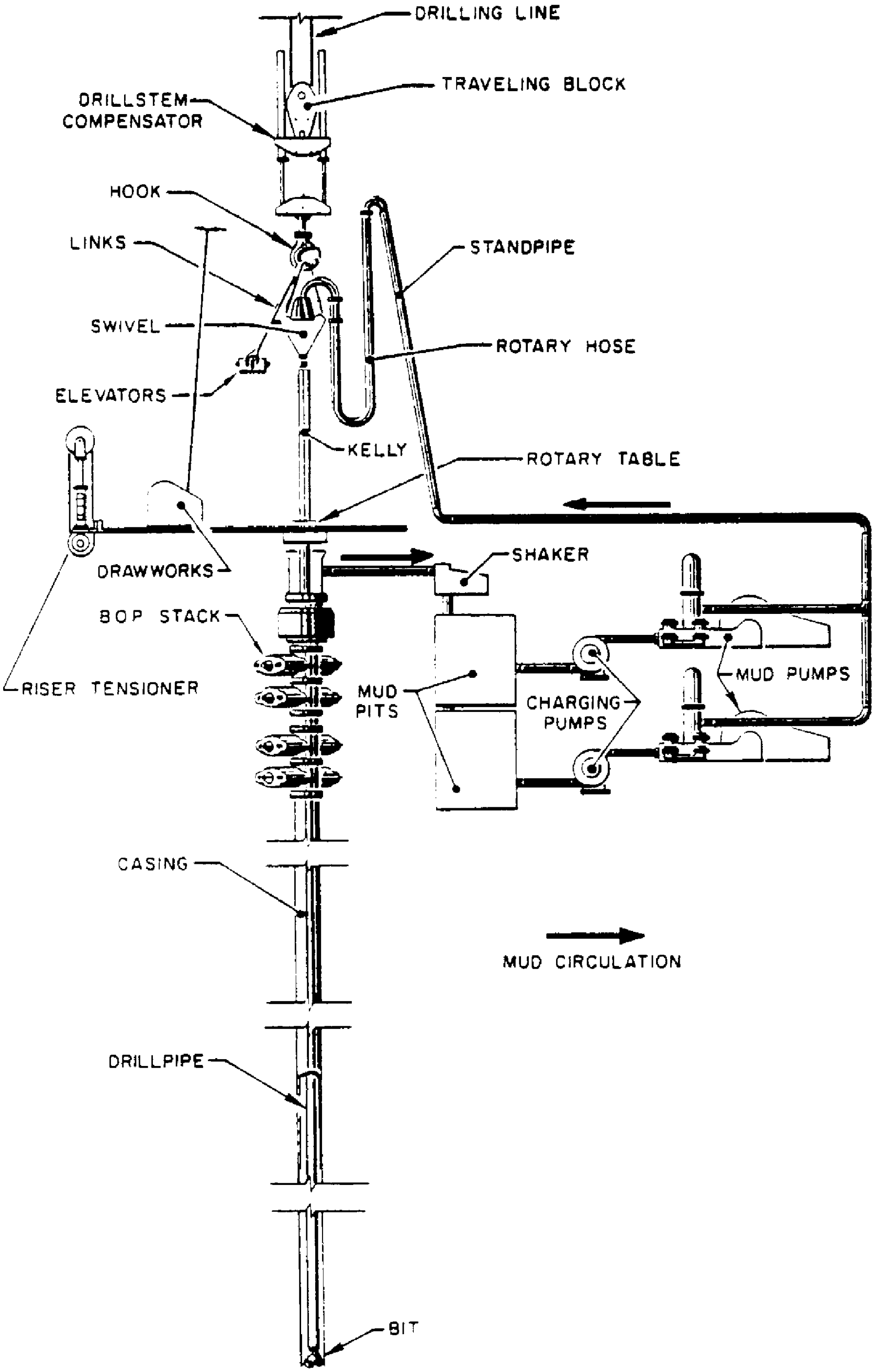

Figure 3-7: Diagrammatical Display of Rig Components Showing Circulation System

The Hoisting System

The mast or derrick supports the hook and elevators by means of the traveling block, drilling line, crown block and drawworks. The drawworks is powered by prime movers - usually two, three or even four engines.

Derrick or Mast: Whenever the drillstem is suspended by the traveling block and drill line, the entire load rests on the derrick (Figure 3-8). The standard pyramid derrick is a structure with four supporting legs resting on a square base. In comparison, a mast is much more slender and may be thought of as sitting on one side of the rig floor or work space.

The derrick is erected on a substructure which supports the rig floor and rotary table and provides work space for the equipment on the rig floor. The derrick and its substructure support the weight of the drillstem at all times, whenever it is suspended from the crown block or resting in the rotary table. The height of the derrick does not affect its load-bearing capacity, but it is a factor in the length of the sections of drillpipe that can be removed. The drillstem must be removed from the borehole from time to time, and the length of each drillpipe section to be removed is limited by the height of the derrick. This is because the crown block must be sufficiently elevated above the rig floor to permit the withdrawal and temporary storage in the derrick of the drillstring when it is pulled from the borehole to change the bit or for other reasons.

Traveling Block, Crown Block, Drill Line and Hook: The traveling block, crown block and drill line (illustrated in Figures 3-7, 3-8, and 3-9) are used to connect the supporting derrick with the load of drillpipe to be lowered into or withdrawn from the borehole. During drilling operations, this load usually consists of the weight of the drillpipe, drill collars and drill bit. The drill line passes from the drawworks to the top of the derrick. From here is sheaved between the crown block and traveling block to give an eight, ten or twelve-line suspension. It is then clamped to the rig floor by the deadline anchor. The drill line is “slipped” (moved) periodically so that it wears evenly as it is used. Cutoff procedures take into account the amount of usage - that is, ton-miles of service. If the drill line has moved a one-ton load a distance of one mile, then the line has received one ton-mile of usage.

Suspended from the travelling block, on standard drilling systems, is the hook which when drilling carries the swivel and kelly (Figure 3-9) and when tripping it lifts the drillstring with the elevators. The elevators are attached to the hook using the links.

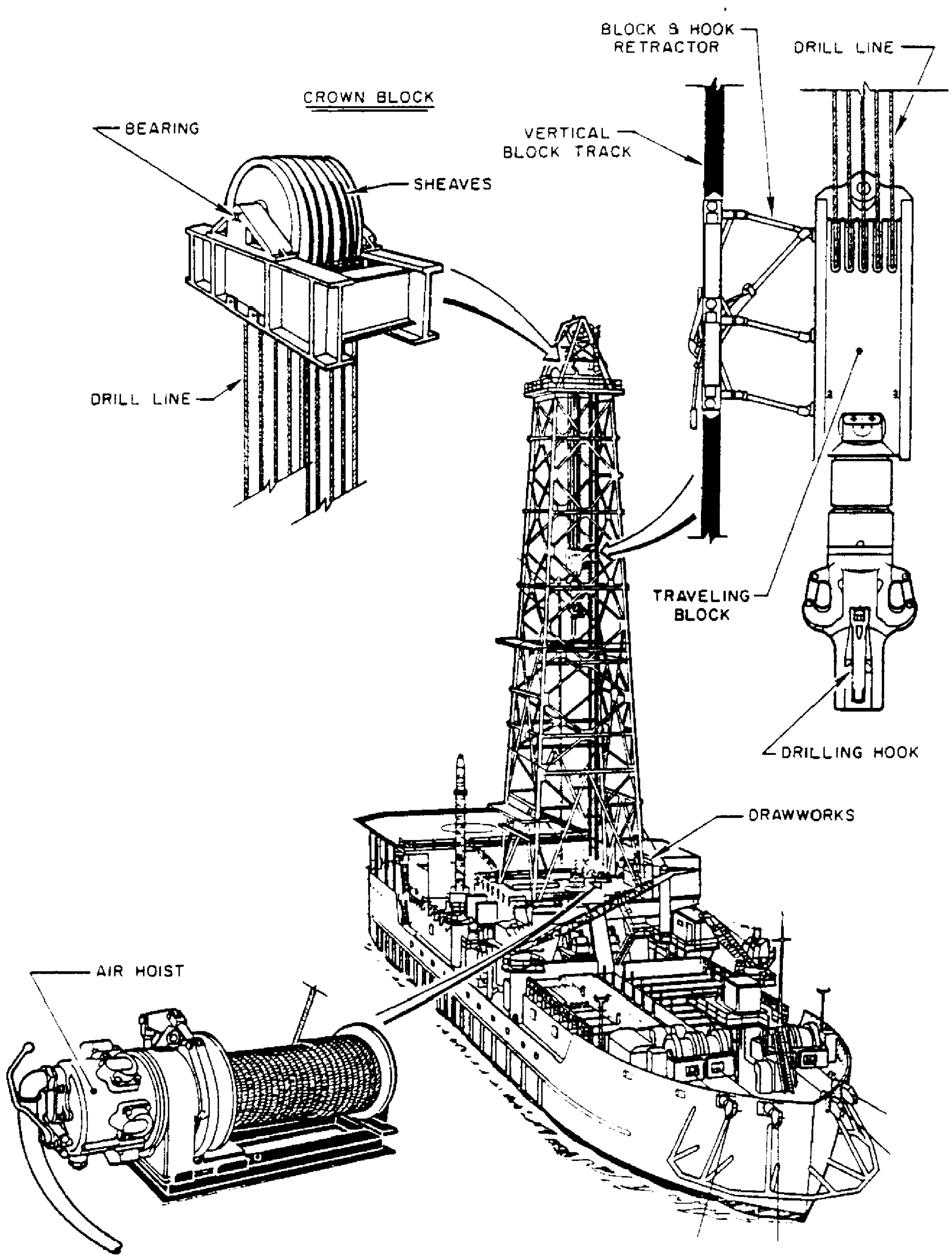

Figure 3-8: Hoisting System Components

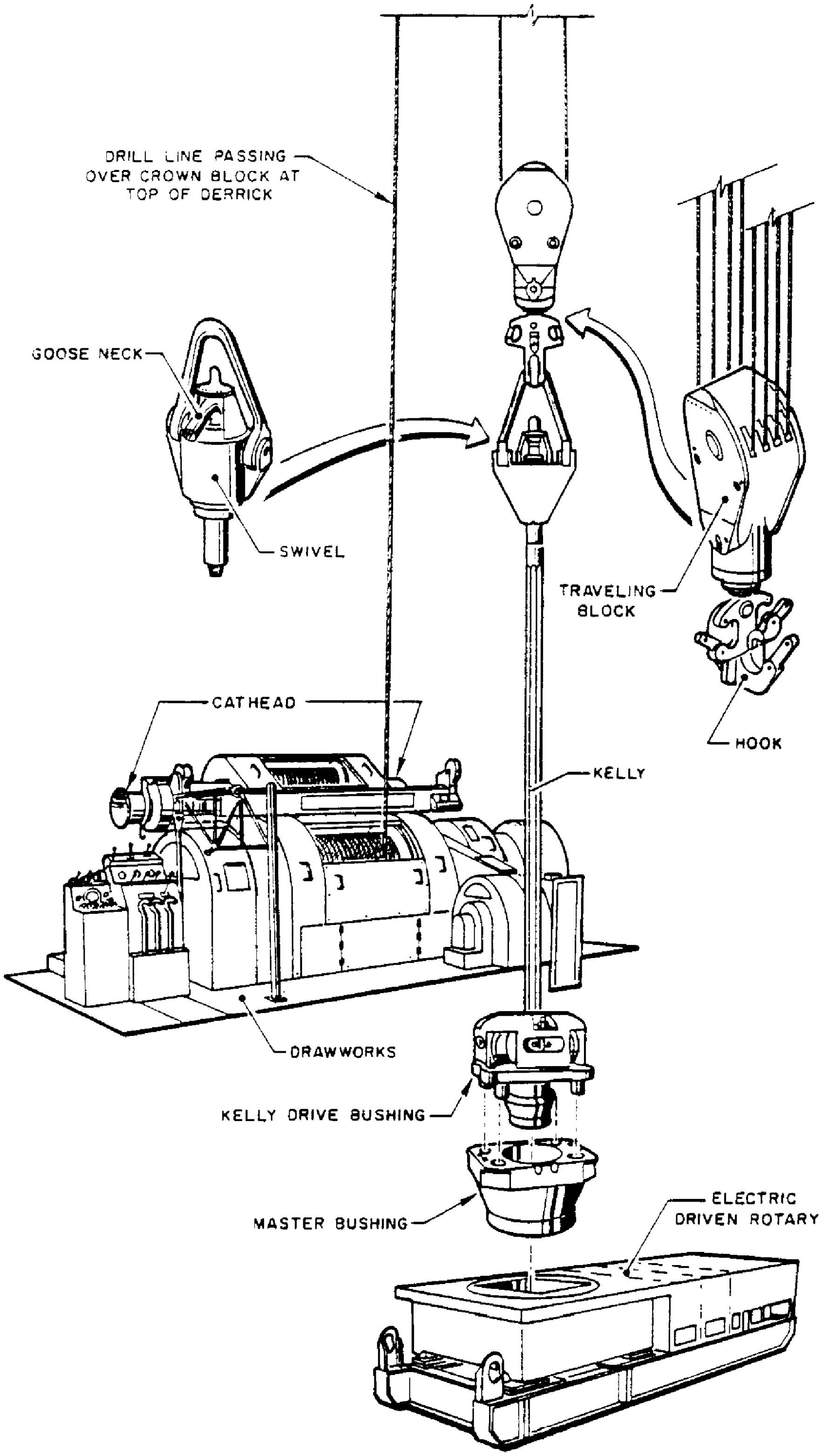

Figure 3-9: Hoisting and Rotary Components

The Drawworks: The drawworks is a mechanism commonly known as a hoist. Figure 3-9 shows the drawworks for a heavy-duty rig. The main purpose of the drawworks is to lift the drillstring out of and to lower it back into the borehole. The drill line is reeled (spooled) on a drum in the drawworks. When engaged, the drum turns and either reels in the drill line to raise the traveling block, or lets out the drill line to lower it. Because the drillstem is attached to the block, it is raised or lowered.

One outstanding feature of the drawworks is the brake system, which enables the driller to easily control a load of thousands of pounds of drillpipe or casing. On most rigs, there are at least two brake systems. One brake is a mechanical friction device and can bring the load to a complete stop. The other brake is hydraulic or electric; it can control the speed of the descent of a loaded traveling block, but is not capable of bringing it to a complete stop. It is used to reduce the wear on the primary friction system.

An integral part of the drawworks is the gear (transmission) system. This gives the driller a wide choice of speeds for hoisting the drillstring.

The drawworks also has a drive sprocket that drives the rotary table by means of a heavy-duty chain. In some cases, however, the rotary table is driven by an independent engine or electric motor.

Another feature of the drawworks are the two catheads. The make-up cathead, on the drillers side, is used to spin up and tighten the drillpipe joints. The other, located opposite the driller's position on the drawworks is the breakout cathead. It is used to loosen the drillpipe when the drillpipe is withdrawn from the borehole.

An independent air hoist (Figure 3-8) is used on many rigs for handling light loads around the rig-floor.

Circulating System

When drilling is in progress (Figure 3-7), the components of the hoisting system, mud pumps and prime movers are used to circulate drilling fluid from the mud pits through the drillstring and out the bit. Cuttings are flushed from the bottom of the borehole up to the surface, thus cleaning the bottom of the hole and providing the logging geologist with samples at the surface.

Mud Pumps: A drilling rig usually has two mud pumps, and these are the heart of a fluid-circulating system. Their function is to circulate the drilling fluid under pressure from a surface pit, through the drillstem, to the bit, return it up the annulus, and back to the pit. Mud pumps are either duplex, double-acting reciprocating pumps or triplex, single-acting pumps.

In duplex pumps, each of the two cylinders is filled on one side of the piston at the same time fluid is being discharged on the other side of the

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piston (see Figure 3-10). Each complete cycle of the piston results in the discharge of a fluid volume that is twice the volume of cylinder, minus the volume of the rod. The total volume for a duplex pump in one complete cycle is twice this amount because there are two pistons. The volume of fluid pumped per minute is determined by multiplying the volume per complete cycle by the number of strokes/cycles per minute. Strokes per minute (spm), on a duplex pump actually means cycles per minute, because the double acting, twin cylinders stroke four time during each cycle.

Triplex single-acting pumps (Figure 3-10) put pressure on only one side of the piston. These pumps have three pistons and are much lighter than duplex pumps for specific power ratings. More power can be obtained from a relatively small triplex pump because it operates at higher speeds, 120 to 160 spm as compared to 60 to 70 spm for a duplex. Because triplex pumps operate at higher speeds, they usually have a centrifugal pump to charge the suction. With a properly charged suction, triplex pumps can operate at nearly 100% volumetric efficiency. When efficiency problems are discovered, it is usually because of problems with the suction pump.

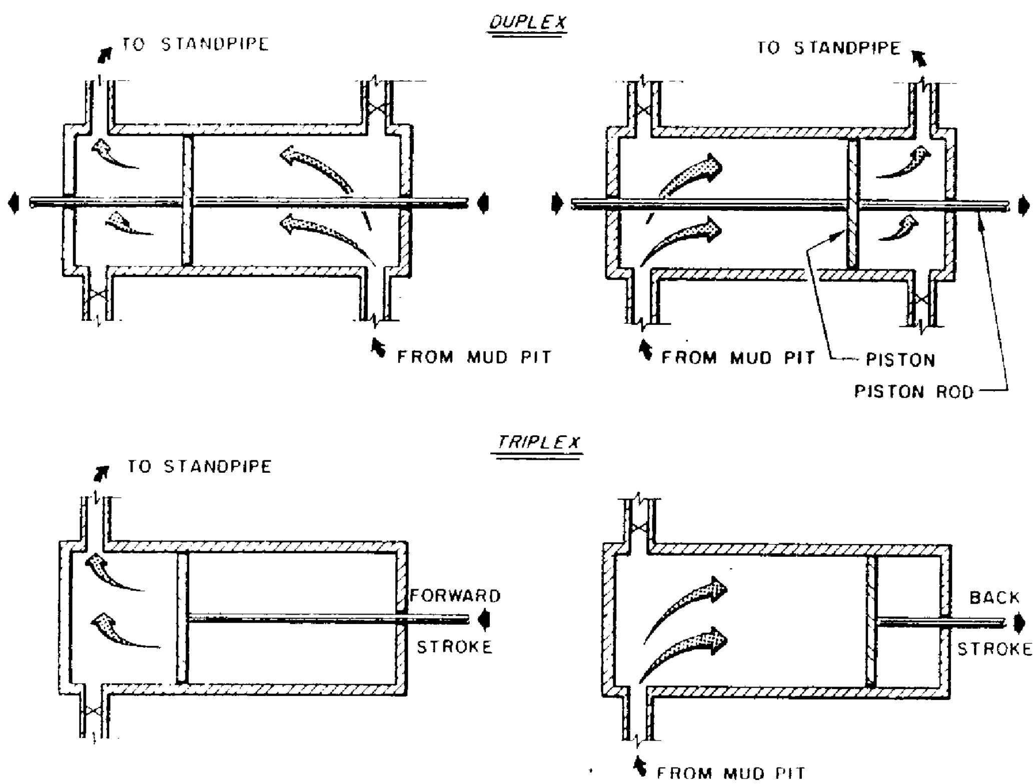

Figure 3-10: Schematic Cross-Section of Duplex and Triplex Mud Pumps

Standpipe and Rotary Hose: In addition to the mud pumps, the surface portion of the fluid circulating system consists of high pressure piping from the pumps to the standpipe (Figure 3-7). The standpipe is firmly clamped to the derrick and topped with a gooseneck fitting. The standpipe anchors one end of the rotary hose and keeps the hose clear of the rig floor when the drillstem is lowered during drilling. The other end of the rotary hose is connected to a gooseneck on the swivel.

Drillstem

The drillstem consists of three main components:

- Kelly and Swivel - on a rotary table system, or Power Swivel - on a top drive system
- Drillstring (drillpipe and bottom-hole assembly)
- Drill Bit

Together they perform the following functions:

- Lower the bit into the hole and withdraw it.
- Place weight on the bit so it can penetrate the formations more effectively.
- Transmit a rotating action to the bit.
- Conduct the drilling fluid under pressure from the surface to the bit.

Kelly and Swivel: The upper end of the drillstem terminates where the top-most length of drillpipe screws onto a device called a saver sub. This sub is used to save wear and tear on the threads of the kelly. The kelly is approximatel 40 feet long, square or hexagonal on the outside and hollow throughout to provide a passage way for the drilling fluid. Its outer surfaces engages corresponding square or hexagonal surfaces in the kelly bushing. The rotary system activates the kelly bushing which, in turn rotates the kelly. The kelly moves freely up and down through the kelly bushing, even when rotating. Figure 3-9 illustrates the arrangement of the kelly, kelly bushing and rotary system. At the top of the kelly there is usually a “kelly cock valve” - a safety valve which can be closed to prevent fluid back pressure from damaging the swivel, rotary hose and other surface equipment.

The swivel, which is attached to the hook, does not rotate. It supports the kelly, which does rotate. Drilling fluid is introduced into the drillstem through a gooseneck connection on the swivel, which is connected to the rotary hose.

Power Swivel: When a “top-drive” system is used, the kelly is replaced by a stand of drillpipe. The power swivel performs the same functions as the

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"normal" swivel, but it is also associated with a transmission system used to rotate the drillstring, instead of the rotary table transmitting this motion.

Drillstring: The drillstring is made up of the drillpipe, drill collars, and specialized subs through which the drilling fluid and rotational power are transmitted from the surface to the bit.

1. Drillpipe: American Petroleum Institute (API) drillpipe and other tubular products are gauged by the nominal outside diameter (O.D.) of the tube. The O.D. of a given pipe must be a specific measurement in order for threaded fittings and pipe-handling tools, such as elevators and slips, to fit properly. Although the O.D. of API drillpipe is the same for each size, the inside diameter (I.D.) varies with the nominal weight per foot of length. API drillpipe is also "upset" (made thicker) on the ends for added strength. Here the tool joints are shrunk or welded-on to enable lengths of drillpipe to be screwed together to make up the drillstring. The three types of API upset dimensions are in Figure 3-11.

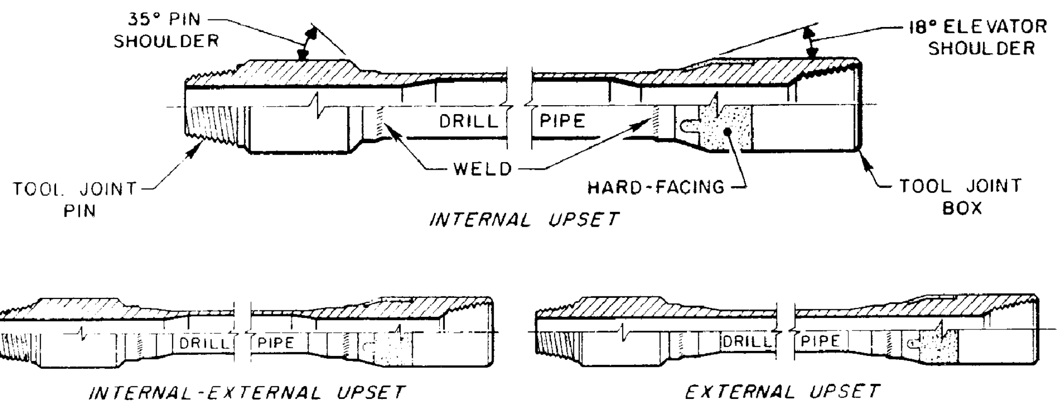

Figure 3-11: API Drillpipe with Weld-on Tool Joints

Upsets are necessary on drillpipe, both for shrink-on or weld-on tool joints, to provide safety in the weld area for mechanical strength and metallurgical considerations. API seamless drillpipe is offered in five grades of steel, varying in strength from D (the weakest) through E, X, G to S (the strongest). High strength drillpipe requires heavier and longer upsets than those used on grades D and E.

Lengths of drillpipe are generally between 31 to 45 feet, and are usually measured to the hundredth of a foot.

2. Heavy-Weight Drillpipe: This tubing product is an intermediate sized drillpipe, having the same nominal O.D. as drillpipe, but having a smaller I.D. (thus giving it more strength). The tool joints are also slightly larger than drillpipe. There may be a

"wear pad" located on the center of the pipe to assist in stability and rigidity.

Heavy-weight drillpipe is placed below the length of drillpipe on the drillstring.

3. Drill Collars: These are similar to drillpipe, but have larger outside diameters (up to 10 inches) and have small inside diameters. They, also, are approximately 30 feet long. Drill collars have several important functions to perform:

- Provide weight to the bit when drilling
- Maintain weight to hold the drillpipe in tension
- Provide the pendulum effect to cause the bit to drill a nearly vertical hole
- Provide rigidity in order to drill a new hole aligned with the previously drilled hole

Any drillstring weighs less in the drilling fluid than in air due to the buoyancy effect of the drilling fluid. The actual weight of the length of collars in the drilling fluid is determined using:

Buoyed Weight = total weight of collars x [1 - (0.015 x mud density)]

The denser the mud, the greater the buoyancy effect, and the lighter the apparent weight of the drill collars. This is important when deciding how many collars to run, because total drill collar weight must exceed that which is applied to the bit when drilling, so that no weight is applied to the drillpipe (this is the main reason for adding heavy-weight drillpipe to the drillstring). In this way, the lower portion of the collars are in compression, with the weight resting on the bit, and the upper portion of the drillstring remains in tension supported by the hook. It is vital that the drillpipe never be subjected to compression, as it would bend and "twist-off" very easily. Figure 3-12 shows how adequate drill collar weight keeps the drillpipe in tension while providing weight to the bit while drilling.

The pendulum effect is the tendency of the drillstring to hang in a vertical position due to the force of gravity. The heavier the pendulum, the stronger the tendency to remain vertical and the greater the force needed to cause the drillstring to deviate from vertical.

The length of the pendulum is that section of the drill collar section between the bit and the lowest point tangent to the side of the borehole. It is desirable that the pendulum be as long as possible, for it then has a greater tendency to seek a vertical position.

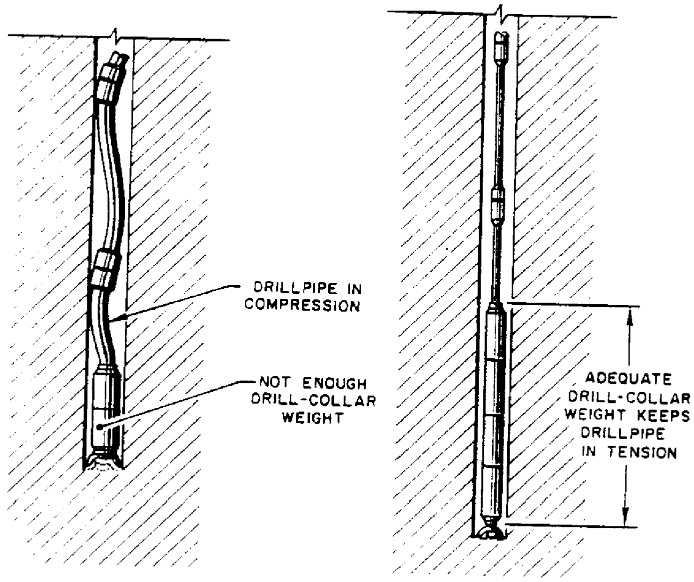

Figure 3-12: Drill Collar Weight

Large, heavy drill collars immediately above the bit stabilize the drillstring in the borehole and cause the bit to drill a rifle-bore extension to the well, in spite of the uncontrollable forces that tend to deviate the borehole (such as dip of the formations, formation type, etc.). Packed-hole assemblies, using oversized or square collars, frequently with stabilizers, guide the bit to drill a true extension. The term “packed-hole” refers to the fact that the drill collars in the lower portion of the assembly are about 0.5 inches smaller in diameter than the borehole. This does make the drillstring susceptible to problems and various design features (such as spiral grooving, square sections, etc.) are incorporated in drill collars to prevent this.

Bit stabilization enables hole alignment and ensures proper bit performance by causing the bit to rotate on its axis. This prevents the bit from wobbling or walking on bottom and uniformly loads the cutting structure of the bit. An unrestrained bit may drill an oversized hole, produce unusual bit wear, and slow down the rate of penetration. Bits drill faster and last longer when properly stabilized.

In contrast to drillpipe, the weakest point in drill collars is at the joint, for there are no upsets on a drill collar tool joint.

4. Specialized Subs: The word “sub” refers to any short length of pipe, collar, casing, etc., with a definite function.

- Crossover Sub (XO sub) - A crossover sub is designed with different threaded ends for changes between different sizes and types of drillpipe or collars.
- Shock Sub - This is run behind the bit. It has a steel spring or rubber packing to absorb the impact of the bit bouncing on hard formations, thereby damaging the rest of the drillstring.
- Stabilizers - There are short subs (Figure 3-13) with “fins” which are full borehole size or a fixed amount below gauge. The fins may be aluminum, rubber or steel with tungsten carbide inserts on the edges. These are located between the collars and are intended to maintain a straight hole by keeping the collars centralized. Also, by a scraping action, they maintain a full gauge hole.

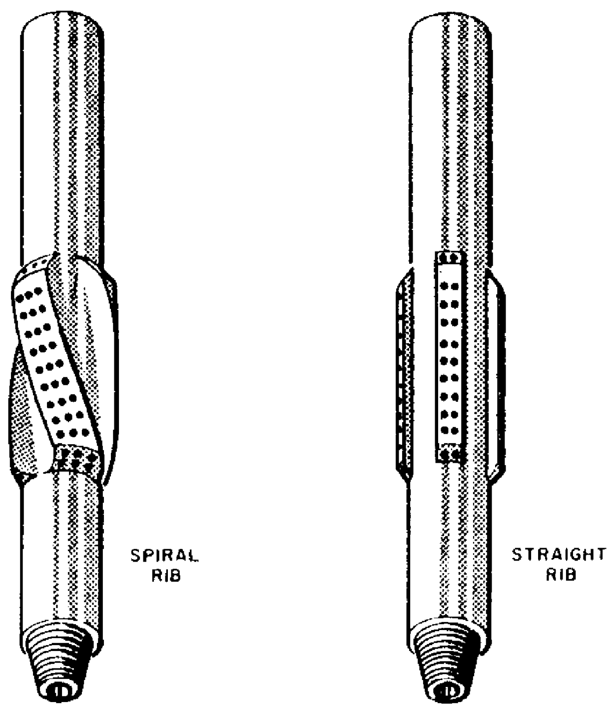

Figure 3-13: Stabilizers

- Bit Sub - This is a short sub with a box on both ends so that the drill bit and collars may be connected to their pin ends.

The term “Bottomhole Assembly” (BHA) is given to the current arrangement of tools incorporated below the drillpipe. The BHA may consist of any arrangement of bit, collars, stabilizers, crossover sub, heavy-weight drillpipe, and other specialized tools.

Drill Bits

The drill bit is probably the most critical item of a rotary rig operation. It is the most refined of the rotary-rig tools, available in many styles, and is more highly specialized for every condition of drilling than any other tool on the rig. To select the proper bit, some information must be known about the nature of the rocks to be drilled. There are two main types of bits used for rotary drilling. There are several variations within these types, primarily based on the cutting structure used for drilling the rock. The two types are:

- Roller Cone Bits
- Fixed Cutter Bits

Two other drilling tools used during rig operations are:

- Reamers
- Hole Openers

Roller Cone Bits

Roller Cone Bits, commonly called tri-cone bits, are the most common bits used today. They are named tri-cone because the cutting structures are located on three rolling cones attached to the bit body. A variety of types are available depending upon any specific conditions involved. Two main categories of tri-cone bits are milled-tooth and insert bits.

1. Milled-Tooth Bits (Figure 3-14): These bits have steel teeth which have been milled on the cones. The teeth vary in size and shape, depending on the formation they are expected to drill. Long, slender teeth are used in soft formations and short, broad teeth are used in harder formations.

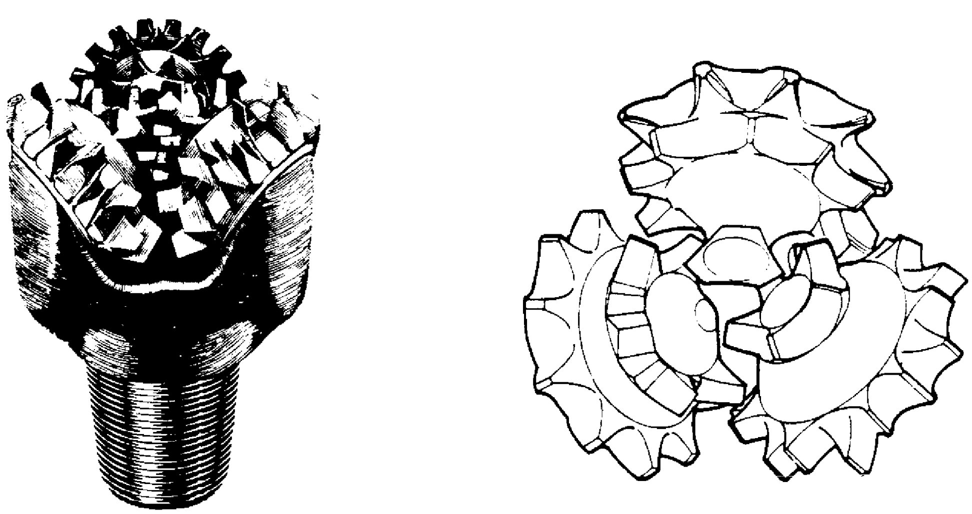

Figure 3-14: Milled Tooth Drill Bit

2. Insert Bits (Figure 3-15): These bits differ from milled-tooth bits in that the cones do not have steel teeth milled into them; instead, tungsten carbide inserts (teeth) are pressed into the cones. These are very much harder and last longer (and much more expensive) when drilling hard formations. The inserts can come in a variety of shapes, from long chisel shapes for firm formations to short round buttons for hard, brittle formations.

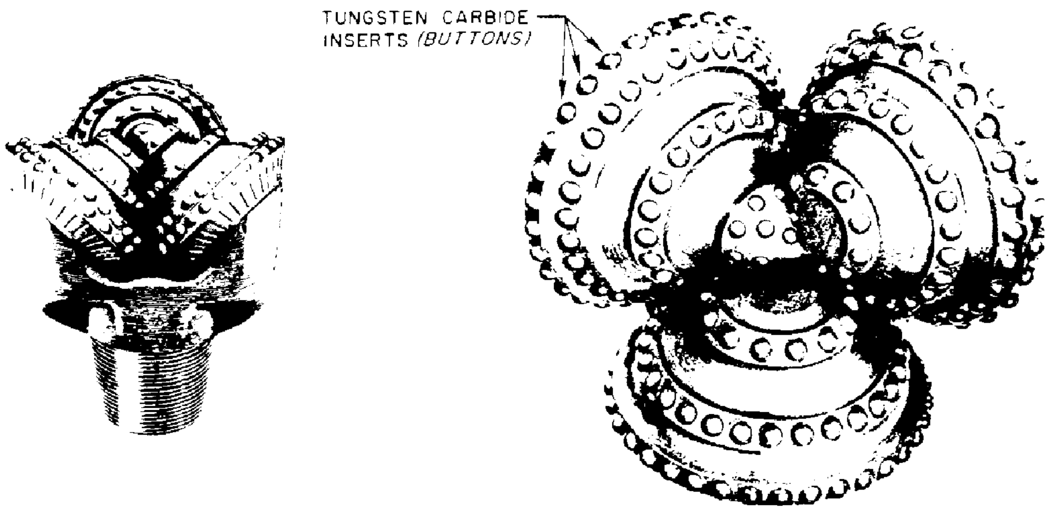

Figure 3-15: Tungsten Carbide (Insert) Drill Bit

Though the cutting structures may differ, tri-cone bits have many common features:

3. Fluid Courses (Figure 3-16): These allow for the drilling fluid to leave the bit and carry away the cuttings. The earliest arrangement was a "conventional" water course, where the fluid passed through holes drilled in the center of the bit body. As wells were drilled deeper, more hydraulic force was necessary to carry the cuttings from the bottom of the hole. "Jet nozzles" were introduced and have been used ever since. Present nozzles come in various sizes which can be changed to match the pressure and flow requirements of the well. Jet nozzles are described in thirty-seconds of an inch (a #10 nozzle is 10/32-inch in diameter).

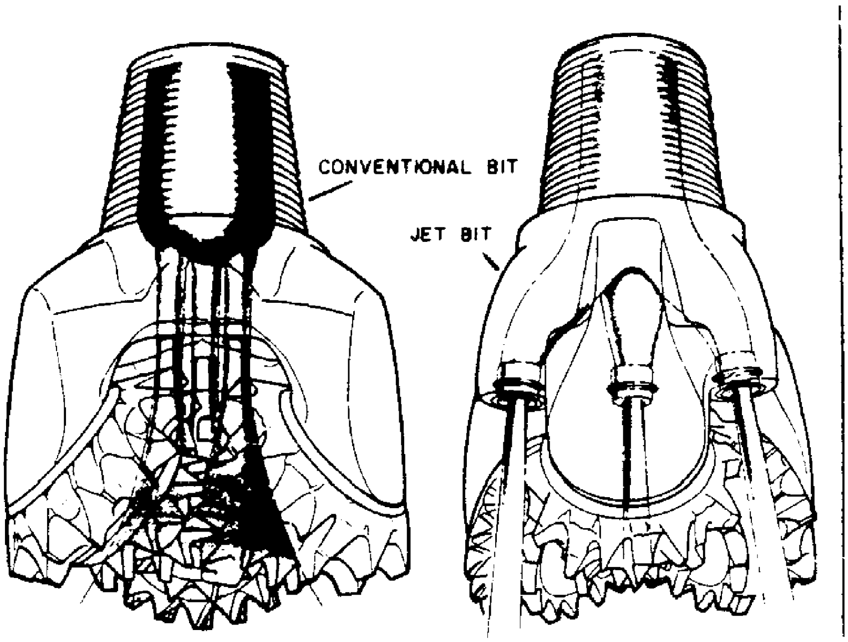

Figure 3-16: Drill Bit Fluid Courses

4. Gauge Protection (Figures 3-17): The outer rows of teeth receive the greatest wear. This is because, if the bit drilled an in-gauge hole, then the outer rows are always in contact with the formations. To compensate for this, bits “protect” these outer row cutting structures. One method is to “hard-face” the bit's teeth with an outer layer of tungsten carbide, another is to “T-shape” a bit tooth to give it a much larger surface. Another method is to press tungsten carbide inserts into the outer row teeth.

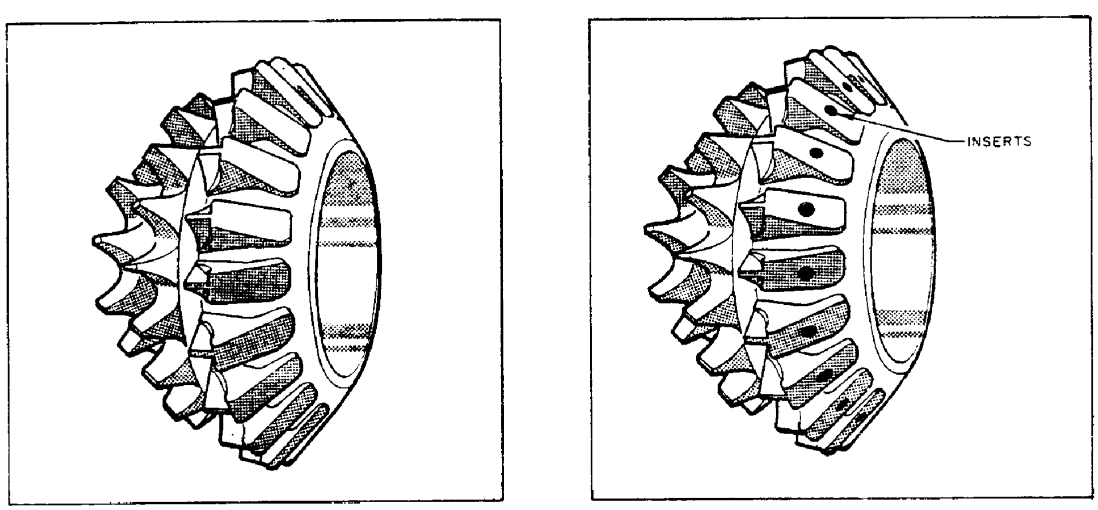

Figure 3-17: Gauge Protection on Bits

5. Journals (Figure 3-18): The journal is the metal shaft upon which the cones are set. They are manufactured for the insertion of bearings, which allow the cones to rotate. The angle, from horizontal, will dictate which type of formation the bit will be used in; 33 to 34 degrees for soft formations, 36 degrees for medium formations, and 39 degrees for hard formations.

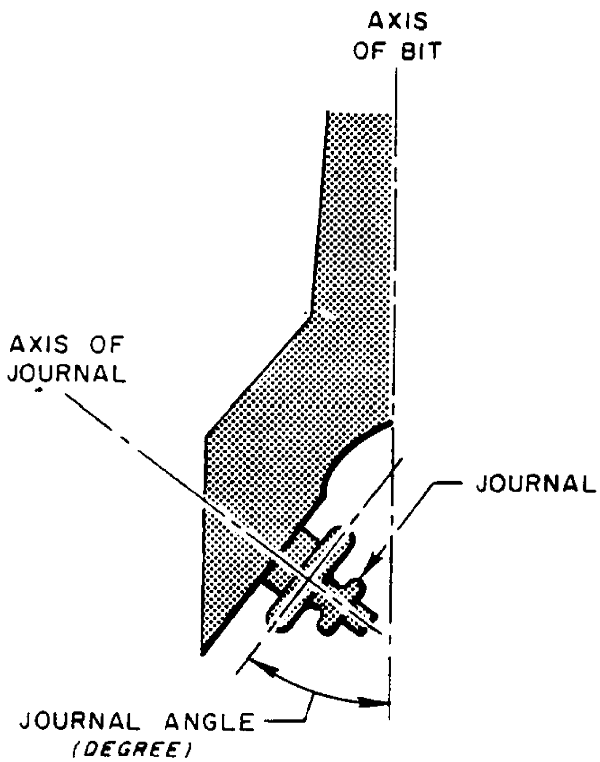

Figure 3-18: Journal Configuration

6. Bearings: Two types of bearings are used in tri-cone bits. Roller/ ball bearings are used when bit life is not a problem. Journal/ friction bearings, a specialized metal ring, enhance the drilling performance because they will last longer. To withstand the pressures and temperatures of drilling, the bearings have to be lubricated. Two types of lubrication are used:

- Non-sealed bearings: This type of lubrication uses the drilling fluid to cool the bearings. However, because of the solid content of the drilling fluid, the bearings do not have a particularly long life.
- Sealed bearings: This lubrication system uses a graphite-type lubricant sealed in a reservoir to cool the bearings. Pressure changes cause the lubricant to be pumped around the bearings.

7. Offset: An off-center alignment of the cones makes the teeth scrape and gouge the formation as the cones rotate. The amount

of scraping depends on the offset. Figure 3-19 shows the cone offset of a soft formation bit. For soft bits, a 1/4-inch to 3/8-inch offset is common. The offset decreases, until hard formation bits have no offset.

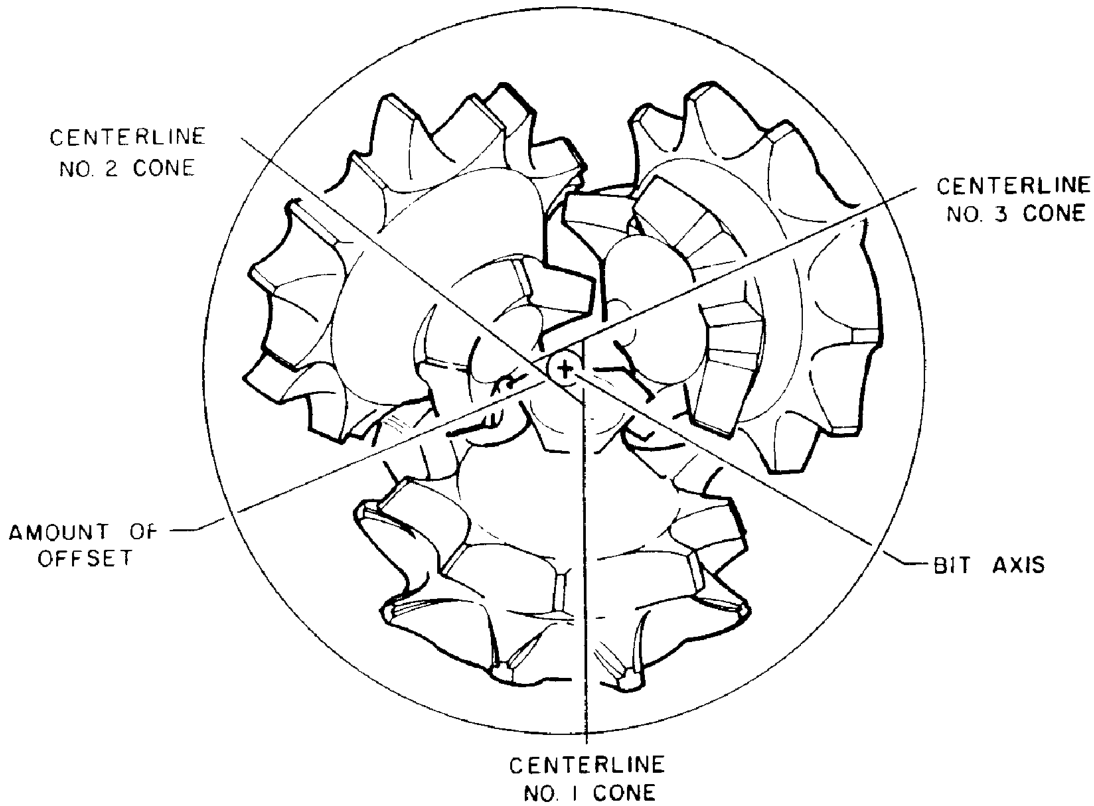

Figure 3-19: Cone Offset

Fixed Cutter Bits

Fixed Cutter Bits have no moving parts. The bit body and cutting structures rotate as one (i.e. there are no cones). These were the earliest type of bits, with the cutting structure still evolving. The main categories of fixed cutter bits are drag bits, diamond bits, PDC (Polycrystalline Diamond Compact) bits, and TSP (Thermally Stable PDC) bits.

1. Drag Bits: This bit (Figure 3-20) was the earliest type. The cutting structure was sharpened steel. As such, it could only be used in soft formations, and is rarely used today.

Figure 3-20: Drag Bit

2. Diamond Bits: These bits use natural diamond (the hardest substance known) as the cutting structure. They are usually slightly smaller than tri-cone bits to prevent diamond damage while being run into the borehole. The design of diamond bits (Figure 3-21) varies greatly in the shape of the head, the size and setting of the diamonds, and the water courses for cooling. The main advantages of diamond bits is that, with no bearings, they can be run for long periods of time and they can drill almost any formation.

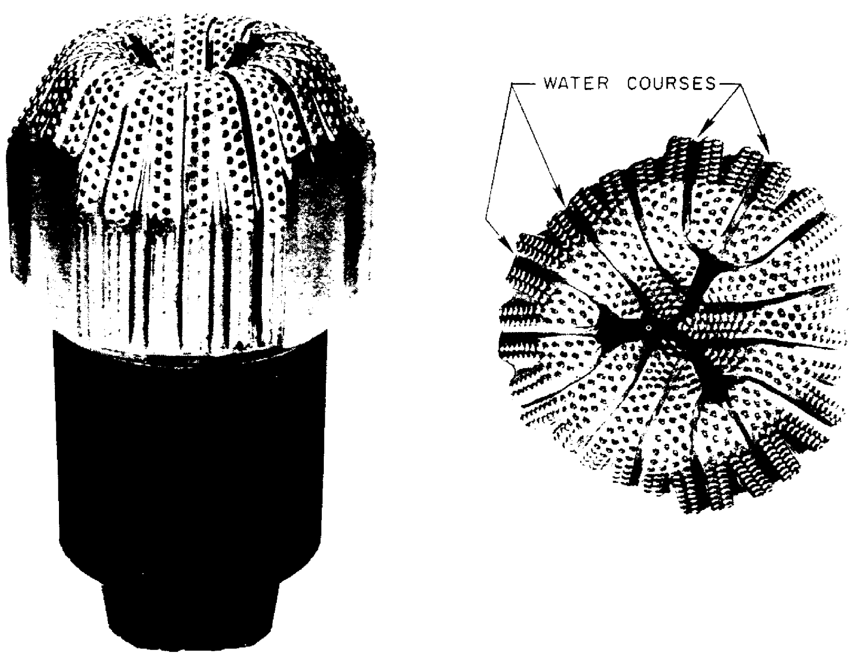

Figure 3-21: Diamond Drill Bit

3. PDC Bits: The cutting structure of these bits is composed of man-made diamond dust/crystals bonded to a tungsten carbide stud. These studs are then either pressed or molded into the bit body. Because of the crystal structure in the cutter, it is self-sharpening (exposing new crystals while others are broken off). They are used in soft to medium-hard formations.

4. TSP Bits: A TSP cutter is composed of the same man-made diamond dust/crystals as a PDC bit. The difference being that the cutters are used by themselves and not bonded to a stud. It has been found that the bonding material is the weakest part of the cutting structure, and under the extremely high temperatures associated with fixed cutter bit drilling, the bonding material loses some its strength and the PDC cutter is broken away from the stud.

Reamers/Hole Openers

Reamers/Hole Openers are tools that are run immediately above a bit to maintain or enlarge the hole size. Their cutting action is by rotating cones built out from the central stem (Figure 3-22). Both types perform similar functions, but the cones of an under-reamer are built into collapsible arms which are held out while drilling by the pressure of the drilling fluid being circulated down through the center of the tool. In this way, it may be run in or pulled out through a smaller section of the borehole.

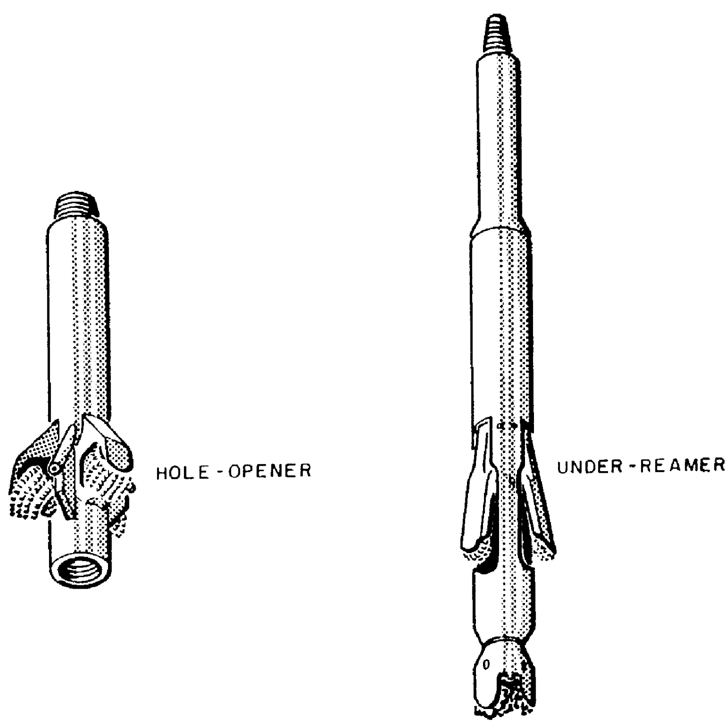

Figure 3-22: Hole Opener and Under-Reamer

Rotating System

This system has undergone the most change in recent years. Rigs now-days may be operating a “conventional” lower rotating system or a “top drive” rotating system.

Lower Rotating System

Operating through kelly drive bushings, the rotary table rotates the kelly and through it the drillstring and bit. Figures 3-9 and 3-23 illustrate the components that make up this rotating system. The kelly drive bushings are driven by four pins which fit into openings in the master bushing, which, in turn, fit into the rotary table.

The Rotary Table: The rotary table serves two main functions:

- It rotates the drillstem
- It holds devices called slips that support the weight of the drillstring when it is not supported by the elevators or hook and kelly.

The rotary drive generally consists of a rotary-drive sprocket and chain, the rotary-drive sprocket being part of the drawworks. However, an independent engine or electric motor with a direct drive to the rotary is often used. In such cases, the rotary is driven by a drive shaft rather than by chains and sprockets.

Master Bushing: Through the master bushing, the rotary table transmits rotary motion to the kelly drive bushing and the kelly. It is also the connecting link between the rotary table and the slips, which supports the pipe during trips. The master bushing and kelly drive bushing can be seen in Figure 3-24.

Kelly Drive Bushing: Also called the “Rotary Kelly Bushing (RKB)”, this bushing engages the master bushing using four pins on the kelly bushing and four corresponding openings in the master bushing. Rollers within the bushing permit the kelly to move freely upwards or downwards when the rotary is turning or stationary. When the kelly is disconnected and is set back, the drive bushing lifts and is set back with it.

Top Drive Rotary System

So called because all drillstem rotation is accomplished by a drive motor located below or attached to the swivel. With such a system the kelly and kelly bushing are not required, and the master bushing and rotary table serve only as conduits for the drillstring to be raised or lowered into the borehole. Because the kelly is not required, stands of drillpipe are drilled instead of single joints.

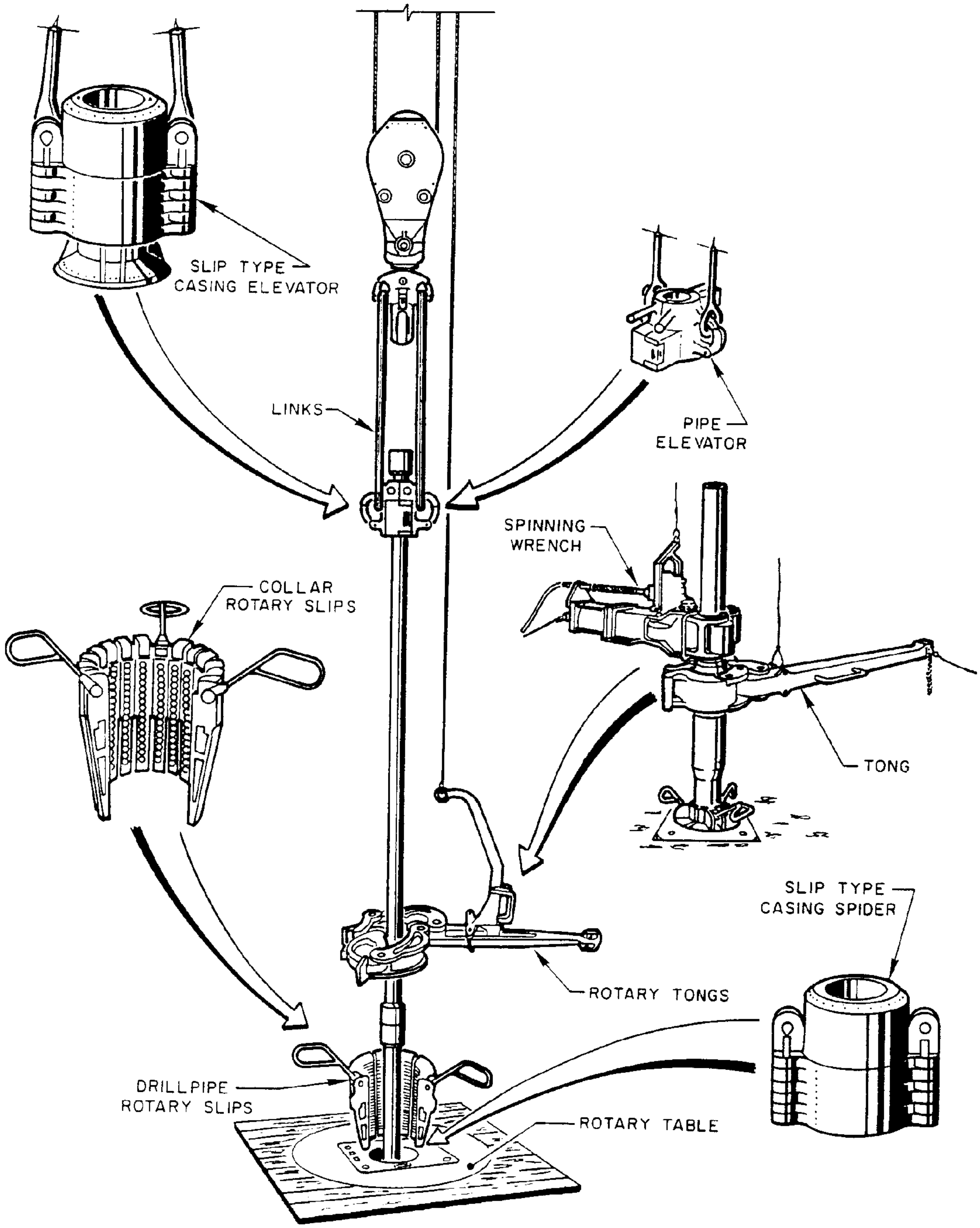

Figure 3-23: Rig Components Used for Pipe Handling

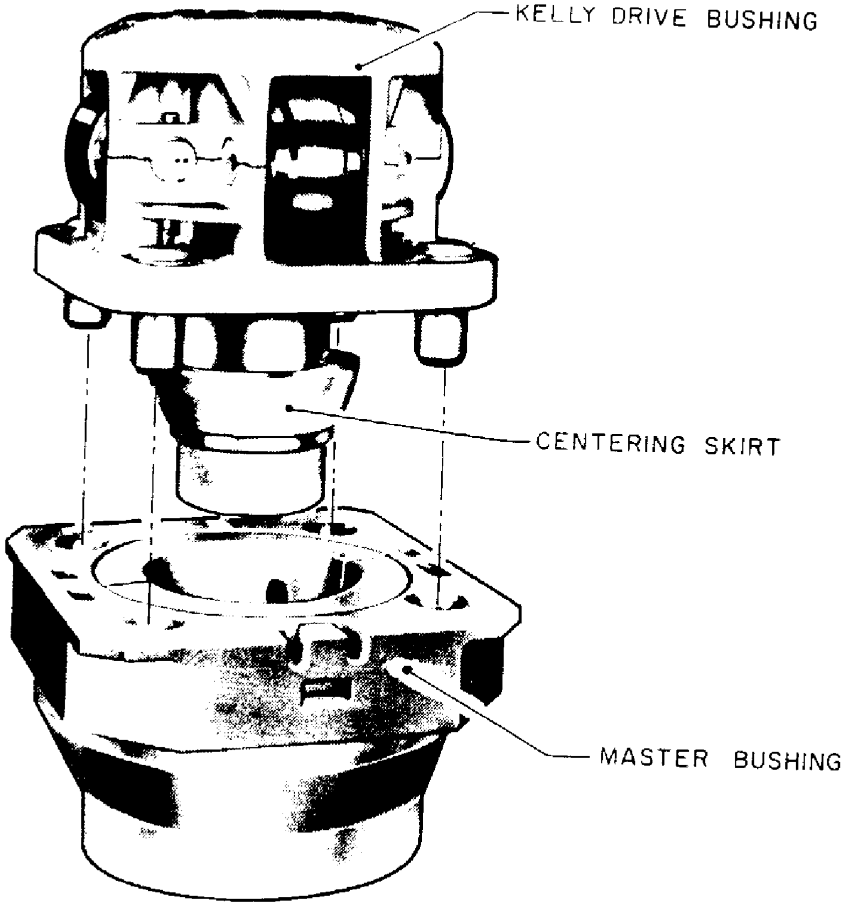

Figure 3-24: Master and Kelly Drive Bushing

Drive Motor and Transmission: To provide rotary torque to the drillstem, an electric motor and a simple step-type transmission are used. It is located directly below and attached to the swivel using a drive-sub, allowing normal drilling fluid circulation.

Pipe Handler and Elevators: This comprises a torque wrench, for attaching or releasing drillpipe during drilling or trips and a safety system (either a kelly-cock valve or an internal BOP). Both are controlled by the driller. The elevators are suspended from the elevator links and have a link mechanism for tilting the elevators towards the mousehole or monkey boards for easy attachment or removal of the drillstring.

Guide Dolly: The guide dolly allows for the movement of the top drive system upwards and downwards during drilling and tripping. It is bolted to the transmission housing and swivel, and moves using rollers on the guide rails attached to the derrick.

Three rig-floor tools are common to both rotary drive systems. They allow for the attachment and removal of drillpipe at rig-floor level.

Slips: As can be seen in Figure 3-24 (lower left), slips are wedge-shaped steel dies fitted in a frame with handles, which are placed between the drillpipe and the sides of the master bushing in the rotary table when making a connection or tripping. Their purpose is to support the drillstring and hold it suspended in the borehole.

Tongs: These are a type of wrench (center, Figure 3-24) used for tightening and loosening drillpipe and drill collars. Two sets of tongs are used, one to hold the drillstring and the other to tighten the joint. They are called the “make-up” and “breakout” tongs.

Spinning Wrench: This is a pneumatically-powered wrench (Figure 3-24, right center), used for rapidly spinning the drillpipe or collars when breaking out or making up the pipe. When using the power tongs, the final torque is applied using the “normal” tongs.

Motion Compensation System

This system is used entirely on offshore floating rigs, semi-submersibles and drillships. There are three basic motion compensation components:

- Drillstring Compensator
- Marine Riser and Guideline Tensioner
- Telescopic Joint

Drillstring Compensator: The drillstring compensator system (Figure 3-25) is designed to nullify the effects of rig heave on the drillstring or other hook-supported equipment. It is mounted between the hook and traveling block. The compensator is connected to rig-floor mounted air pressure tanks via a hose loop and standpipe, and is controlled and monitored from the drillers control console.

While drilling, the drillstring compensator controls the weight-on-bit. The driller intermittently lowers the traveling block to account for drill-off (extra hole) and to maintain the compensator cylinder within its stroke capacity, while the drillstring compensator automatically maintains the selected bit weight.

As the rig heaves upward, the compensator cylinders are retracted, and the hook moves downwards to maintain the selected loads. Actually, the hook remains fixed relative to the seabed; the rig and compensator moves, producing relative motion between the hook and rig. The motion of the drillstring is relative to the rotary table.

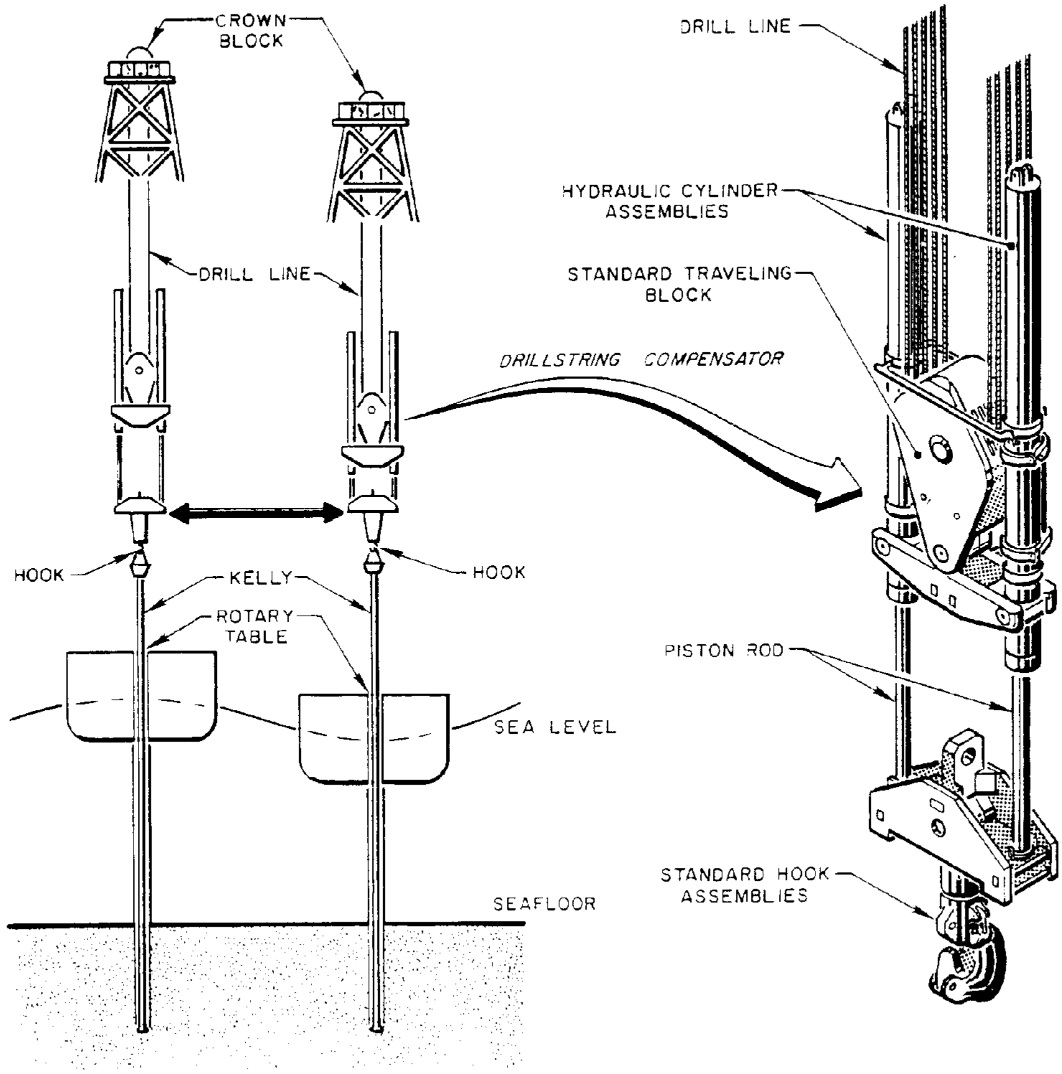

Figure 3-25: Drillstring Compensation System

Marine Riser and Guideline Tensioners: The functions of the marine riser are to provide a path for the returning drilling fluid, from the borehole to the surface and to guide the drillstring and other tools to the wellhead on the sea floor. Riser tensioners provide tension to the marine riser through a system of cables joined via sheaves to a series of pneumatic cylinders, as seen in Figure 3-26. Its purpose is to maintain the riser tension at all times regardless of rig heave. Common practice is to install four to six tensioners. Compensation for vertical movement several times the length of the stroke is possible due to multiple cable sheaves around the piston.

Guideline tensioners operate on the same principle as the riser tensioners. Their purpose is to maintain the correct tension in the guidelines between the rig and the guide-base (located on the sea floor), regardless of rig heave.

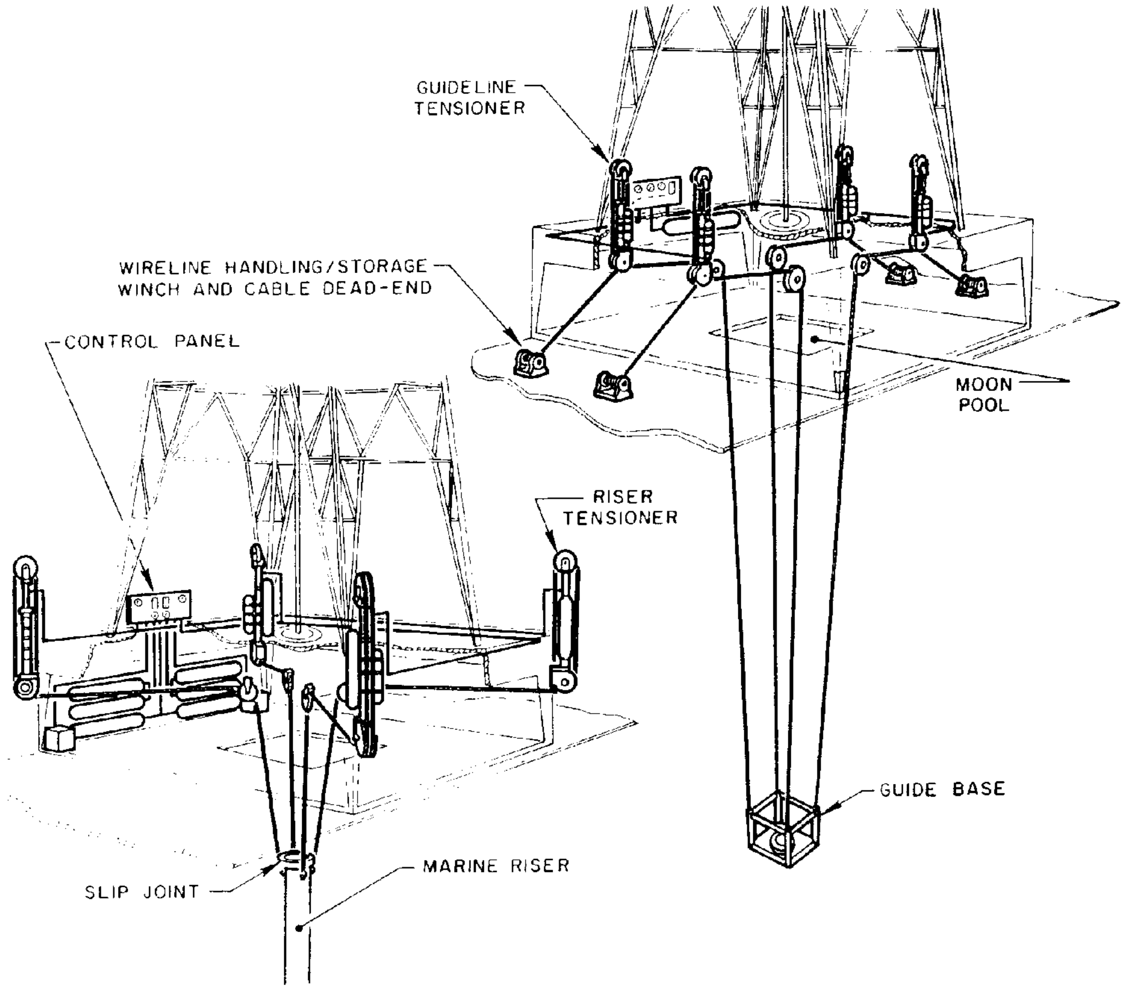

Figure 3-26: Riser and Guideline Tensioner Systems

Telescopic Joint: The telescopic joint is used at the top of the marine riser and is used to compensate for the vertical motion of the rig. It is comprised of an outer barrel and inner barrel. The outer barrel contains the packing elements which form the seal around the inner barrel. The inner barrel will have a stroke length from 45 feet to 55 feet and can be mechanically locked in the closed position for ease of handling on the rig.

Blowout Prevention (B.O.P.) System

Normally, the hydrostatic pressure of the drilling fluid column will be greater than the formation fluid pressures, preventing those formation fluids from entering the borehole. Should the hydrostatic pressure drop below the formation fluid pressure, formation fluids will enter the borehole. If this flow is minimal, causing a slight decrease in the drilling fluid density (mud density), the drilling fluid is said to be “gas cut”, “oil cut” or “saltwater cut”, depending on the fluid. When noticeable amounts of formation fluids enter the bore hole, the event is known as a “kick”. An uncontrolled flow of formation fluids is a “blowout”. As long as the hydrostatic pressure controls the well, circulation as indicated by the arrows in Figure 3-27, is normal, and the well may be left open.

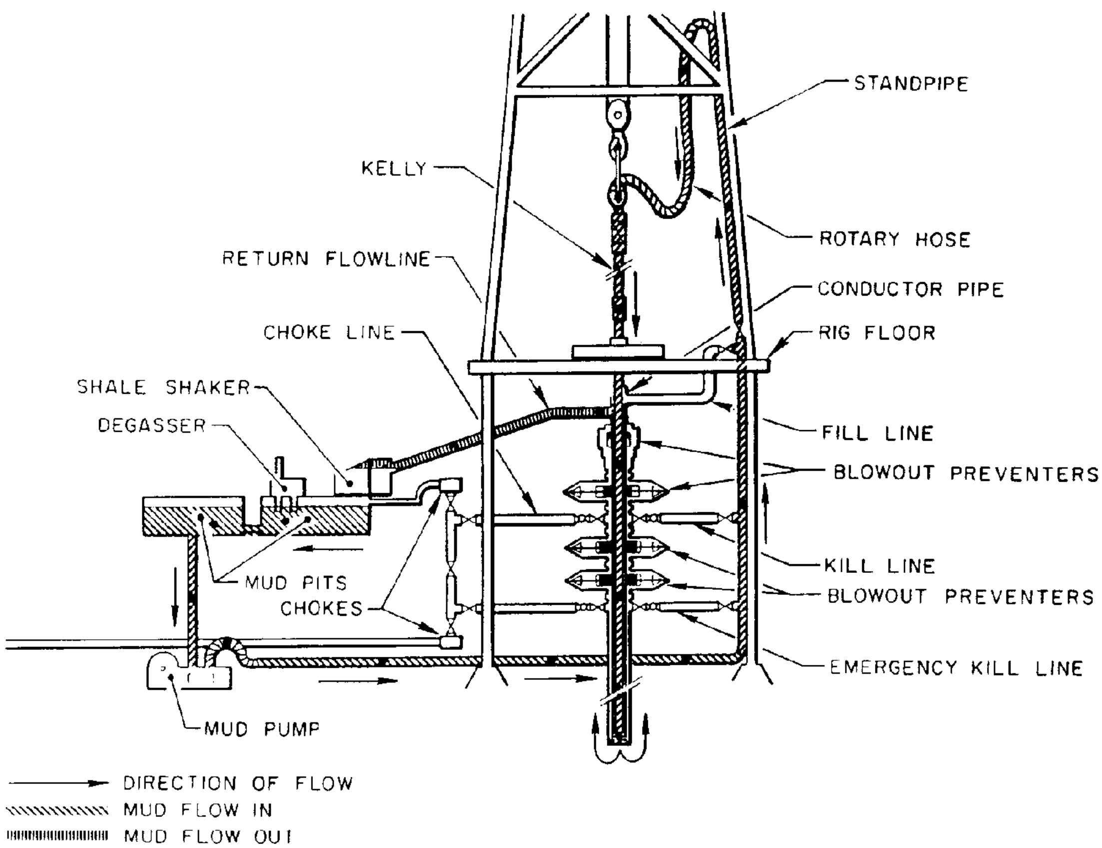

Figure 3-27: Schematic Projection Showing the Relationship Between the Circulation and BOP Systems

Should a kick occur, blowout prevention equipment and accessories are required to close (shut-in) the well. This may be done using an annular preventor (Figure 3-28), with pipe rams (Figure 29), or if the drillpipe is out of the hole, using the blind rams. In addition, it will be necessary to pump drilling fluid into the well and to allow the controlled escape of fluids. Injection of heavier drilling fluid is possible either through the drillpipe or through a kill line. Flow from the well is controlled using a variable orifice (choke). Choke lines will carry the fluid to a reserve pit where the undesired fluid is discarded or through a separator, where the fluid is degassed and saved.

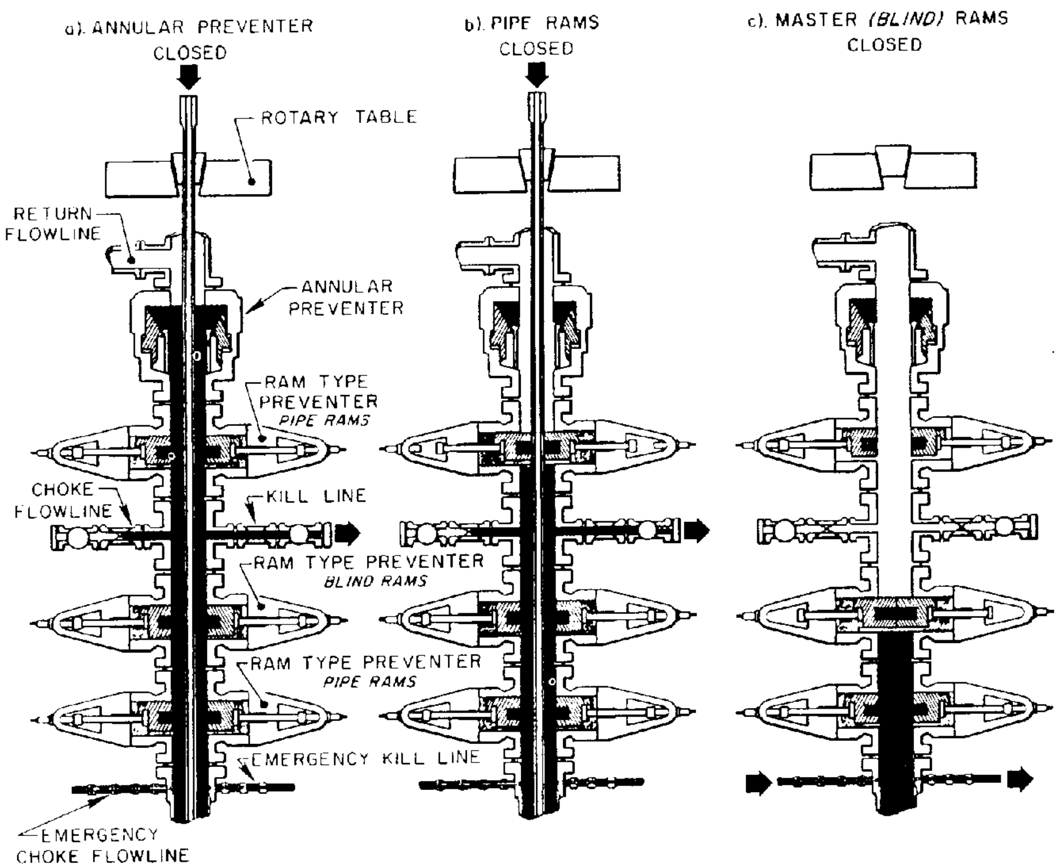

Figure 3-28: Blowout Preventor Stack in Various Operational Modes

As seen in Figure 3-28, the B.O.P. stack consists of a number of different blowout preventors. Their arrangement is decided by the degree of protection deemed necessary, and the size and type of drillpipe in the borehole. There are four types of blowout preventors:

- <u>Annular Preventor</u> (Figure 29): This consists of an annular rubber sealing element which, when pressure is applied, closes around the drillpipe or kelly. Since pressure can be applied progressively, the annular preventor can be made to close on any size or type of drillpipe. A slight relaxation of pressure may allow a small leakage of fluid and permit the pipe to be rotated within the annular preventor.

- Pipe Rams (Figure 29a): These have a rubber face molded to fit around a certain size of drillpipe. If more than one size drillpipe is in use, there must be one set of pipe rams for each size of pipe.
- Blind Rams (Figure 29b): These are hydraulic rams which will close and completely close off the borehole. As such, they are used only when there is no drillpipe in the borehole.
- Shear Rams (Figure 29c): These rams have specially designed cutting structures, which when closed on drillpipe, will cut through the drillpipe and completely close off the borehole.

The hydraulic pressure used to close the blowout preventors is supplied by “accumulators”, containing high pressure nitrogen. In an emergency, the ram preventors may be manually closed (but only on land rigs and jack-ups).

The B.O.P. stack also includes several other components necessary for controlling the well:

- Conductor Pipe: A length of casing attached to the top of the B.O.P. to extend the annulus to just below the rig floor. The top of this pipe is belled-out (nippled) to prevent tools from “hanging-up” when lowered through the rotary table. On one side of the conductor pipe is attached the drilling fluid return line (flowline), through which the drilling fluid is carried to the surface cleaning equipment.
- Choke Line: After the B.O.P is closed, high-pressure fluid can be released at carefully controlled rates by use of a hydraulically controlled valve. The choke line will carry the high pressure fluids away from the drilling rig.

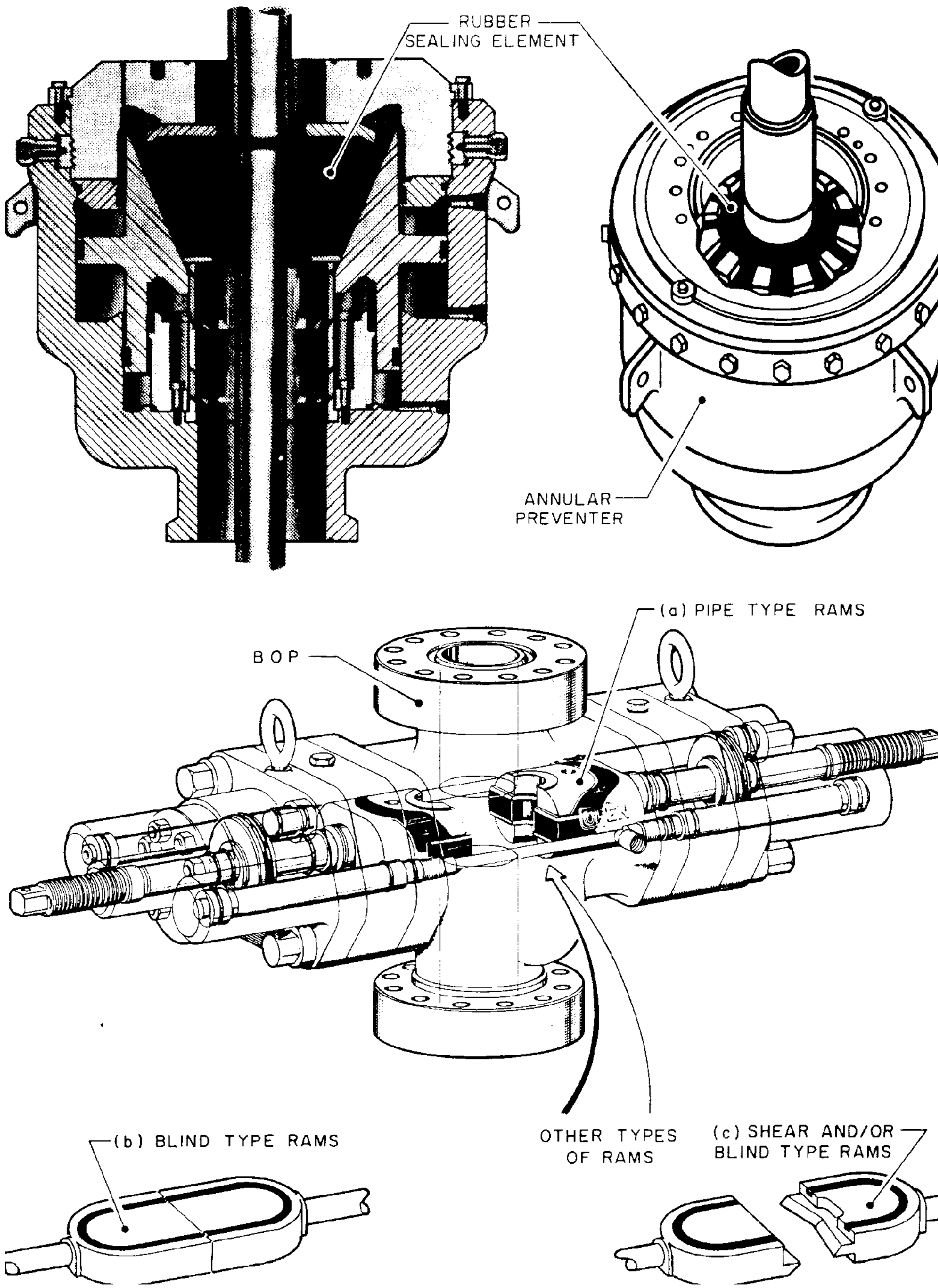

Figure 3-29: Blowout Preventors

- Kill Line: Heavy drilling fluid can be introduced through a check-valve in order to control high formation pressures. It fills the borehole from the top, instead of using the drillpipe to fill the borehole from the bottom. It is also used to fill the annulus when pipe is being tripped out.

The B.O.P. stack is not always situated directly under the rig-floor. On floating offshore rigs, the B.O.P. stack sits on the seabed. On jack-ups and platforms it rests on the “spider deck” below the rig floor, and on land rigs, it is located in a dug out chamber under the rig floor, called the “cellar”. This is illustrated in Figure 3-30.

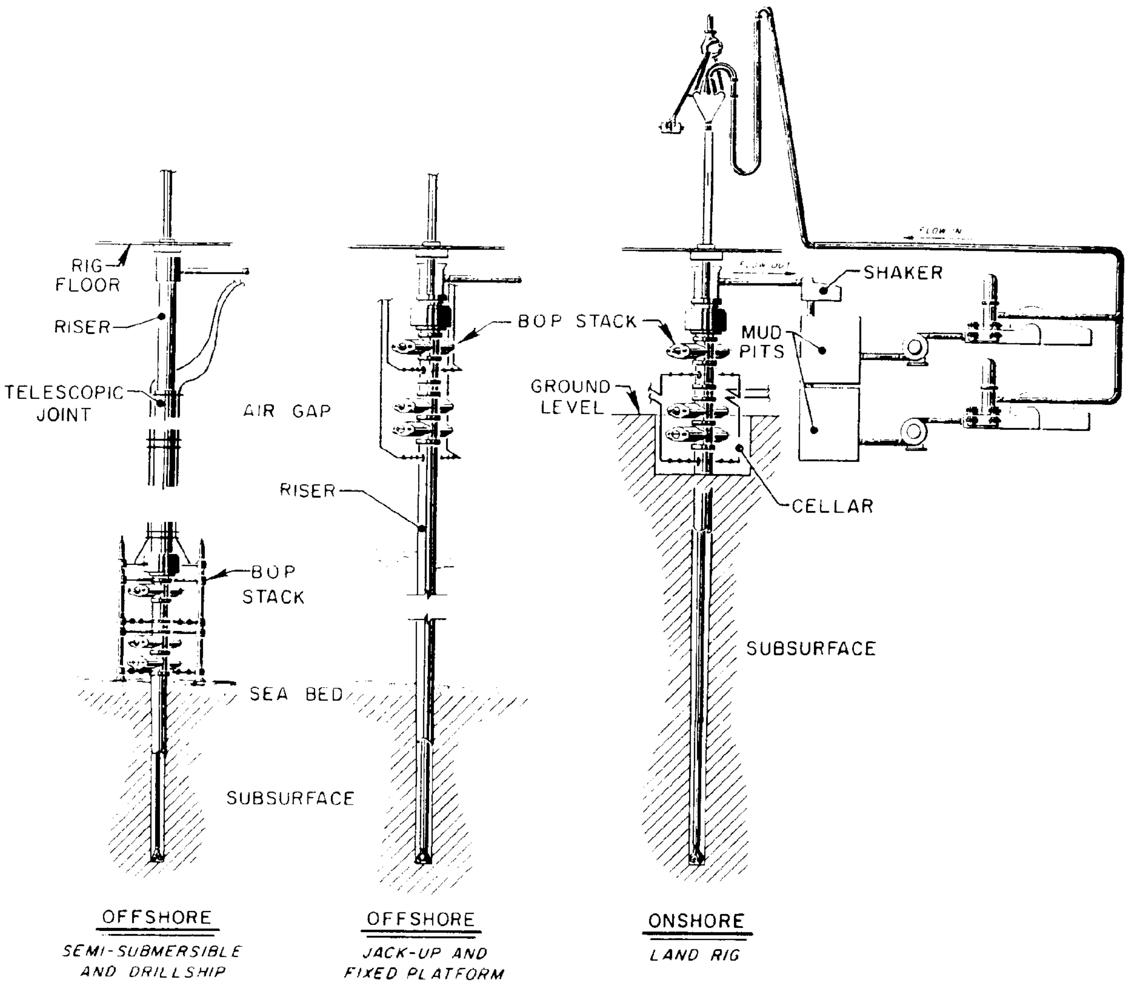

Figure 3-30: BOP Stack Positions Governed by Rig Type

Drilling And Completing A Well

The drilling contractor is employed by the oil company to routinely drill ahead (make hole). However, a number of related services must be performed in order to properly drill the borehole and complete the well, whether it is a dry hole or a producer.

After the well is spudded, routine drilling consists of continuously drilling increments of drillpipe, making connections (adding to the drillstring of another joint or stand of drillpipe), and continuing until it is time to change the drill bit. The bit must be changed when it is worn or when a formation is encountered for which the particular bit being used is not suitable. Changing the bit is accomplished in an operation called “tripping”. A round-trip includes coming out of the hole, changing the bit, and going back into the hole.

Connections

When the kelly, or top-drive system, has drilled all the way down, it is withdrawn and a new length of drillpipe is added. Refer to Figure 4-1 (a through d) for the following text description.

In (a) the kelly is near the “kelly down” position, where another joint of pipe must be added. The new length of pipe has been placed in the “mousehole”, ready to be connected. The mousehole is used to store the next measured joint of pipe until it is required for threading into the drillstring. The crew breaks-out the kelly so that it can be swung over to the joint of pipe in the mousehole, as in (b). The kelly is made-up on the joint and tightened with the tongs. In (c) and (d), the new joint of pipe is picked up, swung over to the pipe hanging in the rotary table, and “stabbed” into the drillstring. The new pipe is screwed into the drillstring, tightened with the tongs, and lowered into the borehole to drill another joint length.

The difference with “top drive” systems is that the kelly is not used and stands of pipe are drilled instead of joints. The next stands to be drilled may be placed in the mousehole or may be left standing in the monkey-boards.

Trips

When making a trip, drillpipe is handled in stands of three joints each (approximately 93 feet). Pipe is removed from the borehole and set back on the rig floor. Refer to Figure 4-2 for the procedure for pulling pipe out of the hole (tripping out). The kelly, rotary bushing and swivel are placed in the rathole during the trip, as seen in (a). With the kelly out of the way, the elevators are latched around the pipe just below the tool joint's box end.

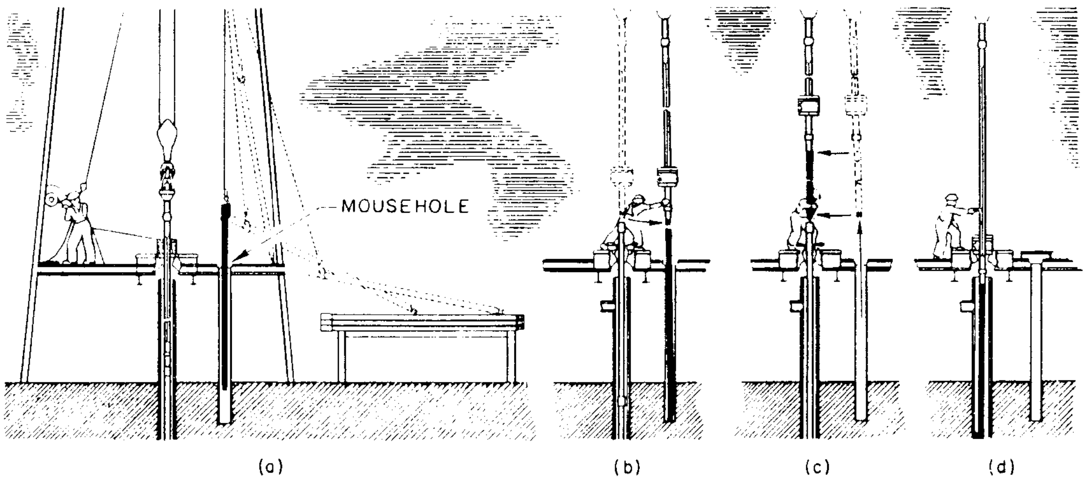

Figure 4-1: Making a Connection

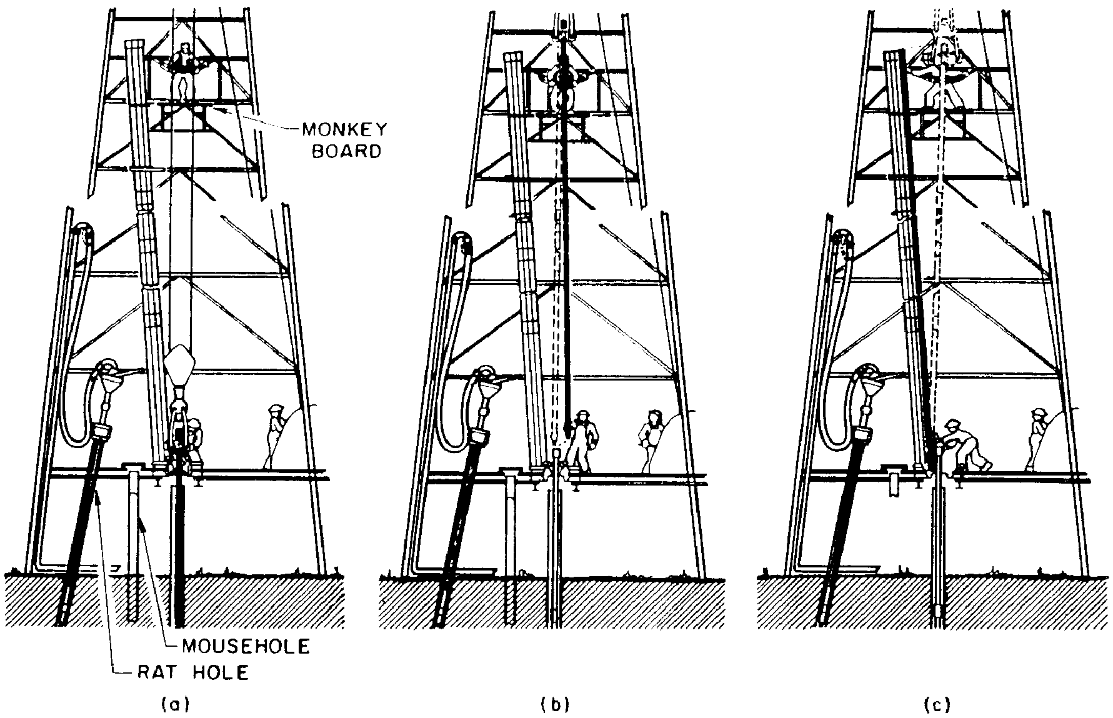

Figure 4-2: Tripping Out of the Borehole

The tool joint's box end provides a shoulder for the elevators to pull against. The pipe is then pulled from the borehole, and after being secured in the rotary table (using the slips), the connection is loosened with the break-out tongs. A spinning wrench (power tongs) are commonly used to unscrew the pipe at this time. This is illustrated in Figure 4-3.

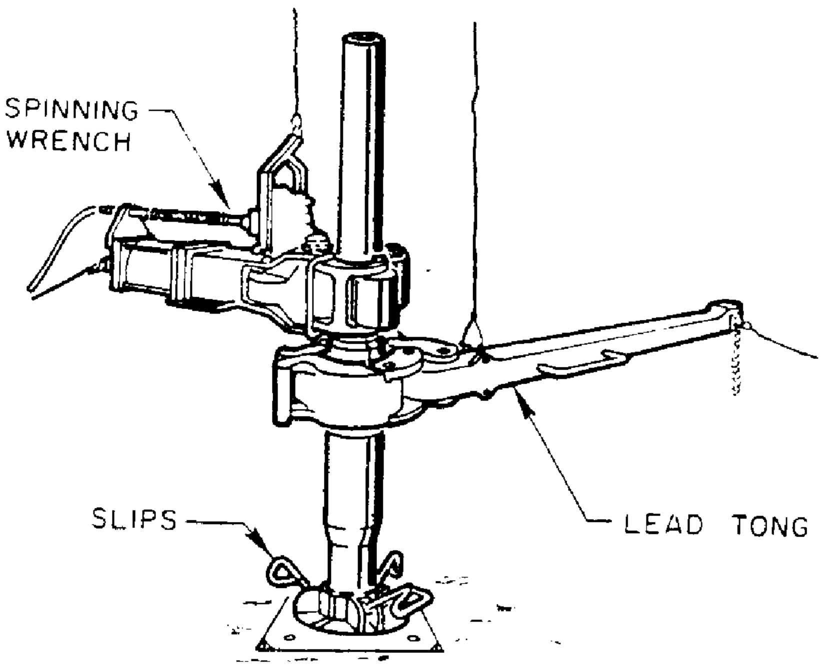

Figure 4-3: Separating a Connection

The top of the stand, which has been pulled past the derrickman (standing on the monkey-board, Figure 4-2b), has a rope thrown around it. The bottom of the stand is swung to one side of the drill floor where it is set down (Figure 4-2c), and the derrickman racks the top of the stand in the “fingers” in the monkey board to secure it.

The drill collars and bit are the last to come out of the borehole. The master bushing may have to be removed to allow the large diameter collars to pass through the rotary table. When the bit appears, the master bushing is replaced and a “bit breaker” is placed in the rotary table. Using the break-out tongs, the bit is loosened and removed from the bit sub.

Tripping in, is just the reverse procedure of tripping out.

Some rigs have a pipe handling system to speed up pipe movement during tripping operations (Figure 4-4)

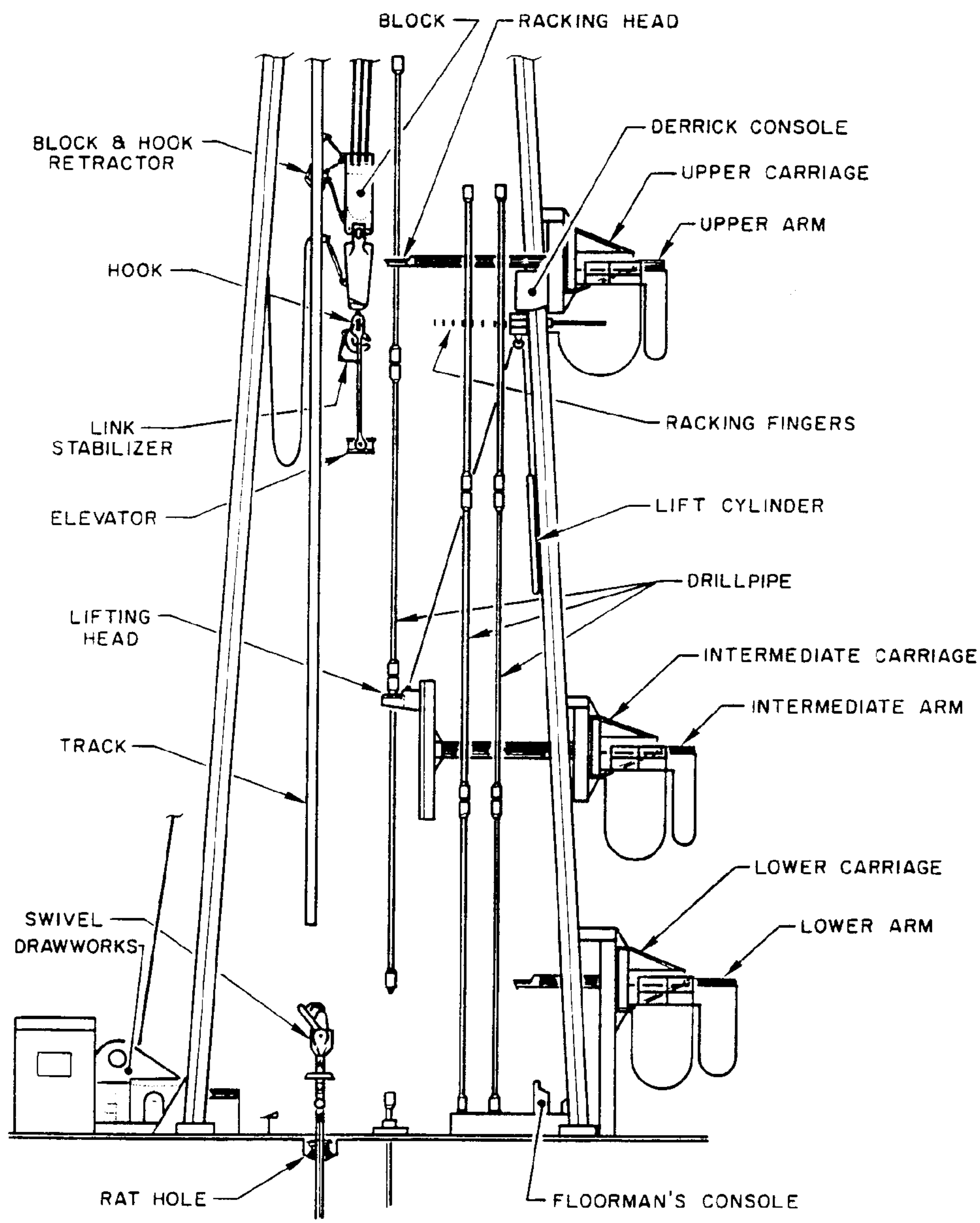

Figure 4-4: Pipe Handling System

Related Services

Specialized services are usually required at the wellsite. These are provided by companies whose contracts are separate from the drilling contractor. Some of the services are shown in the following diagram (Figure 4-5).

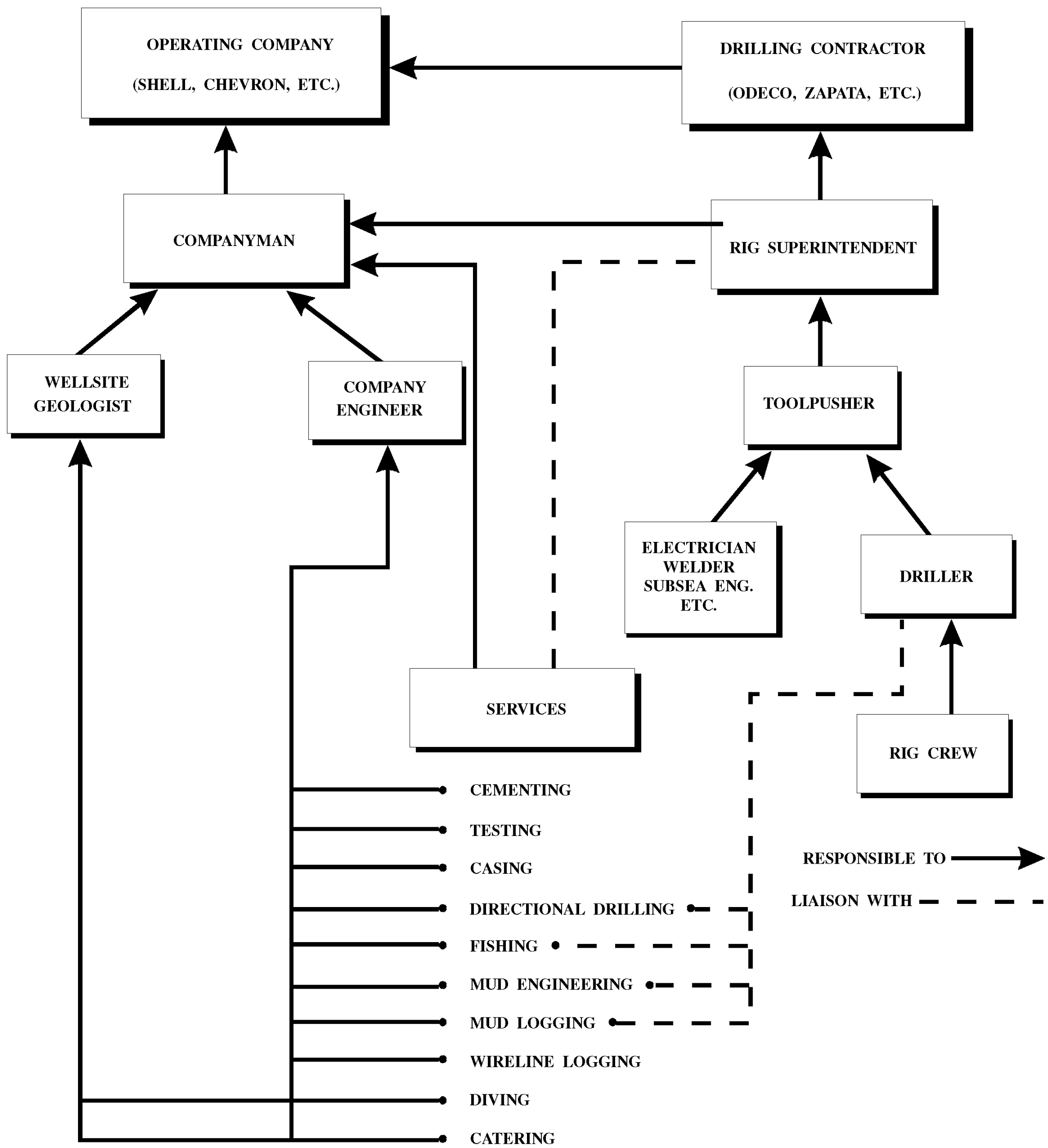

Figure 4-5: Interrelationships of Operator, Drilling Contractor and Service Companies

These services are coordinated by the operating company (the oil company). The interrelationships of the client, drilling contractor and service companies is illustrated in Figure 4-5. The mud logging, MWD, wireline logging and formation testing service companies are known in the industry as the "formation evaluation" companies.

Drilling Fluids Engineering

Initially, the primary purpose of drilling fluids was to clean, cool and lubricate the bit and continuously remove cuttings from the borehole. But with progress came sophistication, and more was expected from the drilling fluid (mud). Many additives for any conceivable purpose were introduced, so what started out as a simple fluid has become a complicated mixture of liquids, solids and chemicals for which "mud engineers" are contracted by the operating company to maintain. Today, the drilling fluid must permit the securing of all information necessary for evaluating the productive possibilities of the formations penetrated. The fluids' characteristics must be such that good cores, wireline logs and drill returns logs can be obtained. Drilling fluid is discussed here from the standpoint of:

- Technology
- Chemistry
- Mud Conditioning Equipment

Drilling Fluid Technology

Numerous types of mud are available due to the varied hole conditions. Factors such as depth, types of formations, local structural conditions, etc., all enter into the choice of a particular mud. The functions and corresponding properties of a drilling mud are to:

- Control subsurface pressures and prevent caving (mud density)
- Remove cuttings from the borehole (viscosity)
- Suspend cuttings when circulation stops (gel strength)
- Cool and lubricate the bit and drillstring (additive content)
- Wall the borehole with an impermeable filter cake (water loss)
- Release the cuttings at the surface (viscosity/gel strength)
- Help support the weight of the drillstring/casing (density)
- Ensure maximum information from the formation
- Do all of the above, without damage to the circulation system

Controlling Subsurface Pressures: The pressure of the mud column at the bottom of the borehole is a function of the mud density and column height. This pressure must be adequate at all times to prevent the flow of formation fluids into the borehole. Should mud density fall below that which is necessary to hold back formation pressures, then formation fluids can enter the well. This is termed a “kick”. If this condition is allowed to continue unchecked for even a short period of time, the mud density may be reduced (cut) so severely that uncontrolled flow will result. This is termed a “blowout”.

On the other hand, it is not practical or economical to have the mud weight too high. Excessive mud weights result in low rates of penetration and in the fracturing of weak formations, and may cause the loss of drilling mud into them (lost circulation).

Density is also important in preventing unconsolidated formations from caving into the borehole.

The effect of mud weight on drill returns logging:

- Hydrostatic pressure in excess of formation pressure will cause formation fluids to be flushed back into the formation being penetrated, either at the bit or just ahead of it. This flushing occurs at all times, whether marginally or greatly overbalanced. If circulation is lost, then the cuttings, drilling mud and any formation fluids they may contain are also lost.

  The way in which a lost circulation zone behaves generally indicates the type of porosity of the formation into which the fluid is being lost. Examples are:

  a) Coarse, permeable unconsolidated formations: There is normally some loss by filtration into these formations, until an impermeable filter cake if formed. If pore openings are large enough, then loss of whole mud occurs. Other than in extreme cases, this is a slow, regular seepage loss. Partial returns are maintained.

  b) Cavernous and vugular formations: Loss is usually sudden and of a finite amount, after which full returns are maintained.

  c) Fissured or fractured formations: Fractures may be natural or induced and opened by the hydrostatic pressure. Losses of drilling mud are large and continuous.

- Formation pressures that approximate or are greater than the hydrostatic pressure may allow entry of formation fluids, depending on permeability. In low permeability formations (shales), cavings may occur, making cuttings analysis difficult.

The following term must be understood when discussing pressure-control terminology.

- Hydrostatic Pressure

  This is the pressure which exists due to the drilling fluid weight and vertical depth of the column of fluid.

$$Hp = C \times MD \times TVD$$

where: C = Conversion constant
MD = Mud Density
TVD = True Vertical Depth

If:		
	Hp = psi	Hp = bars
	MD = lbs/gal or ppg	MD = g/cc
	TVD = feet	TVD = meters
	C = 0.0519	C = 0.0981

Removing and Suspending the Cuttings: The drilling mud must carry the cuttings up the borehole and suspend them when circulation is stopped. The most important factors involved are the speed at which the mud travels up the borehole (annular velocity), and the viscosity and gel strength of the drilling mud.

1. Viscosity

   Applied to drilling fluids, viscosity may be regarded as the resistance that the drilling fluid offers to flow when pumped. The viscosity affects the ability of the drilling fluid to lift the rock cuttings out of the borehole. The viscosity is dependent on the amount and character of the suspended solids. Viscosity is ordinarily measured in the field using a “Marsh Funnel”. The funnel is filled with one quart of drilling fluid, and the elapsed time to empty the funnel is recorded in seconds. The measurement of “funnel viscosity” is “sec/qt” (seconds per quart). This value can range from 20 to 80, but is normally maintained between 40 and 50.

4. Gel Strength

   Gel strength refers to the ability of the drilling fluid to develop a gel as soon as it stops moving. Its purpose is to suspend the cuttings and mud solids (weight material), while they are in the borehole and not permit them to settle around the bit when circulation is halted. In general, gel strength should be low enough to:

   - Allow the cuttings to be removed at the surface
   - Permit entrained gas to be removed at the surface

- Minimize swabbing when the pipe is pulled from the borehole
- Permit starting of circulation without high pump pressures

The gel strength is most commonly determined with a “Fann VG (Viscosity/Gel) Meter” and is expressed in lbs/100ft^2 (pounds per 100 square feet). Drilling muds ordinarily have gel strengths between 5 and 30 lbs/100ft^2.

The effect of viscosity and gel strength on drill returns logging:

- If the viscosity or gel strength (or both) is too high, the drilling fluid tends to retain any entrained gas as it passes through the surface mud cleaning equipment, with the effect that the gas may be recycled several times. Swabbing of the borehole may also introduce extraneous gas anomalies.
- Fine cuttings may be held in suspension so they cannot be removed at the shale shakers and settling pits, thus recycling and contaminating the cuttings samples. Also, cuttings consisting of clays or other dispersible material may be dissolved.

Cooling and Lubricating the Bit and Drillstring: Practically any fluid that can be circulated through the drillstring will serve to cool the bit and drillstring. Lubrication, however, commonly requires special mud characteristics that are gained by adding oil, chemicals and other materials.

Walling the Borehole with an Impermeable Filter Cake: The hydrostatic pressure of the column of drilling fluid exerted against the walls of the borehole helps prevent the caving of unconsolidated formations. A plastering effect, or the ability to line permeable portions of the borehole with a thin, tough filter cake, is also produced.

Control of the filtration rate (water loss) is necessary for two reasons:

1. A poor quality filter cake may cause excessive water loss and produce an excessively thick filter cake, thereby reducing the diameter of the borehole which increases the possibility of sticking the drillstring and the swabbing effect when pulling the drillpipe.
2. High water loss can cause deep invasion of the formations, making it difficult to interpret wireline logs.

Drilling Fluid Chemistry

Drilling fluids are intended to fulfill the functions described above. While the list of chemical additives used to develop these functions is extensive, there are only three basic drilling fluid types:

- Water/clay muds

- Oil/water clay muds
- Compressed gases

Water/Clay Muds: This is the major type of mud system. It consists of a continuous liquid phase of water in which clay materials are suspended. A number of reactive and nonreactive solids are added to obtain special properties. A water-based mud system is a three-component system consisting of water, and reactive and inert solids.

1. Water

   This may be fresh water or salt water. Seawater is commonly used in offshore drilling and saturated saltwater may be used for drilling thick evaporite sequences to prevent them from dissolving and causing washouts. Saturated saltwater is also used for shale inhibition.

2. Reactive Solids

   Clays: this basic material of mud is commonly referred to as "gel". It affects the viscosity, gel strength and water loss. Common clays are:

   - Bentonite - for fresh water muds
   - Attapulgite - for saltwater muds
   - Natural formation clays which hydrate and enter the mud system

   Dispersants: they reduce viscosity by adsorption onto clay particles, reducing the attraction between particles. Examples are tannins, quebracho, phosphates, lignite and lignosulphonates.

   Filtration Control Agents: they control the amount of water loss into permeable formations, due to the pressure differential, by ensuring the development of a firm impermeable filter cake. Some are:

   - starch - pregelatinized to prevent fermentation
   - sodium carboxy-methyl cellulose (CMC) - organic colloid, long chain molecules which can be polymerized into different lengths or "grades". The grades depend on the desired viscosity.
   - polymers - for example cypan, drispac, used under special conditions

   Detergents, Emulsifiers and Lubricants: to assist in cooling and lubricating. Also used for a spotting fluid in order to free stuck pipe.

Defoamers: these prevent mud foaming at the surface in treatment equipment.

Sodium Compounds: precipitate or suppress calcium or magnesium which decreases the yield of the clays.

Calcium Compounds: they inhibit formation clays and prevent them from hydrating or swelling.

3. Inert Solids

Weight Material: these are finely ground, high-density minerals held in suspension to control mud density. Common weight materials are barite, hematite and galena.

Lost Circulation Material (L.C.M.): this is added to the mud system in order to bridge-over or plug the point of loss. It is available in many sizes and types to suit particular circulation loss:

- Fibrous: wood fiber, leather fiber
- Granular: walnut shells (nut plug), fine, medium, coarse
- Flakes: cellophane, mica (fine, coarse)
- Reinforcing Plugs: bentonite with diesel oil, time setting clays, attapulgite and granular (squeeze)

If none of these materials successfully plug the lost circulation zone, the zone must be cemented off.

Anti-friction material: this is added to the mud system to reduce torque and decrease the possibility of differential sticking. The most frequently used material is inert polyurethane spheres. More frequently it is used on high angle directional wells, where torque and differential sticking are a problem.

Oil/Water/Clay Muds: Two basic types of oil/water mud systems are used:

1. Emulsion (oil/water) System, in which diesel or crude oil is dispersed in a continuous phase of water.
2. Invert Emulsion (water/oil) System, in which water is dispersed in a continuous phase of diesel/crude oil.

These mud systems have desirable properties as completion fluids or when drilling production wells. They are nonreactive with clays and their filtrate will not damage the formations. Their high cost and difficulty of running, and complication of geological evaluation preclude their use on exploratory wells, other than in certain troublesome evaporite and clay sections. Apart from these emulsions containing roughly equal portions of oil and water, there are true oil-based muds which may contain only 5 percent water.

When oil-based mud systems are in use, special considerations must be made regarding formation evaluation.

Compressed Gases: Compressed air or natural gas is occasionally used as a drilling fluid (at times with a foaming agent to improve carrying capacity), but its use is applicable only in areas where there is little formation water. The compressed air or gas is circulated the same as conventional drilling mud, except compressors are used instead of mud pumps.

Drilling Fluid Conditioning Equipment

Drilling fluid returning from the borehole contains drilled cuttings, mud solids, other particles, and sometimes hydrocarbons - all of which must be removed before the mud is suitable for recirculating in the well. Also, treatment chemicals and clays must be added to the mud system from time to time to maintain the required properties. The equipment necessary to perform these functions is presented and listed in Figure 4-6.

Shale Shaker: Fluid returning from the borehole immediately passes over the shale shaker, which contains sloping, vibrating screens. The mesh size is small enough to allow the mud to fall through, returning it to large mud tanks (pits). The cutting samples, however, travel to the bottom edge of the screen where they are dumped. It is at this point they are collected for geological examination.

Settling Pit (Sand Trap): The first pit to receive the drilling fluid after it leaves the shale shaker is the sand trap. The bottom of this pit is usually sloped so that particles that passed through the shaker screens will segregate out, by gravity, and settle towards clean-out valves. These valves are opened periodically so that the solids can be dumped.

Desander, Desilter and Centrifuge: The desander and desilter separate solids in a hydroclone, in which the fluid rotates and the solid content is caused to separate by centrifugal force, as illustrated in Figure 4-7.

A hydroclone imparts a whirling motion to the fluid, thereby achieving sufficient centrifugal force to separate various particle sizes. A pump is used to feed the drilling mud through a tangential opening into the large end of the cone-shaped housing. A hydroclone operates in a similar manner, whether used as a desander, desilter or for the recovery of weighting materials. When being used as a desander or desilter, the underflow from the apex contains the coarse solids (which are discarded) while the overflow from the apex is returned to the active mud system. Conversely, when the hydroclone is used on weighted muds, the underflow contains the barite which is saved and returned to the active mud system, while the effluent contains the clays and colloidal particles to be discarded. Hydroclones are often used on low-weight, water-based muds to remove coarse drilled solids. Individual cones are manifolded in parallel to provide any desirable throughput, and are sized to fit the capacity of the pump provided for circulation through the cone units.

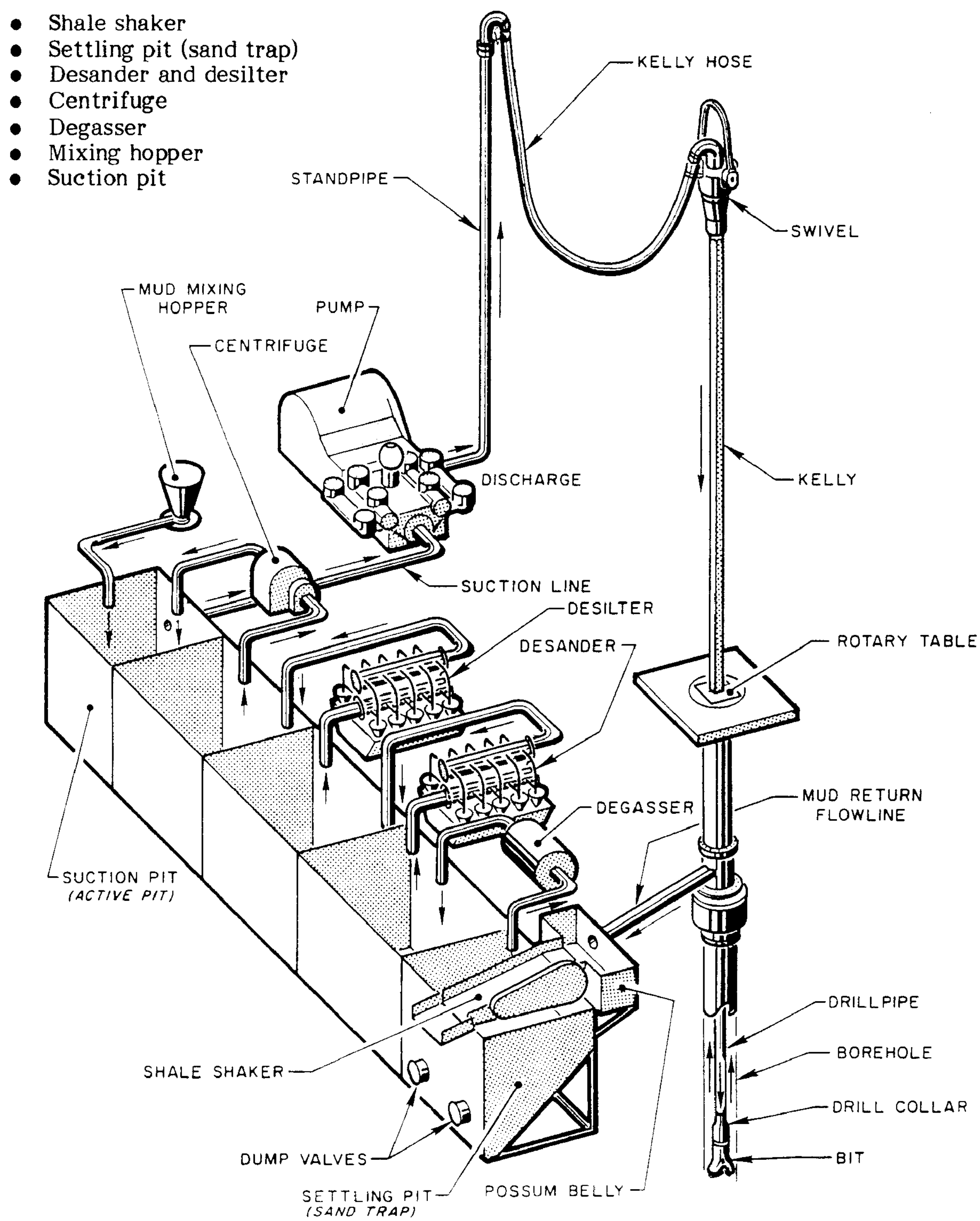

Figure 4-6: Mud Conditioning Equipment

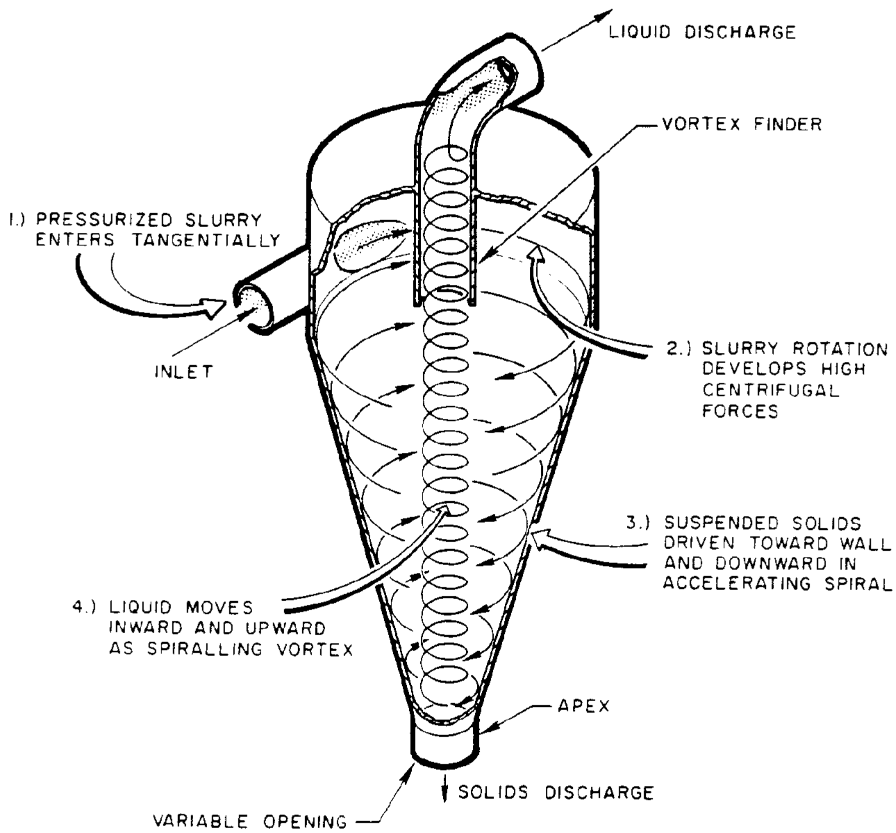

Figure 4-7: Hydroclone

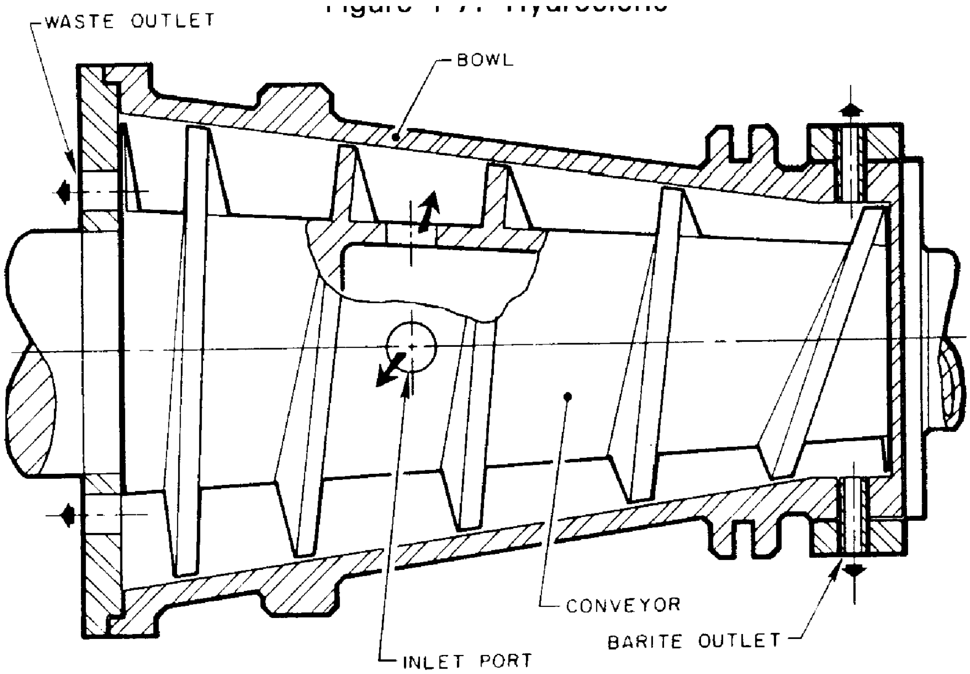

Figure 4-8: Centrifuge

The centrifuge (Figure 4-8) like the barite salvage hydroclone, is used for salvaging materials that are to be retained in the mud system. The centrifuge, however, is much more efficient. It consists of a rotating cone-shaped drum (or bowl) that turns at a high rate of speed and a conveyor screw within the drum that moves the coarse particles to the discharge port and back to the active system.

Degasser: Recirculation of gas-cut mud may be hazardous and can result in reduced pumping efficiency, and less hydrostatic pressure to contain formation pressures. The usual practices of running the returning mud across a shale shaker, using settling action in the pits and stirring the mud in the hydroclones may not completely release the entrained gas from the mud. In this case, it may be necessary to pass the mud through a degasser. Two general types of degassers are commonly employed:

- Mud-Gas Separators
- Vacuum Degassers

A mud-gas separator is desirable to safely handle high-pressure gas and mud flows from a well when a “kick” takes place. The vacuum degasser is more appropriate for separating entrained gas, which resembles foam on the surface of the mud.

1. Mud-Gas Separators

   Various types of mud-gas separators are used. Most, however, consist of a vertical vessel arranged to vent free gas from the upper end and discharge relatively gas-free mud from the bottom. To operate a mud-gas separator, the borehole must be shut-in and mud circulated through the choke manifold. Well flow is diverted from the flow line or choke manifold to the mud-gas separator. The separator releases the gas which is then carried by the vent line at the top to a remote flare.

2. Vacuum Degasser

   This type of degasser (Figure 4-9) is mounted over a mud tank from which it takes suction. The mud enters near the top of a horizontal barrel and flows along a section of large pipe that is closed at its far end. The top of the pipe is sliced away in a horizontal plane so that the mud can spill over the sides and down an inclined plane extending the full length of the feed pipe and sloping downwards. As the mud streams down the inclined plane, a vacuum in the vapor space causes the gases to release from the mud and be withdrawn from the tank by a vacuum pump. The degassed mud, back to its normal weight, flows to the bottom of the barrel for exit.

Mixing Hopper: The most common hopper in use is the "jet hopper" (Figure 4-10). It was originally developed for mixing cement and water slurry for oil well cementing. It is now used for adding material to the mud system to achieve the desired physical and chemical properties. In operation, a mixing pump or centrifugal pump circulates mud from the mud pit through the jet hopper and back to the mud pit.

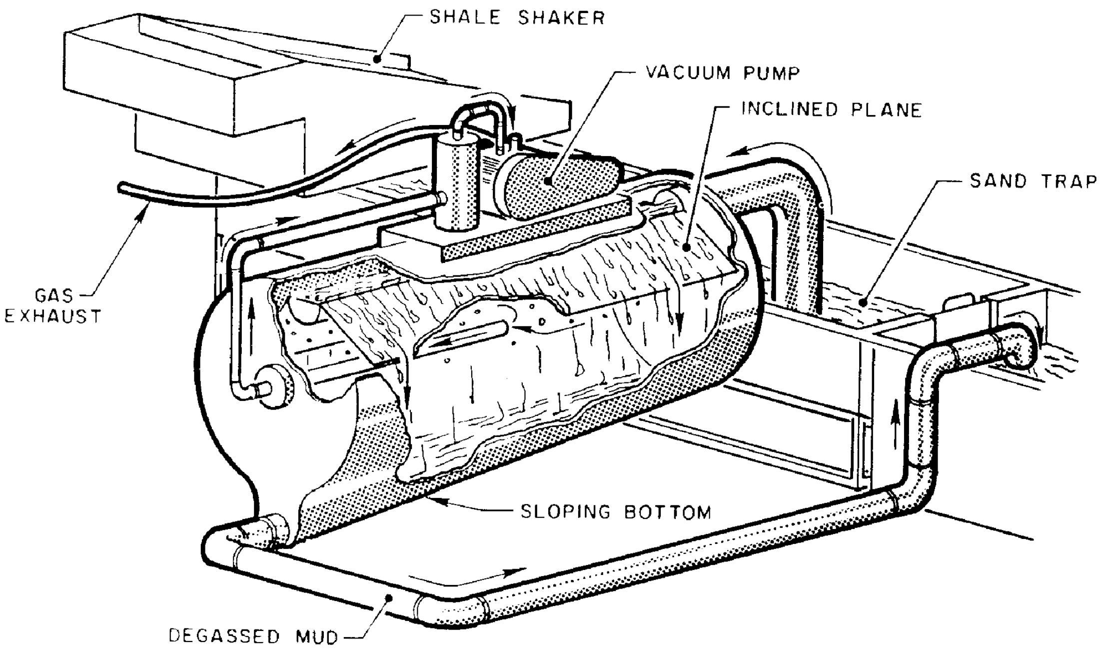

Figure 4-9: Vacuum Degasser

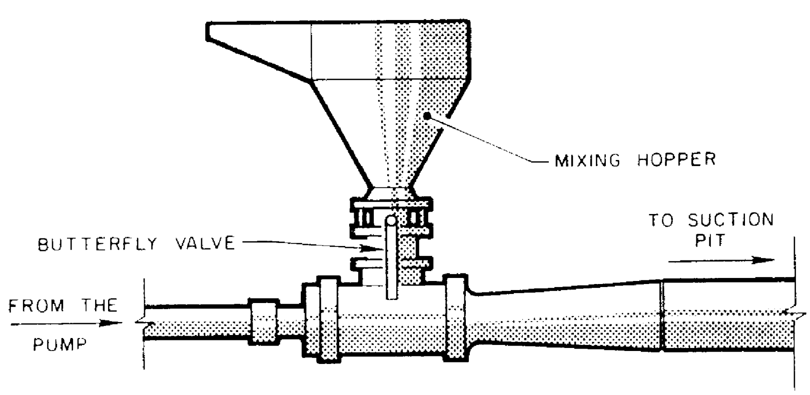

Figure 4-10: Jet Hopper for Mixing Mud

The fluid velocity, through the jet nozzle in the hopper, lowers the static pressure in the housing to below atmospheric. A vacuum is created and material placed in the hopper is sucked into the stream of fluid where it becomes mixed with the fluid. Powered mud materials, such as bentonite, barite, chemicals, as well as solids such as cellophane and nut hulls, can be added to the mud through a jet hopper.

Suction Pit: Drilling fluid is stored and mixed in this very large pit before returning to the mud pumps to be recirculated through the borehole.

Casing and Cementing

Drilling a hole to a gas or oil reservoir requires two operations. One is to drill the borehole, and the second is to periodically line the borehole with steel pipe (casing). Once installed, this casing is cemented into place to provide additional support and a pressure-tight seal.

Casing

Casing in a well serves a number of functions, it:

- Prevents caving of the borehole
- Provides a means of containing well (formation) pressures by preventing fracturing of upper, weaker zones
- Provides a means for attaching surface equipment (blowout preventors and production tree)
- Confines production to the wellbore
- Allows segregation of formations behind the pipe and thereby prevents inter-formational flow, and permits production from a specific zone
- Permits installation of artificial lift equipment for producing the well
- Provides a borehole of a known diameter for further operations

One or more of the following strings of casing is required in every well:

  - Conductor Pipe
  - Surface Casing
  - Intermediate Casing
  - Liner String
  - Production Casing (tubing)

These are illustrated in Figure 4-11. Casing size is defined by its outside diameter (O.D.) in inches, and its weight per foot (lb/ft).

Conductor Pipe: This is needed as a conduit to raise the circulating fluid high enough to return the fluid to the surface pits. It also prevents washing out from around the base of the rig. Holes for the conductor pipe can be drilled in the usual fashion, but the pipe is often driven in with a pile driver (especially in swamps and offshore locations on jack-ups and fixed platforms). Conductor Pipe usually ranges from 30 to 42 inches in outside diameter offshore, and 16 inches onshore.

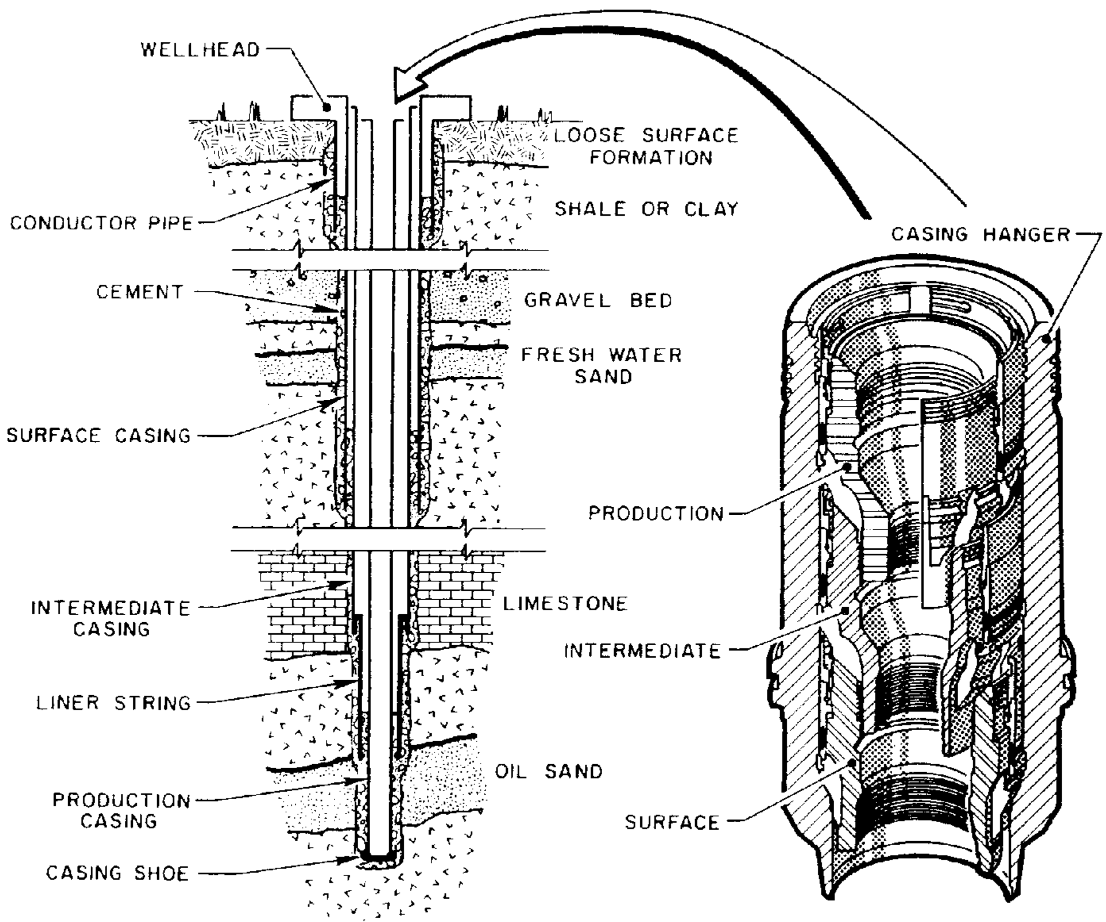

Figure 4-11: Casing Strings and Hanger

Surface Casing: This is set deep enough to protect the well from cave-in of loose formations that are encountered near the surface and to isolate the fresh water formations. It is the starting point for the wellhead, and in most cases serves as the base for the B.O.P stack during drilling operations and the “Christmas Tree” if the well is completed for production. An important factor concerning the setting depth of surface casing, is that the string should be deep enough to reach formations that will not break down with the maximum expected mud density at the depth where the next string will be set. All later strings are suspended and sealed at the top of the surface casing by means of a casing hanger.

Intermediate Casing: The primary purpose of an intermediate casing string is to protect the borehole. Usual functions of this string of casing is to protect against lost circulation in upper zones and high-pressure zones deeper in the well. In general, intermediate casing is set to seal off or protect some problem area, and provide safety for further drilling.

Liner String: Unlike casing, which is run from the surface to a given depth and overlaps the previous casing, a liner is run only from the bottom of the previous string to the bottom of the borehole. There is a minimal overlap with the previous casing, and the liner is suspended in this overlap by means of a liner-hanger. They are often cemented in place, but some production liners are suspended from the previous string. Any type of casing can be used as a liner.

Production Casing (Tubing): This serves to isolate the hydrocarbons during production from undesirable fluids in the producing formation and from other zones penetrated by the wellbore. It is the protective housing for the pumps and other production equipment.

Running Casing

Prior to running casing, the hole will be cleaned (removing the cuttings and filter cake) by doing one or more “short trips”. Once cleaned, a contract company will run wireline logs. During wireline logging, the drill crew will prepare the rig for the casing run.

Once logging is over, the drillpipe elevator is removed and a heavy duty “slip” elevator is installed to fit the casing. A “casing slip” is also installed over the rotary table. A board is rigged up in the derrick (a “stabbing board”), so that the derrickman can stand and handle the individual joints of casing and guide the elevators into position on the pipe. A pick-up line attached to the hook, raises the individual casing joints into the derrick, then the joint is stabbed (connected to another). The casing elevator is not latched to the full string of casing until the joint is made up. Following this, the casing string is lowered through the rotary table and wedged with the casing slips, ready to receive the next length of casing. Power tongs are used to ensure proper make-up of each threaded joint. There is an arrangement for intermittently filling the casing with mud as the string is run into the borehole. This prevents collapse due to insufficient hydrostatic pressure inside the casing.

Casing Accessories

The accessories described below are illustrated in Figure 4-12.

- Guide Shoes: As the name suggests, a guide shoe is attached to the first length of casing to be lowered into the hole. It is aluminum with a hole in the center and rounded, to guide the casing into the borehole, around obstructions.
- Float Collars: These devices permit the casing to literally float into the borehole, by virtue of being partially empty. It is a back pressure valve which is closed by the outside fluid column, thereby preventing entry of the fluid as the casing is lowered into the hole. It also serves as a check-valve in the casing string, to prevent back flow of cement after being pumped outside the string. This is important because the density of the cement slurry is always greater than drilling mud. This back pressure valve serves to prevent a blowout through the casing, if a kick should occur during casing operations.

  A float collar also serves as a “stop” for the two plugs when cement is displaced. This action allows a quantity of slurry to stay inside the casing at the casing shoe, so that the operator has reasonable assurance of there being adequate cement outside the casing at that point.
- Centralizers and Wall Scratchers: These are attached to the casing for two main reasons:
  1. To ensure a reasonably uniform distribution of cement around the pipe
  2. To obtain a competent seal all the way around the casing and with the adjoining formation

  Centralizers hold the casing away from the borehole wall and therefore also serve to prevent differential sticking. Wall scratchers are mechanical wall cleaning devices, attached to the casing, that abrade the hole when worked by reciprocating or rotating. This helps to provide a more suitable surface for the cement to bond to.
- Cementing Head: This provides the union for connecting the cementing lines from the cementing pump to the casing. This type of head makes it possible to circulate the mud in a normal manner, release the bottom plug, mix and pump the cement and pump it down, release the top plug, and displace the cement without making or breaking any connections.

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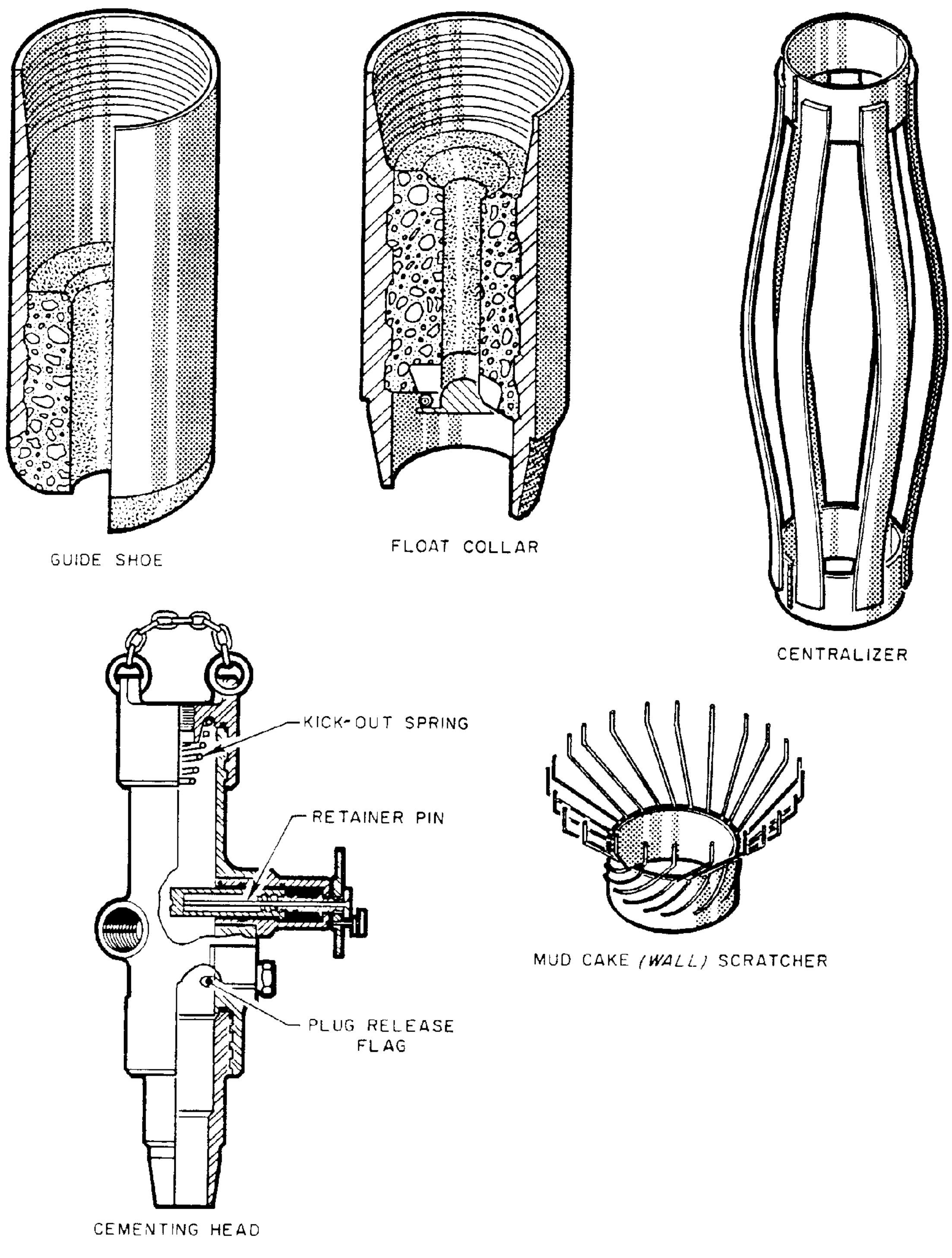


Figure 4-12: Casing Accessories

The Wellhead

This is the casing attachment to the B.O.P. or production (Christmas) tree. It is a permanent fixture, bolted or welded to the conductor pipe or surface casing. Wellheads installed on land rigs are located in the cellar, on the spider deck on jack-ups and fixed platforms, and on the seabed when used with barges, semi-submersibles and drillships.

The wellhead is the starting point for most blowout-preventer assemblies, and the vital link between the casing and B.O.P. stack. The conductor pipe is not usually provided with a pressure connection to connect the two. The surface casing is nearly always welded to the wellhead, and subsequent casing strings are inserted inside the wellhead housing and supported in a casing hanger (Figure 4-13). Hanger assemblies are designed to latch and seal inside the wellhead housing, so protection for the sealing surfaces is needed while drilling. To achieve this, removable sleeve-type protectors (called wear bushings) are installed in the wellhead above the hanger. These are removed prior to running the next string of casing.

Cementing

Oil well cementing is the process of mixing and displacing a cement slurry down the casing and up the annular space behind the casing where it is allowed to set, thus bonding the pipe to the formation. Cementing procedures are classified as primary or secondary. Primary cementing is performed immediately after the casing is run into the borehole. Its objective is to obtain an effective zonal separation and help protect the casing. Cementing also helps in the following ways:

- Bonds the casing to the formation
- Protects the producing formations
- Helps in the control of blowouts from high-pressure zones
- Seals off troublesome zones (i.e. lost circulation zones)
- Provides support for the casing
- Prevents casing corrosion
- Forms a seal in the event of a kick during drilling

Primary Cementing: Most primary cement jobs are performed by pumping the slurry down the casing and up the annulus. There are modified techniques for special situations, such as:

- Single-Stage cementing through casing (normal displacement)
- Multi-Stage cementing (for wells having critical fracture gradients or requiring good cement jobs on long strings)
- Inner string cementing through drillpipe (for large diameter pipe)

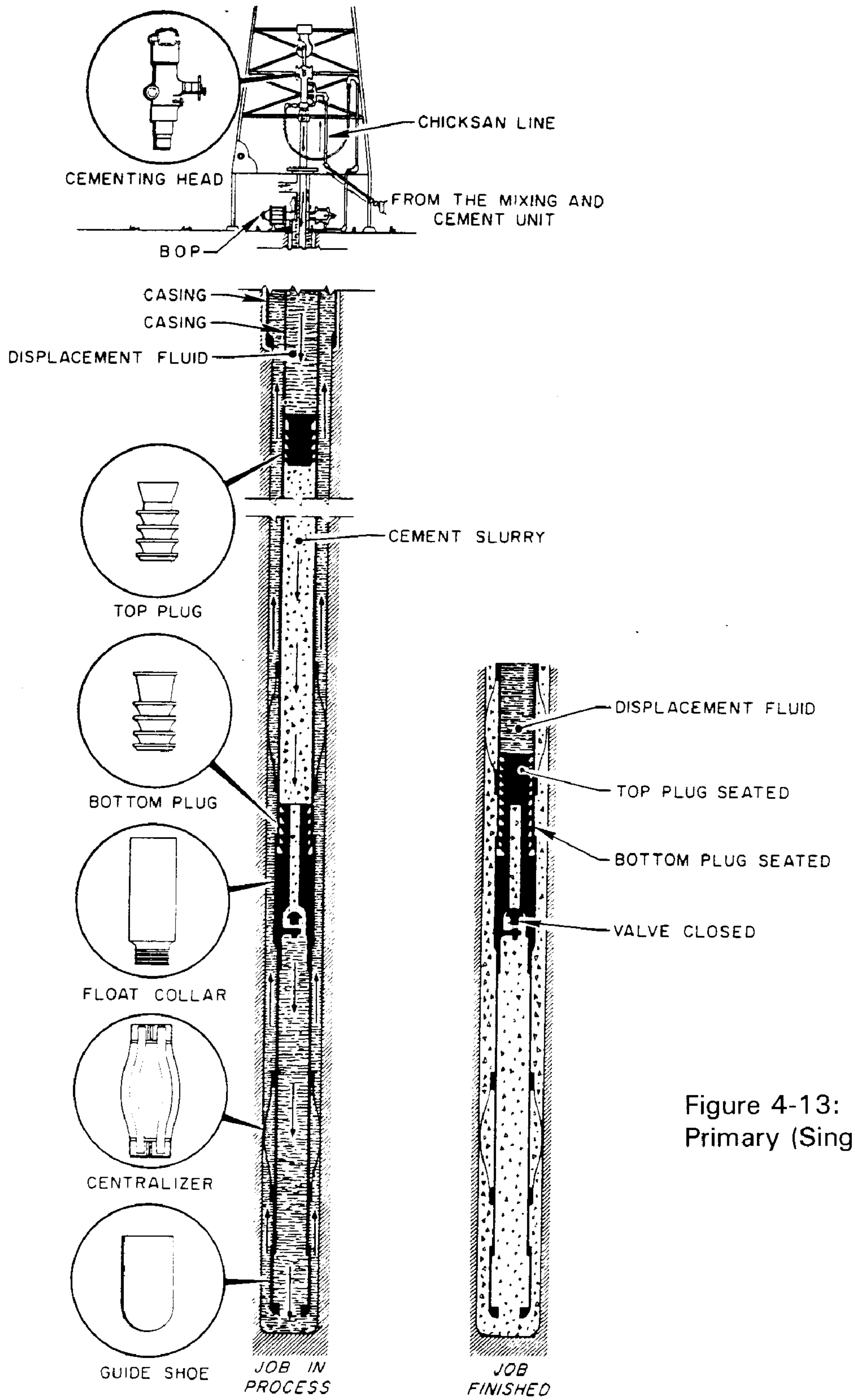


Figure 4-13: Primary (Single-Stage) Cementing

- Outside or annulus cementing through tubing (surface pipe or large casing)
- Multiple string cement (for small diameter pipe)
- Reverse circulation (critical formations)
- Delayed setting (critical formations and to improve placement)

The single-stage and multi-stage cementing methods are discussed below:

1. Single-Stage (normal displacement technique)

   With reference to Figure 4-13, the following procedures are conducted when completing a primary cement job. The general practice, once casing is set and circulation has been assured, is to pump a 10 to 15 barrel “spacer” ahead of the bottom (red) plug, which is immediately followed by the cement. The spacer serves as a flushing agent and provides a spacer between the mud and cement. It also assists in the removal of wall cake and flushes the mud ahead of the cement, thereby lessening contamination.

   Cement plugs consist of an aluminum body encased in molded rubber. Two plugs are usually contained in the cementing head to facilitate the operations. When the bottom plug reaches the float collar, the diaphragm in the plug ruptures to permit the cement to proceed down the casing and up the annulus. The top (black) plug, which is solidly constructed, is released when all the cement has been pumped. It is dropped on top of the cement, followed by drilling mud, to displace the cement from the casing. This plug causes a complete shut-off when it reaches the float collar.

   Pumping is stopped as soon as there is a positive indication (pressure increase) that the top plug has reached the float collar. Figure 4-14 shows a record of the circulating pressures while mixing and displacing from the casing to the annulus. To ensure good cement circulation and drilling mud displacement, movement of the casing, either by reciprocation or rotation, may be continued throughout the pumping and displacement operations.

2. Multi-Stage

   Devices are used for cementing two or more separate sections behind the casing string, usually for a long column that might cause formation breakdown if the cement were displaced from the bottom of the string. The essential tool consists of a ported coupling placed at the proper point in the string. Figure 4-15 shows the steps involved on a multi-stage cementing job. Cementation of the lower section of casing is done first, in the usual manner, using plugs that will pass through the stage collar without opening the ports. The multi-stage tool is then opened hydraulically by special plugs, and fluid circulated through the tool to the surface. Placement of cement for the upper section occurs through the ports which are subsequently closed by the final plug pumped behind the cement.

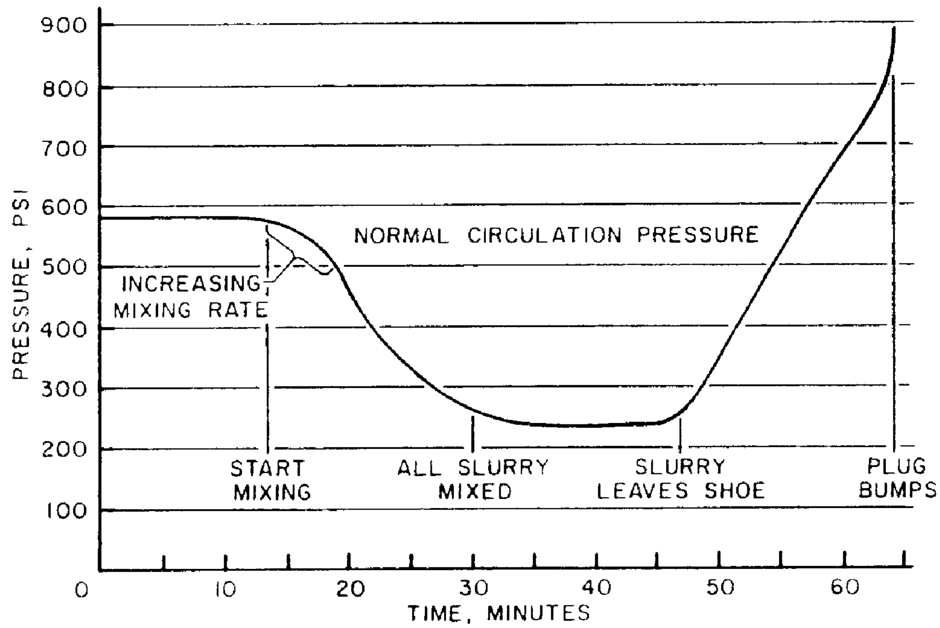


Figure 4-14: Record of Circulating Pressures While Cementing

Secondary Cementing: Secondary cement work is done after primary cementing, and includes:

- Plugging to another producing zone
- Plugging a dry hole
- Formation “squeeze” cementing

The most important use of squeeze cementing is to segregate hydrocarbon producing zones from those formations producing other fluids. Squeeze cementing is also used to:

- Supplement or repair a faulty primary cement job
- Repair defective casing or improperly placed perforations
- Minimize the danger of lost circulation zones
- Abandon permanently a non-producing or depleted zone
- Isolate a zone prior to perforating or fracturing

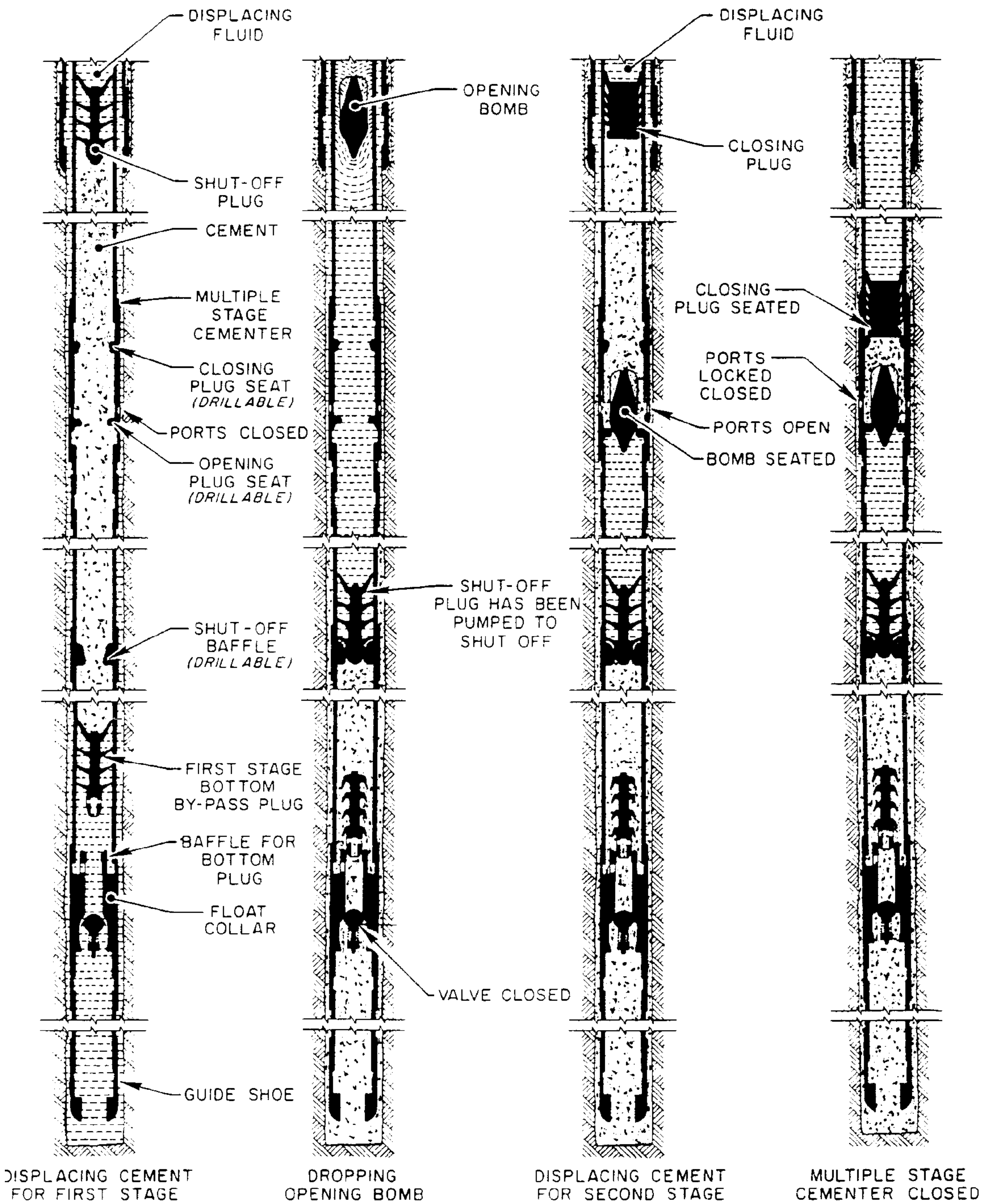


Figure 4-15: Successive Steps for Multi-Stage Cementing

Injection of the slurry is done under pressure through perforations. The pumping rate is slow enough to allow for dehydration and initial setting, or both. Pumping is continued until the desired “squeeze” pressure is reached.

Cement Classifications

As a result of efforts to find hydraulic cements which could be used under water, it was discovered that limes produced from impure limestones yielded mortars which were superior to those produced from more pure limestones. Such discoveries led to the burning of blends of calcareous and argillaceous materials. This process has been patented and is called “portland cement”.

The portland cements used for oil well cementing carry special API classifications, based on depth and temperature ratings (Figure 4-16). In areas of subnormal temperatures, API cements can be used at greater depths, whereas in areas of abnormally high temperatures, they can be limited to shallower depths. Normal API temperature gradient is considered to be 1.5^{o}F/100 feet of depth (Figure 4-17).

API Class	Mixing Water Gal/Sack	Slurry Weight Lb/Gal	Well Depth Ft	Static Temperature °F	Conditions of Use
A	5.2	15.6	0 - 6,000	80 - 170	
B	5.2	15.6	0 - 6,000	80 - 170	
C	6.3	14.8	0 - 6,000	80 - 170	When high early strength is required.
D	4.3	16.4	6 - 10,000	170 - 230	At moderate high temperature and pressure.
E	4.3	16.4	6 - 14,000	170 - 290	At high temperature and pressure.
F	4.3	16.4	10 - 16,000	230 - 320	At extra high temperature and extra high pressure.
G	5.0	15.8	0 - 8,000	80 - 200	Can be used as basic cement or with accelerator and retarder for a wide range of uses.
H	4.3	16.4	0 - 8,000	80 - 200	

Figure 4-16: API Cement Classifications

Well Depth Ft	Bottomhole Temperature Static °F	Bottomhole Circulating Temperature °F		
		Casing	Squeeze	Liner
2,000	110	91 (9)*	98 (4)*	91 (4)*
6,000	170	113 (20)	136 (10)	113 (10)
8,000	200	125 (28)	159 (15)	125 (15)
12,000	260	172 (44)	213 (24)	172 (24)
16,000	320	248 (60)	271 (34)	248 (34)
20,000	380	340 (75)	- - - -	- - - -
* Time to reach BHC temperature.				

Figure 4-17: Basis for API Well Stimulation Test Schedules

Cement Additives

A large percentage of the world's cementing jobs utilize bulk systems rather than manual handling in sacks. This allows the preparation and supply of compositions tailored to suit the requirements of any well condition. As with drilling fluids, additives are used to tailor the systems. Additives are used to:

- Reduce slurry density and increase slurry volume (Lightweight Additives)
- Increase thickening time and retard setting (Retarders)
- Reduce waiting-on-cement time and increase early strength (Accelerators)
- Reduce water loss, help sensitive formations, and help prevent premature dehydration (Fluid Loss Additives)
- Increase slurry density to restrain pressures (Heavyweight Additives)

Mixing and Other Surface Equipment

The mixing system on any cementing operation, proportions and blends the dry cementing composition with the carrier fluid. When this is achieved, a cementing slurry with predictable properties can be supplied to the cementing head. The most widely used mixing method is the jet-type mixer (Figure 4-18). A stream of water mixes with cement by passing through the mixer tub, creating a vacuum which pulls the dry cement into the tub from the hopper immediately above. As the cement enters the jet stream of water, it is thoroughly mixed by the turbulent flow that occurs in the discharge pipe.

Control of mixing speed is regulated by the volume of water forced through the jet and by the amount of cement in the hopper. The mixed cement is pumped from the mixing tub to the cementing pump.

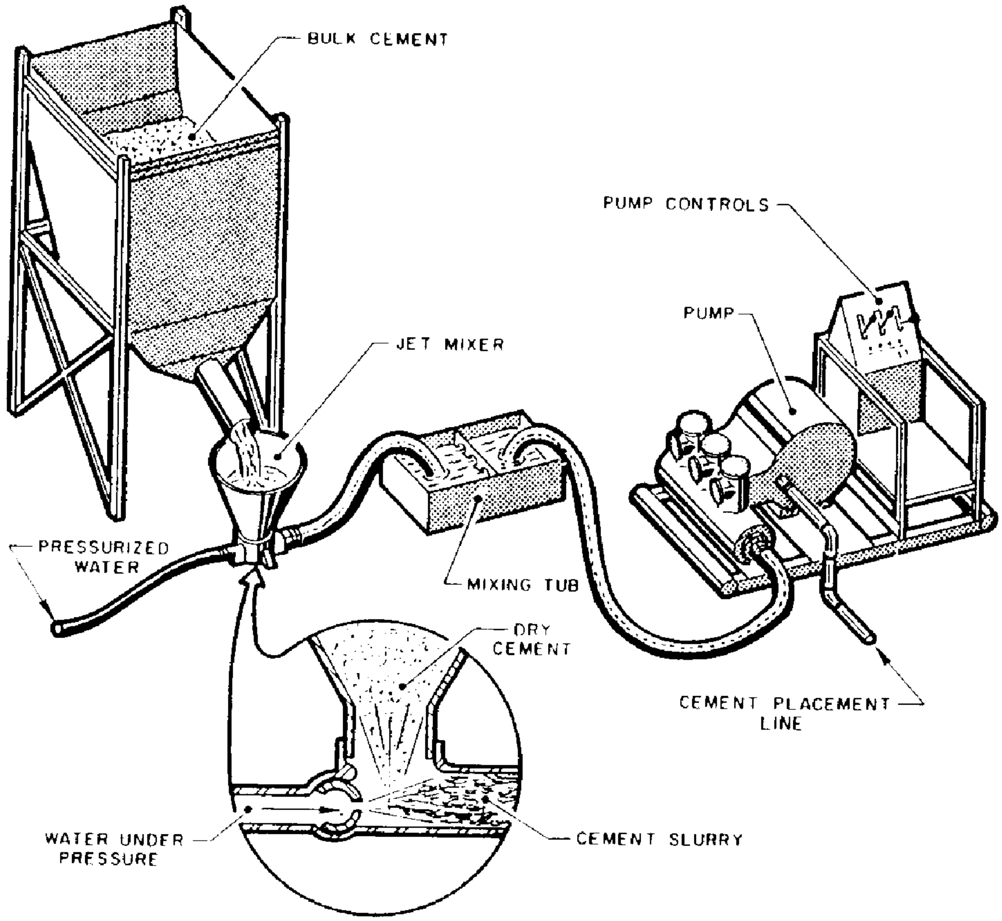


Figure 4-18: Typical Cement Mixing and Pumping Operations

The cementing unit is basically an assembly of special purpose pumps. As the casing is sometimes reciprocated or rotated while cement is being pumped, the lines from the cement pump to the rig floor must be flexible. This is achieved by the use of steel pipe with swivel joints, called “chicksan lines”.

Cement Job Considerations

Cement systems cover a density range from 10.8 to 22 lbs/gal. Slurry density is directly related to the amount of mixing water and additives in the cement and the amount of slurry contamination from the drilling mud. In field operations, slurry control is usually maintained by testing the properties, as with the drilling mud.

The volume of cement required for a specific fill-up on a casing job is calculated volumetrically or through the use of tables. The use of a caliper survey is used to determine the approximate hole volume.

To determine the height of the cement column in the annulus, a temperature log is run 12 to 24 hours after placement. Cement drying is an exothermic reaction, therefore it is possible to locate the top of the cement by an anomaly in a temperature log, as seen in Figure 4-19. This log can also be used to determine the quality of the bond between casing and formation. A poor bond is shown as a variation in temperature which is out of line with the normal temperature gradient. A “Cement Bond Log” (CBL), measures the attenuation of an acoustic signal, and can be used to determine cement bonding between casing and formation. With careful interpretation, the CBL can be used to determine the compressive strength of the cement.

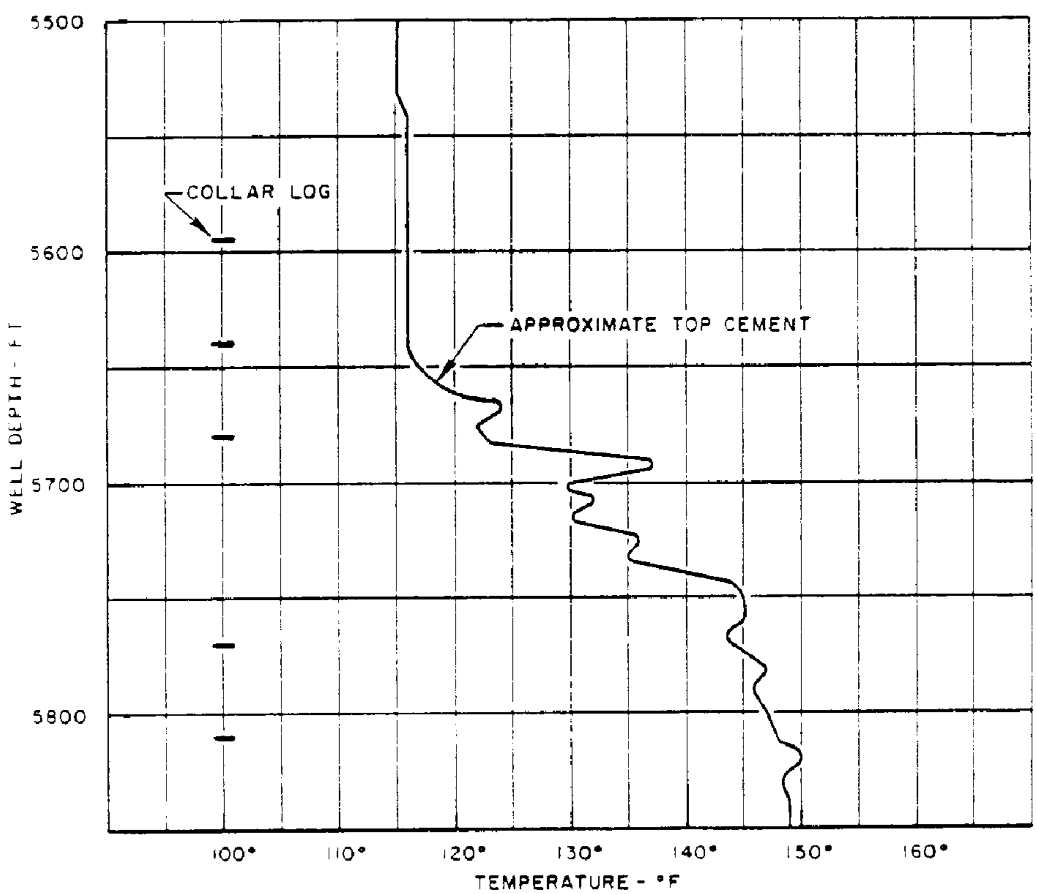


Figure 4-19: Temperature Survey Showing Top of Cement

Vertical, Directional and Horizontal Drilling

Controlled directional drilling is the science of directing a wellbore along a predetermined course to a target located a given distance from the vertical. Regardless of whether it is used to hold a wellbore as close as possible to the vertical or to deliberately deviate from the vertical, the principles of application are basically the same.

Vertical Drilling

No hole is drilled exactly vertically from top to bottom. It is desirable on most wells to drill as near to vertical as possible. This ensures that vertical depth is close to measured depth, and restricts the hole problems that can occur with deviated wells.

It is generally accepted that a straight or vertical well is one that:

- Stays within the boundary of a “cone”, as specified by the client (usually about 3 degrees)
- Does not change direction rapidly (no more than 3 degrees per 100 ft of hole) and form a “dogleg”.

In order for the driller to be sure he is maintaining a vertical hole within the limits set out in the drilling contract, periodic measurements must be taken by the drilling crew. If any deviation has occurred, it must be recorded and compared with the amount of deviation permissible in that section of hole. In straight-hole drilling, the measuring device is used to determine inclination or drift (the azimuth of the borehole is not necessary).

Measuring Inclination: The drift survey instrument (Figure 4-20) can be (1) run into and pulled out of the drillpipe on a “sand line”, (2) dropped into the pipe and retrieved with an overshot assembly, or (3) dropped into the pipe and recovered by tripping out of the hole. The record of the inclination angle is made when a paper disk is punched by a pendulum-balanced stylus, inside the instrument. Concentric circles printed on the discs are marked to show the angle of inclination from the vertical. In this example the hole inclination is 4 degrees.

Preventing and Correcting Deviation: Where deviation is expected, it can be inhibited by using a stiff bottomhole assembly (a BHA with many stabilizers). This will align the bit with the hole already drilled and resist any change in direction.

To straighten a crooked hole, the pendulum principle is often utilized. By removing any stabilizers placed just above the bit, retaining an upper stabilizer, and by using light weight-on-bit (as shown in Figure 4-21), the drill collars will exert the pendulum effect to straighten the borehole.

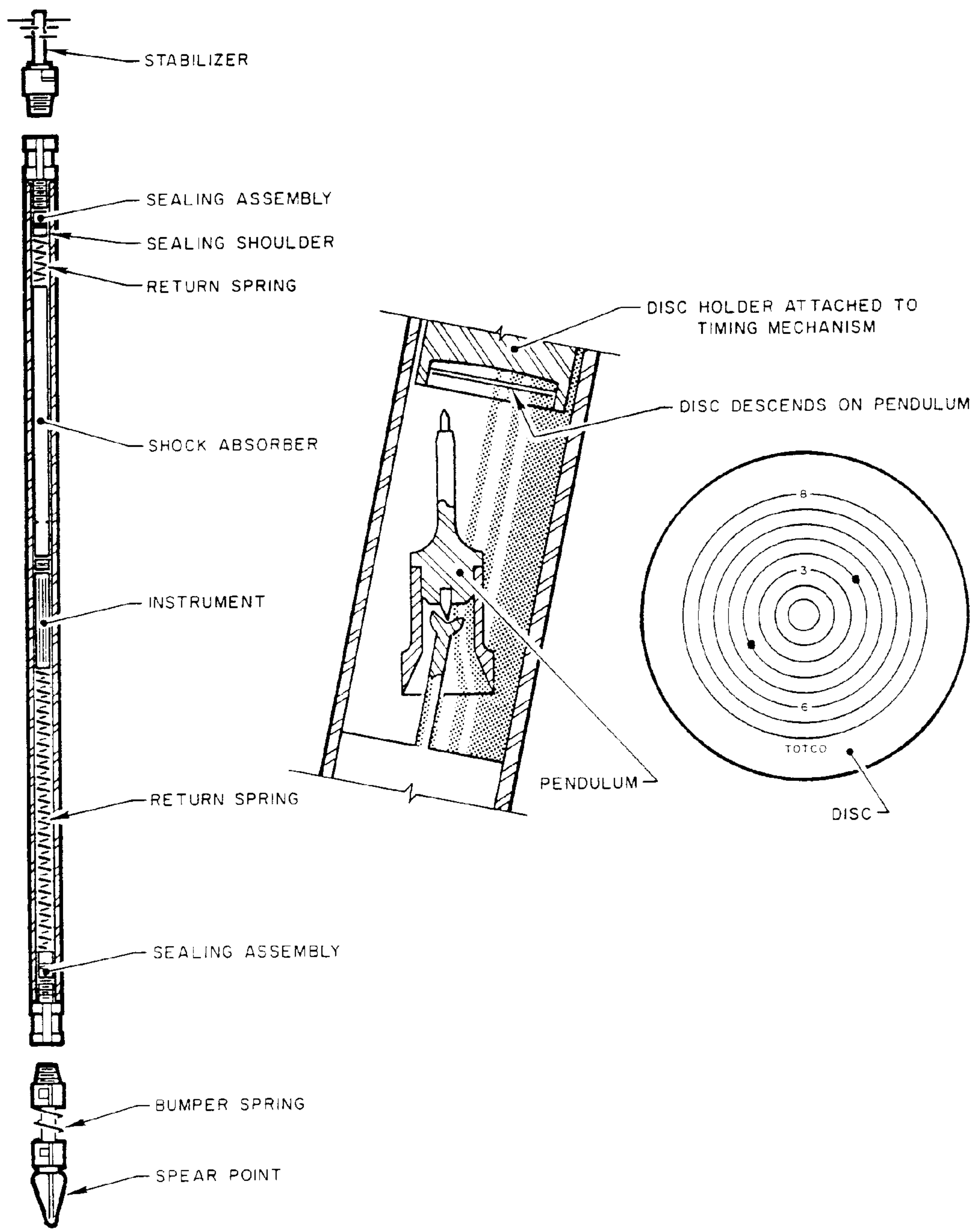


Figure 4-20: Drift Survey Instrument

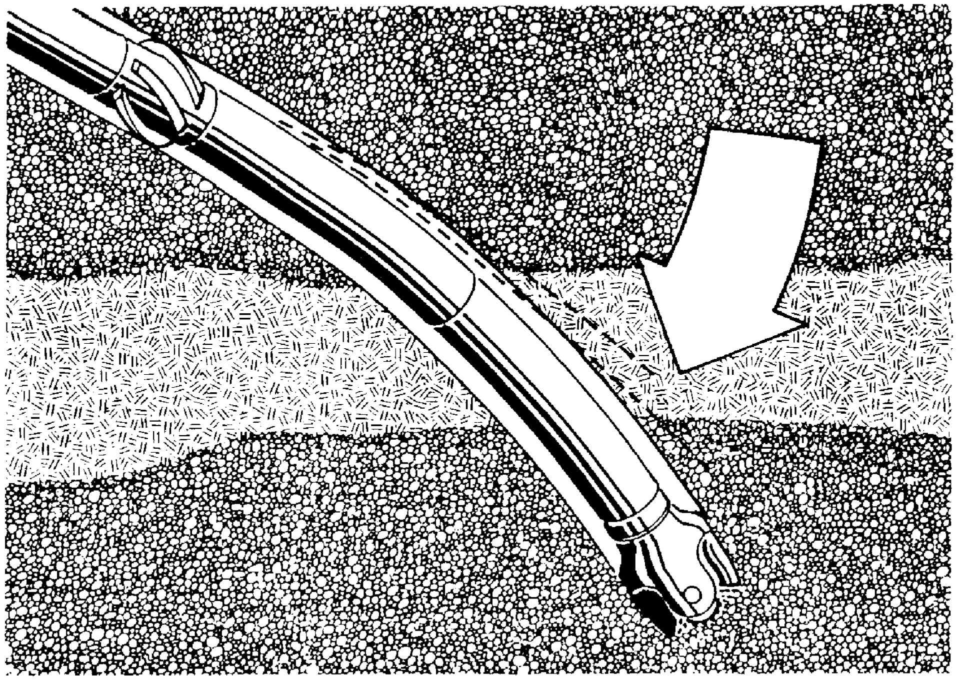


Figure 4-21: The Pendulum Effect

Directional Drilling

The most common applications of directional drilling are illustrated in Figure 4-22 and discussed briefly below:

- Multiple wells from artificial structures: Today's most common application of directional techniques is in offshore drilling, where an optimum number of wells can be drilled from a single platform. This operation greatly simplifies production techniques and gathering systems (a governing factor in the economic feasibility of the offshore industry).
- Fault drilling: Another application is in fault control, where the borehole is deflected across or parallel to a fault for better production. This eliminates the hazard of drilling a vertical well through a fault plane, which could slip and shear the casing.
- Inaccessible locations: The same basic techniques are applied when an inaccessible location in a producing region dictates a remote rig location, such as production located under river beds, just offshore, under mountains, under cities, etc.

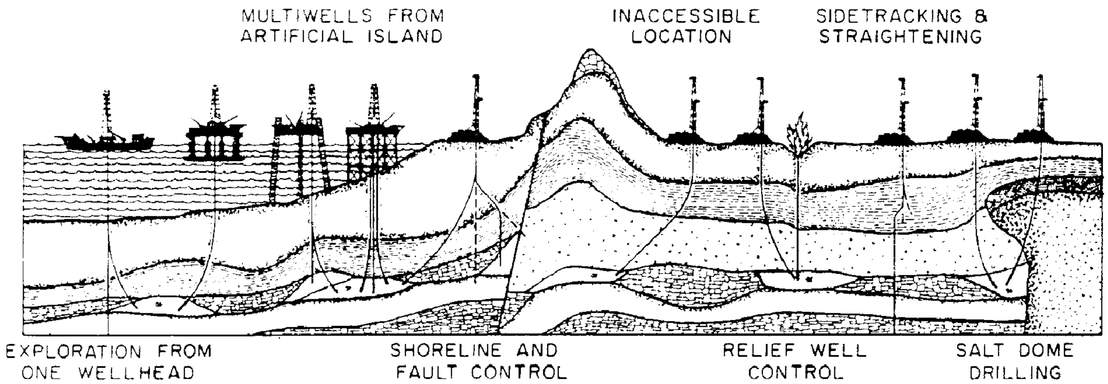


Figure 4-22: Applications of Directional Drilling

- Sidetracking and straightening: This is used as a remedial operation. Either to sidetrack an obstruction by deviating the wellbore around and away from the obstruction, or to bring the borehole back to vertical by straightening out crooked holes.
- Salt Dome drilling: Directional programs are also used to overcome the problems of salt dome drilling. This means reaching the producing formations which often lie underneath the overhanging cap of the dome.
- Relief wells: Directional drilling was first applied to this type of well, so that mud and water could be pumped into and kill a blowout.

Basic Hole Patterns: A carefully conceived directional drilling program, based on geological information, knowledge of mud and casing programs, target area, etc., is used to select a hole pattern suitable for the operation. Experience has shown that most of the deflected boreholes fit one of the types illustrated in Figure 4-23.

- Type I is planned so that the initial deflection is obtained at a shallow depth (approximately 1000 feet), and the angle is maintained as a “locked in” straight angle approach to the target. This pattern is mainly used for moderate depth drilling in areas where the producing formation is located in a single zone, and where no intermediate casing is required. It is also used to drill deeper wells requiring a larger lateral displacement.
- Type II, called the “S” curve pattern, is also deflected near the surface. The drift is maintained, as with Type I, until most of the desired lateral displacement is obtained. The hole angle is then reduced to vertical to reach the target.
- Type III is planned such that the initial deflection is started well below the surface and the hole angle maintained to the bottomhole target.

This pattern is particularly suited to special situations, such as fault or salt dome drilling, or any situation requiring redrilling or repositioning of the bottom part of the borehole.

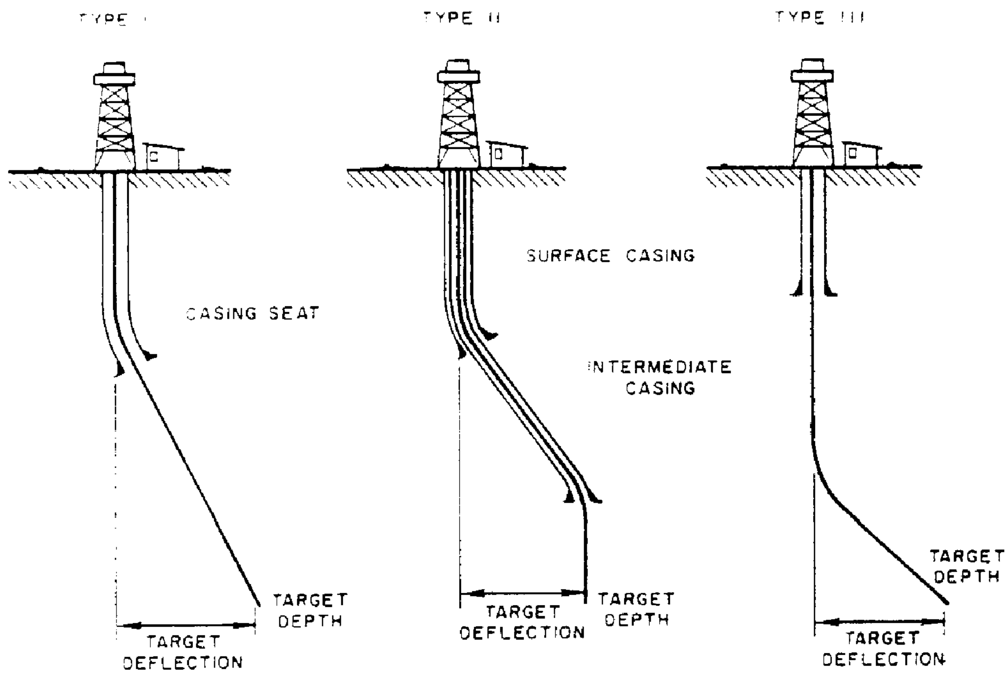


Figure 4-23: Basic Hole Patterns

Deflection Tools: A prime requirement for directional drilling is suitable deflection tools, along with special bits and other auxiliary tools. A deflection tool is a mechanical device that is placed in the borehole to cause the drill bit to be deviated from the present course of the borehole. There are numerous deflection tools available. The selection depends upon several factors, but principally upon the type of formation where the deviation is to start. The most common tools used for deflection are:

- Downhole Hydraulic Motors (with a bent sub)
- Jet Bits
- Whipstocks

1. Downhole Hydraulic Motors

   The downhole motor with a bent sub is the most widely used deflection tool. It is driven by the drilling mud flowing through the motor to produce rotary power downhole, thus eliminating the need for rotating the drillpipe.

   The first variation of the downhole motor (illustrated in Figure 4-24) is the turbine type motor or “turbodrill”. It consists of a multistage vane-type rotor and stator, a bearing section, a drive shaft, and a bit rotating sub. The first stage is comprised of the rotor and stator of identical profile. The stator is stationary and deflects the flow of drilling mud to the rotor, which is locked to the drive shaft, and thus transmits the rotary motion to turn the bit.

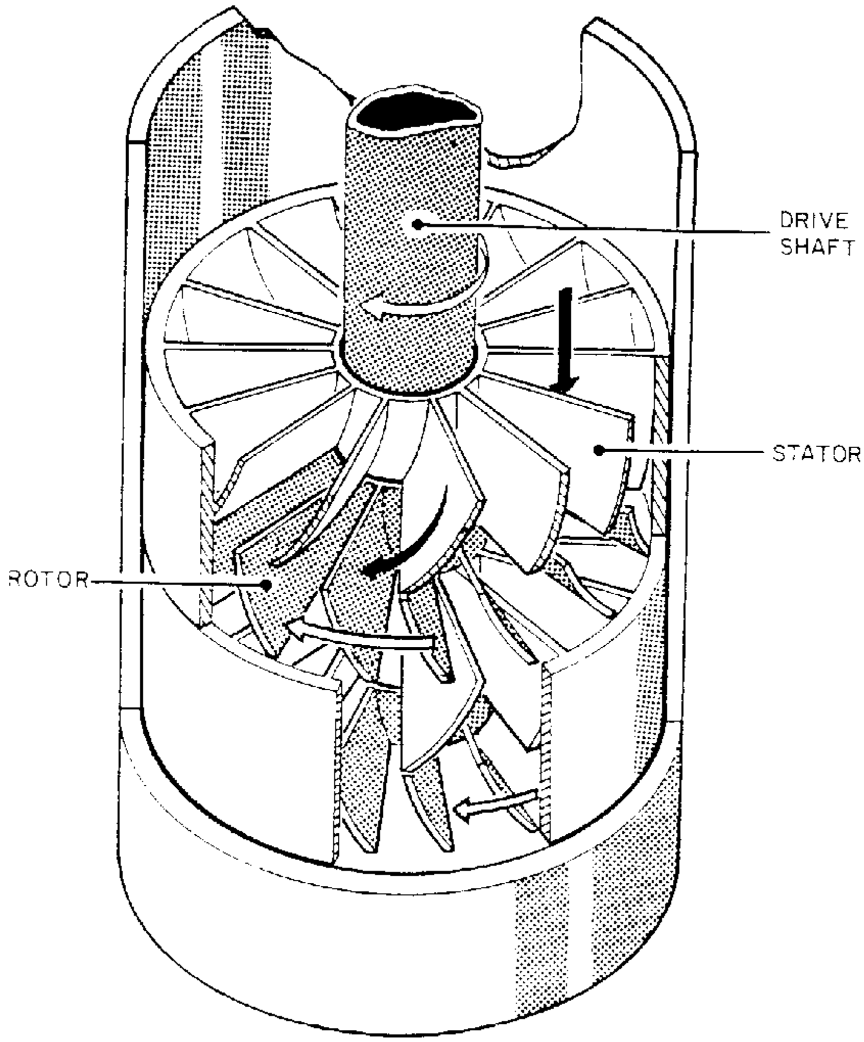


Figure 4-24: Schematic Cross-Section of a Turbine Motor

The second variation of the downhole motor is the "positive displacement motor" (PDM). It consists of a two-stage helicoid motor, a dump valve, a connecting rod assembly, and a bearing and shaft assembly. The helicoid motor has a rubber lined spiral cavity with an elliptical cross-section, which houses a sinusoidal steel rotor. As the mud is pumped, it is forced downward between the rotor and spiral cavity. The rotor is thus displaced and turned by the pressure of the fluid column, which in turn powers the drive shaft and results in a rotational force that is used to turn the bit.

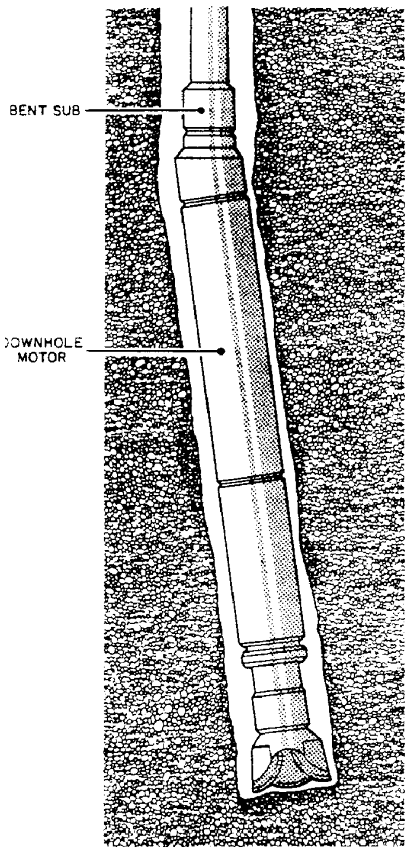


Figure 4-25: Downhole Motor Deflected with a Bent Sub

The bent sub (as seen in Figure 4-25), is used to impart a constant deflection to the tool. Its upper thread is cut concentric to the axis of the sub body, and its lower thread is cut with an axis inclined 1 to 3 degrees in relation to the axis of the upper thread. In addition, the “hydraulic bent sub” can be locked into position for straight drilling, or unlocked and reset for directional drilling.

Both downhole motor types can be used with the following assembly:

- A full-gauge drill bit
- The downhole motor
- The bent sub
- A non-magnetic drill collar
- The remainder of the drillstring

2. Jet Bits

Where subsurface formations are relatively soft, the borehole can be deviated by using a jet bit. In this method, all but one of the jet nozzles are closed off or reduced in size. The opened nozzle is oriented in the proper direction on-bottom, and the pumps are started (the drillstring is not rotated). Being a few feet off

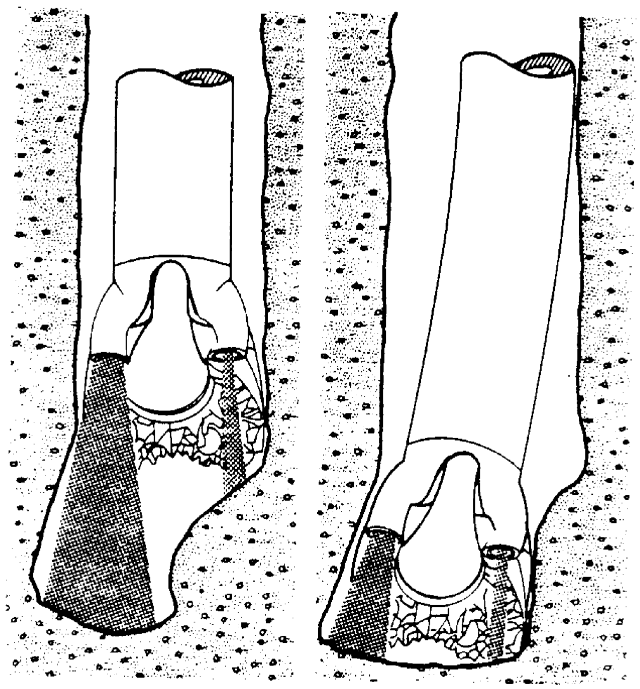


Figure 4-26: Deflection by Jetting

bottom, and the pumps on, the jetting action literally washes the formation away (Figure 4-26). After jetting has set a course, the drillstring is rotated and weight added. Since the washed-out section is the path of least resistance, the bit and drillstring will follow it. Extra weight is then applied to bow the collars, and the drillstring continues until the correct hole angle is attained.

3. Whipstocks

The standard “removable” whipstock (Figure 4-27) is used to initiate the deflection and direction of a well, sidetrack cement plugs, or straighten crooked holes. It consists of a long inverted steel wedge, that is concave on one side to hold and guide a whipstock drilling assembly. It also has a chisel point at the bottom to prevent the tool from turning, and a heavy collar at the top to help withdraw the tool from the hole.

Figure 4-27: Deviating with a Whipstock

The “circulating” whipstock is run, set and drilled like a standard whipstock. In this case, the drilling mud flows through a passage to the bottom of the whipstock and circulates the cuttings out of the hole, ensuring a clean seat for the tool. It is most efficient for washing out bridges and bottom hole fills.

The “permanent” casing whipstock is designed to remain permanently in the well. It is mainly used to bypass collapsed casing, junk in the hole or to reenter and drill out old wells. After the bit has drilled below the whipstock, increased weight is applied until approximately 20 feet of pilot hole has been drilled. The whipstock is then retrieved and the pilot hole opened to full gauge with pilot bit and hole opener.

Deflection Tools in General: Downhole motors present many advantages over the whipstock. When jetting becomes impractical, they permit a full-gauge hole at the "kick-off point", thus eliminating costly follow-up trips to open the hole. Orientation is also more accurate since the motors penetrate along a smooth, gradual curve in build-up and drop-off sections. Corrections, if needed, can be made downhole without making a trip. Finally, downhole motors eliminate the need for clean-up trips due to bridges, doglegs, etc., since the tool can be circulated, rotated and drilled to bottom.

Orientation of Deflection Tools: A widely used and practical way of determining orientation, is with the "Single Shot Direct Orientation Instrument", which is run down the drillpipe on a wireline. A monel (non-magnetic, copper and nickel alloy) collar is used directly above the deflection tool, so that the mechanisms in the survey instrument indicate true azimuth and inclination. When the survey instrument is retrieved at the surface, the recording disc is developed and the relationships between azimuth, inclination, and direction of the tool face (as they appear at the bottom of the hole) can be seen. Only minor calculations, including an allowance of declination, are needed to determine how much the drillstring must be rotated to position the tool face in the desired direction.

After the drillstring has been rotated the calculated number of degrees, a check survey is run to determine whether the deflection tool also turned the same number of degrees and is facing correctly. Several attempts at rotating the tool may be needed before it is facing properly, and each attempt is checked with a survey. Once the deflection tool is facing properly, the kickoff can begin.

Measurement While Drilling (MWD) tools are becoming increasingly popular for directional surveys, because they can provide continuous surveys, without the non-drilling time being spent on single-shot surveys. This method utilizes an instrument that transmits the survey data (azimuth, inclination, tool face position) via mud pulse telemetry. This information is then available for surface readout. By observing the surface readout, the operator can keep a constant check on the direction in which a downhole motor is facing. As drilling proceeds, hole azimuth can be maintained on course and direction changes made when necessary. For this reason, a deflection tool is often referred to as a "steering tool".

Drilling the Deviated Section of Hole: Once the initial deflection and direction of the well are established, directional control is accomplished with conventional drilling techniques. The directional engineer determines the inclination and azimuth of the borehole at specific depths using survey methods (single-shot or MWD). Following the directional engineer's instructions, it is up to the driller to apply certain drilling techniques to drill the hole, so that it is maintained on course to the target. Once the hole is kicked-off from the vertical, proper use of the BHA, application of weight-on-bit, adjustments to rotary speed and flow rates are used to maintain the course. If the borehole changes direction, the directional engineer must use deflection tools or other methods to bring it back on course.

After a section of hole has been drilled, and before it is cased, a “multiple shot” survey can be run to obtain a complete directional survey. Records are taken at regular time intervals as the tool is pulled out of the hole. The tool operator takes note of the time and depth of each survey station and uses this information when reading the film, upon which the surveys are recorded.

Engineering and Formation Evaluation Considerations: There is a tendency in a deviated well for the drillstring to rest on the side of the borehole. This tendency increases with increased inclination. It is estimated that, in a 70 degree deviated hole, over 90 percent of the drillstring will be resting on the side of the low side of the borehole. Rotation of the drillstring causes erosion, and therefore contamination of the cuttings samples. Engineering factors to be considered include:

- Increased vertical drag
- Increased rotary torque
- Increased possibility of differential sticking
- Excessive wall friction that creates a rolling action, which affects directional control

Horizontal Drilling

There are many reasons for operators to drill horizontal wells, the most important being the ability to increase production. More of the reservoir is penetrated when drilling horizontally allowing more of the formation to “produce”. If the operator is drilling a fractured reservoir, more of the fractures are connected by drilling horizontally, as opposed to hitting only a few when drilling vertically or directionally. Many of the reservoir production parameters are also enhanced (gravity drainage, minimizing fluid coning problems, etc.).

Effective reservoir management, involving the geological, drilling and production teams will dictate the type of horizontal well drilled. There are three basic borehole patterns (Figure 4-28).

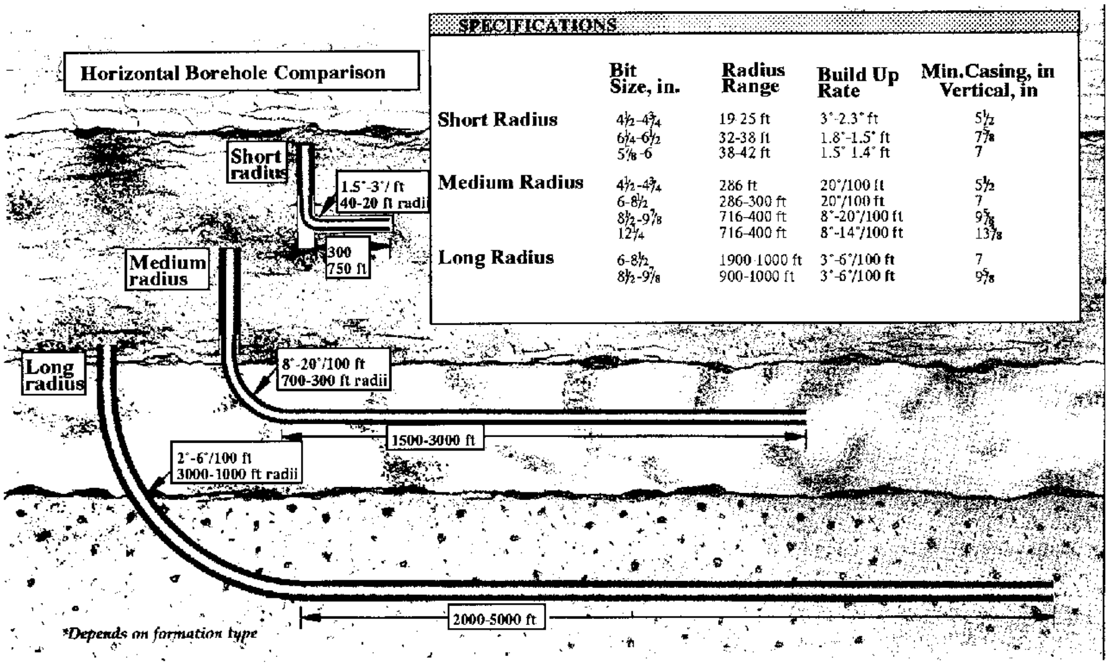


Figure 4-28: Horizontal Wellbore Patterns

- Short Radius Well: This borehole pattern is used when there are “small” targets with vertical fractures and low energy production characteristics. Build rates are between 1.5 to 3 degrees per foot, generally going horizontal over a 20 to 40 foot interval. The horizontal section is rarely longer than 1000 feet.
- Medium Radius Well: This borehole pattern is used when there are thin, low permeability reservoirs over a limited extent. Build rates are between 8 to 20 degrees per 100 feet. The horizontal intervals may extend up to 4000 feet.
- Long Radius Well: The long radius borehole pattern is used for the “extended reach” drilling programs, and can be used to navigate around fault blocks. Build rates are between 2 and 6 degrees per 100 feet, and the horizontal intervals can exceed 5000 feet.

Inverted Drillstrings: In horizontal wells, drillstrings are typically run inverted, with no drill collars. The drillpipe is run in compression, and heavy-weight pipe is normally placed in the more vertical portion of the borehole to provide weight to the BHA.

Curved Assemblies: These assemblies are used in the short radius wells to assist in the building of the sharp angles. These assemblies are made up of a non-rotating shell, consisting of “cut” drillpipe (making it flexible) and an internal drive shaft that imparts the rotation to the vertical section of the drillstring. A permanent whipstock is used to start short radius drilling.

MWD Tools: Measurement-While-Drilling tools are necessary in horizontal drilling. They provide constant inclination information to ensure the drillstring does not exit the reservoir (either upwards or downwards), and provides the necessary formation evaluation logs (since wireline logging tools cannot reach the entire length of horizontal wells).

Additional Drilling Considerations: Several other requirements are necessary when drilling horizontal wells: (1)Because extensive reaming is required, top drive drilling rigs are usually the most effective, (2) cuttings removal is paramount, so mud properties and hydraulic parameters must be optimized to ensure the borehole is clean, and (3) the bit's gauge surface should ensure an in-gauge hole and it's profile flat and short to increase sidecutting and steerability.

Formation Evaluation Aspects: The geological aspects of formation evaluation, especially in horizontal wells, takes on three main roles; (1) finding the reservoir, generally using marker horizons, (2) remaining in the reservoir, to maximize the well bore exposure over production intervals, and (3) evaluation of the reservoir, to provide the engineer and geologist with information for the decision-making process.

Horizontal wells provides the geologist, petrophysicist and engineers with an opportunity to evaluate the reservoir in a manner not available from vertical or directional well patterns. The lateral section of the well greatly increases the interval of the reservoir for analysis. For this reason, horizontal wells will continue to be attractive.

Fishing

When great stress is placed on downhole equipment, the probability exists that sooner or later there will be a mechanical failure and some part of the equipment will be left in the borehole. Another common source of trouble is the drillstring and associated equipment becoming “stuck” in the borehole. The technique of removing pieces/section of equipment is called “fishing”.

Situations Requiring a “Fishing Job”

These fall into three categories:

- Drillstring Fatigue Failures
- Stuck Pipe
- Foreign objects in the hole (junk)

Drillstring Fatigue Failures: The following are some of the possible causes:

- Fatigue failures caused by excessive stress in the drillstring, as when the rotary table continues to turn when the lower portion of the drillstring becomes stuck - called a “twist-off”.
- Parting of the drillstring because of excessive pull when attempting to free equipment which has become stuck.
- Mechanical failure of parts of the drill bit, causing some part of the bit to become lost.

Stuck Pipe: The following are some of the possible causes:

- Mechanical sticking because of stuck packers or other downhole assemblies, crooked pipe, and junk in the hole.
- “Key seating” caused when the drillpipe under tension wears a slot into the wall of the hole, as seen in Figure 4-29.
- Bridging, due to caving or swelling formations
- Differential sticking, caused when the pipe comes in contact with a permeable formation and the string is held in place by the differential pressure existing between the mud column and the formation, as seen in Figure 4-30.
- Sloughing borehole, a problem usually associated with shale, when the shale absorbs water from the drilling mud. This reduces stability of the shale section, causing it to expand perpendicular to the bedding plane, and sloughs off into the borehole.

Foreign Objects in the Borehole: These include tools and other undrillable objects which have been dropped into the hole, parts of the drill bit, or wireline sondes and cable.

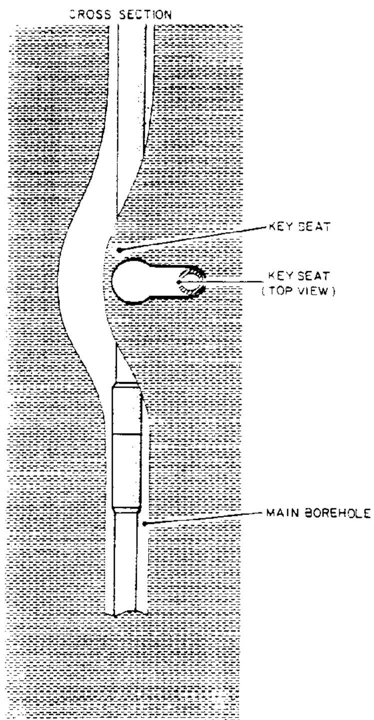


Figure 4-29: Key Seating

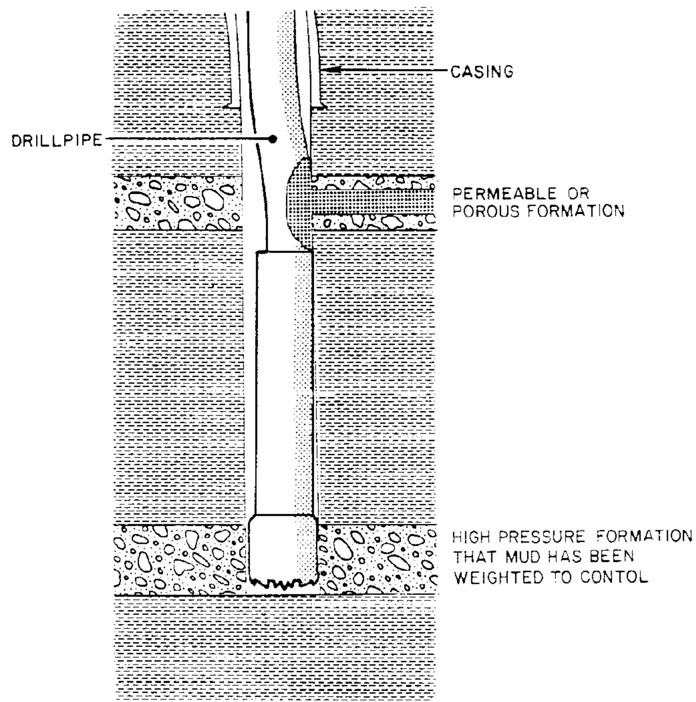


Figure 4-30: Differential Sticking

Fishing Tools

Many of the tools used to recover equipment are specially designed for the particular job. However, due to the similarity of equipment used in most drilling operations, certain standard fishing tools have been developed. A broad classification of fishing tools is:

- Tools used to recover miscellaneous equipment (junk)
- Tools used to recover pipe (fish)

Fishing for Junk: When a relatively small piece of equipment is lost in the borehole, it may be retrieved using one of the following tools (Figure 4-31).

- <u>“Junk” or “Boot” sub</u>: This is run immediately above the bit to catch small junk thrown up by turbulence. It is normally run before running a diamond bit so that no fragments can damage the bit.

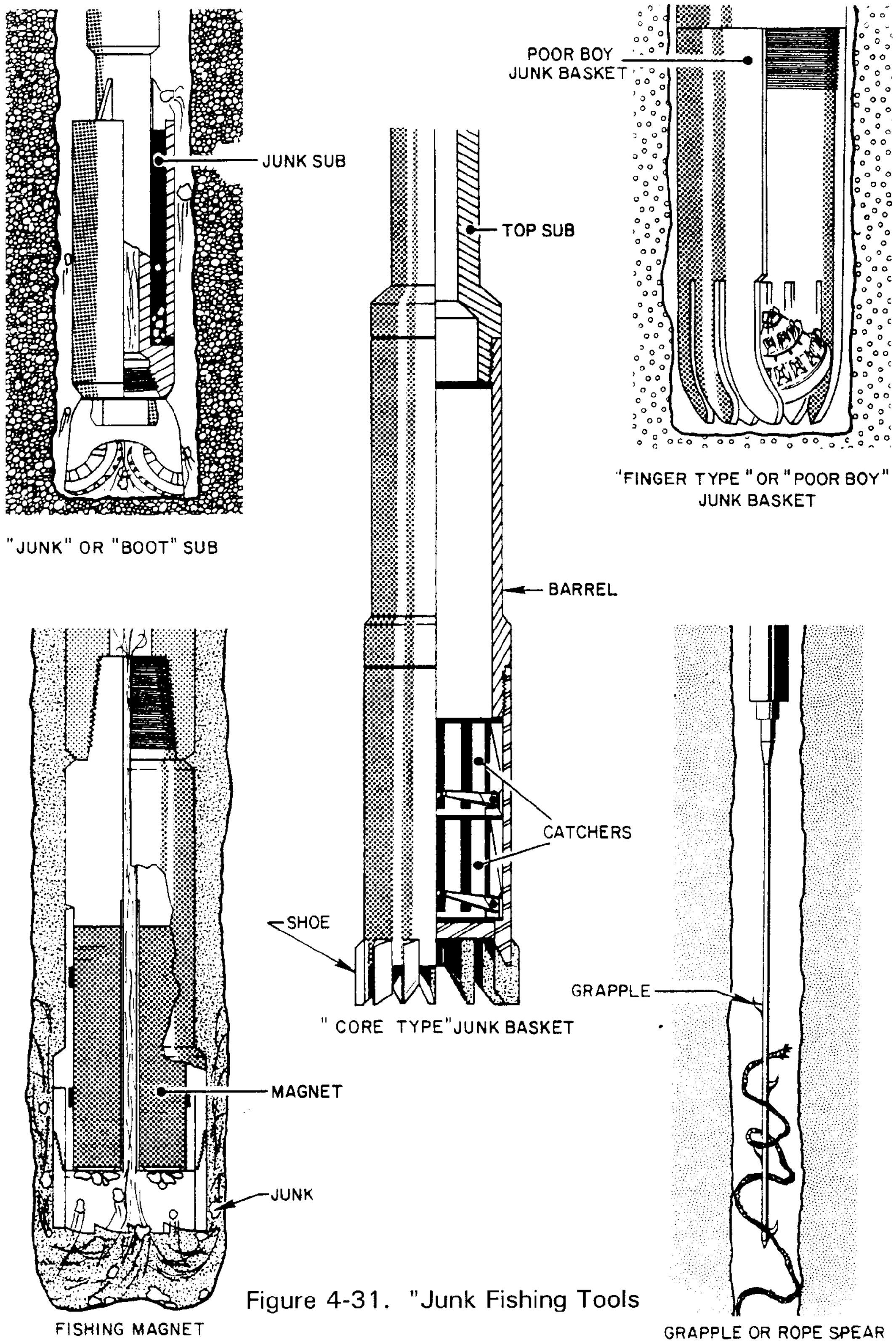


Figure 4-31: "Junk Fishing Tools

- "Finger-type" or "Poor Boy" Junk Basket: This cuts a small core, after which weight is applied to bend the beveled fingers inward to trap the junk inside. This can be made "on-the-spot" from casing.
- Core-type Junk Basket: This is essentially a mill shoe basket, which cuts a small core to trap the junk, and has catchers (fingers) which grip the junk on the trip out.
- Fishing Magnet: This is used for picking up steel fragments.
- Jet Bottomhole Cutter: This is used when the junk is so large or oddly shaped that it cannot be readily retrieved with regular junk baskets. It breaks the junk up into smaller pieces by use of an explosive charge.
- Grapple or Rope Spear: This is used to retrieve wireline cable in the hole.

Fishing for Pipe: When the drillstring has actually parted or is stuck in the borehole, the operation for correcting the situation is called "fishing". If the fish cannot be recovered, then it is cemented off and the borehole is sidetracked around it. Some of the tools used for fishing are described below and illustrated in Figure 4-32.

- Mill: Milling is sometimes necessary in order to dress the top of a fish so that the selected fishing tool is able to make a firm positive catch. Mills usually are bladed or blunt, tungsten carbide coated, and are attached to the end of the drillstring to be lowered into the borehole.
- Overshot: This is probably the first tool to be used when it is established that the top of the fish is relatively smooth. It will slide over the fish, center it, then use a rotary tap or slips to engage the fish.
- Wall-Hook Guide: This is used if the top of the fish is located in a washed out section. It takes the place of the regular guide on the bottom of an overshot. It will engage the fish and guide it into the overshot.
- Jar: This is used when the drillstring is stuck or when a fish is caught in an overshot and cannot be pulled from the borehole. In normal drilling, the jar is placed in the heavy weight pipe section, while in fishing it is located directly above the fishing tool. Jarring provides a method of giving an upward jerk to free the pipe. It works similar to a trip-hammer.

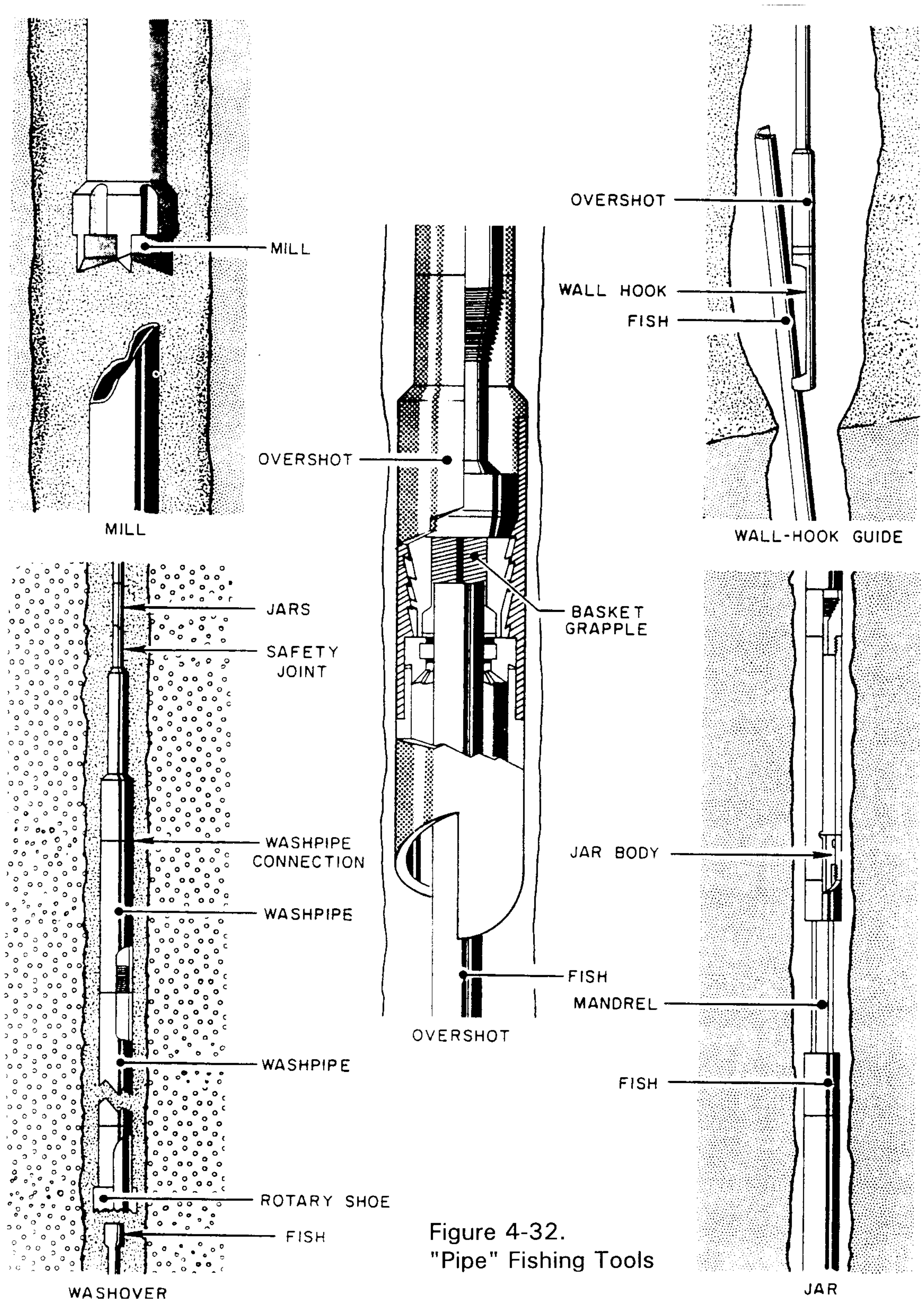


Figure 4-32: "Pipe" Fishing Tools

- Free-Point Indicator and String Shot: When jarring has not been successful, this is used to determine at what point in the borehole the fish is stuck. It is an electronic instrument that can sense torque or pipe movement. It is lowered on a wireline as far as possible and raised slowly while the drillstring is stressed. Below the stuck point, no torque will be sensed. When the instrument gives a positive indication, the "free point" is reached.

  The free point indicator is raised until string shot is positioned opposite the nearest tool joint (or one or two tool joints above the stuck point). Left-hand torque is applied to the drillstring by the rotary table, and the primacord string shot is exploded. Loss of torque in the drillpipe is a definite indication that the tool joint has been loosened. The "backoff" is completed by further left-hand rotation and by picking the pipe up a few feet.

- Washover: This is a large diameter pipe with a rotary cutting shoe on the bottom. It is used to "drill over" stuck pipe to free it before fishing.

- Spotting: This is used when jarring alone will not free the fish. Oil or special chemicals are spotted around the fish in an attempt to penetrate the wall cake, causing it to deteriorate and make the pipe slick. Spotting with water/oil when differentially stuck, and acid spotting when stuck in limestone are often used in an attempt to free the pipe.

- Safety Joint: This is a coarse-threaded joint which may be easily released. It is run above a fishing tool in case the fish cannot be freed and the fishing tool cannot be released.

If spotting and jarring do not free the fish, the "free point" is used to locate the stuck point and the upper portion of the drillpipe is "backed off". Fishing operations can then be carried out.

•Notes•

Formation Evaluation Techniques

Formation evaluation describes those techniques that are used during the life of a well to provide data on the hydrocarbon content, formation properties, and production capabilities. Some are performed during the drilling of the well, while others are performed after drilling is completed.

Surface Logging Systems

Surface Logging Systems (SLS) provides the client with engineering monitoring and data acquisition services, as well as the geological and hydrocarbon evaluation at the wellsite. This, together with pertinent correlation data, provides comprehensive information management with minimum cost and maximum safety. Since the cost of drilling operations is so immense that, on average, if the SLS can save the client just one day of time in an offshore rig, the cost of our services is justified for the whole well.

This wellsite service is conducted by professional geologists and engineers working in “logging units” (portable wellsite laboratories). The units are described in terms of the type of “shell” and the services performed, as illustrated in Figure 5-1.

The Logging Specialists

By employing graduate geologists and petroleum engineers, Baker Hughes INTEQ offers the highest possible level of formation evaluation service. Continuing research and development ensures that the SLS equipment and services continues to improve. Our reputation is earned by the person at the wellsite. Thus, it is essential that our field personnel always represent the company to the best of their abilities.

Major Responsibilities

Stated simply, the SLS geologists and engineers are one of Baker Hughes INTEQ's professional wellsite representative in the areas of:

- Technology - recording the geological and engineering data obtained while drilling
- Evaluation - interpretation of the acquired data

- Communications - informing the client in a timely manner of significant changes in the well, by means of immediate verbal communication and by standard written reports

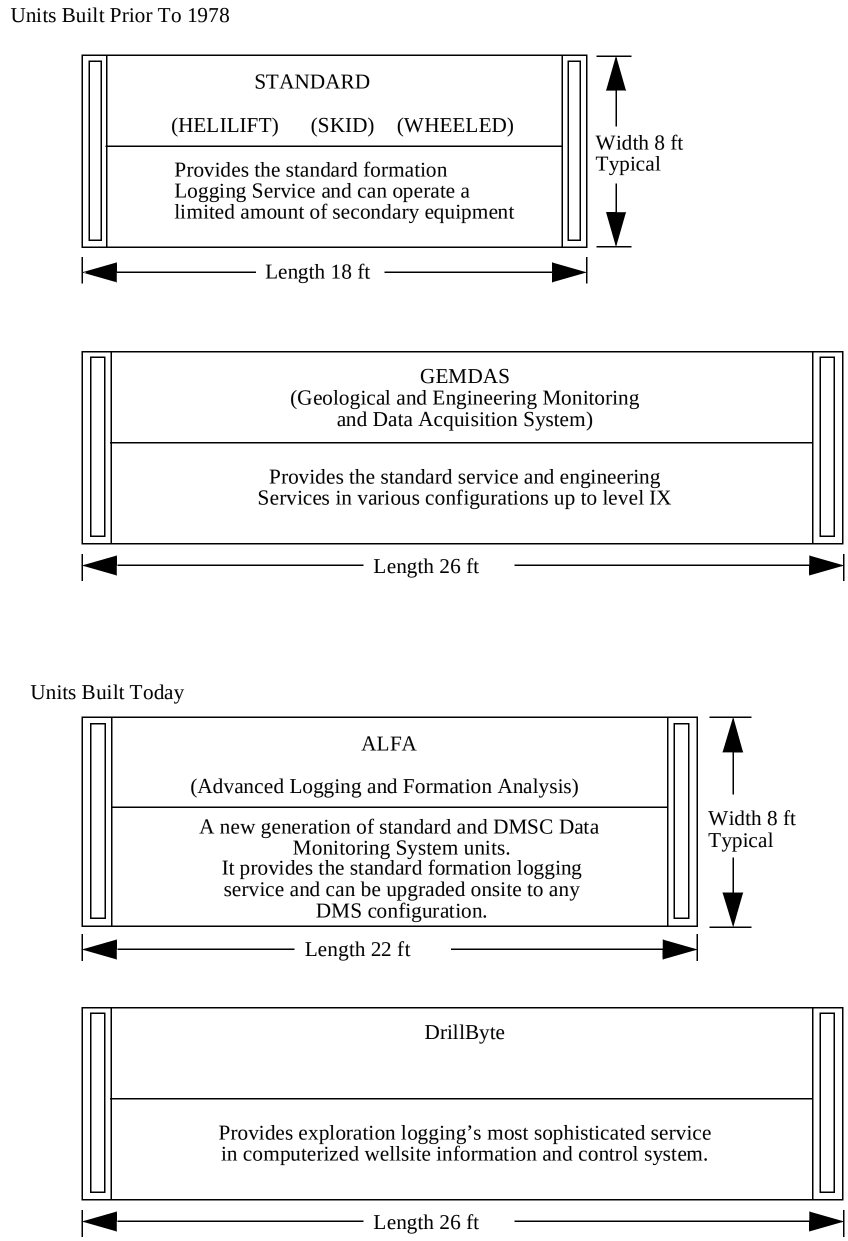


Figure 5-1: Types of Logging Units and Their Services

Coring

Coring provides additional formation samples for analysis. Two basic methods of collecting the samples are:

- Bottomhole Coring
- Sidewall Coring

Bottomhole coring, generally called conventional coring, obtains a cylinder (3 to 5 inches) of relatively undisturbed formation during the drilling of a well. The lengths vary (30 to 90 feet), and the decision to “cut a core” involves both geological and engineering considerations. Baker Hughes INTEQ is an industry leader in bottom-hole coring techniques and services.

Sidewall coring obtains a small (1 inch by 3 inches) interval of formation after the drilling process. Since this may take place several weeks after drilling the formation, contamination and formation damage can take place, making the sample of relatively inferior quality. They are obtained quickly, though and can cover more of a depth range than bottomhole coring.

Wireline Logging

After each section of the hole is drilled and before casing is run into the hole, it is necessary to “log” the hole. This involves running one or more wireline logging tools, either singly or in combinations.

The procedure for wireline logging is shown in Figure 5-2. The sonde contains one or more measuring devices and a cartridge which contains electronic control and transmission circuitry. It is lowered into the hole by an armored, steel cable. This cable contains seven separate conductors within its core which transmit power and signals between the surface and the tool. The sonde is usually 3-5/8 inches in diameter and may be up to several feet long.

After reaching bottom, wireline logs are run by pulling the sonde and cartridge up the hole at a fixed speed which is determined by the type of measurement to be made. As the tool is withdrawn from the hole, a continuous measurement signal is sent to the surface (via electrical conductors in the cable) where the raw data is processed in a control panel and recorded in the proper log format on film by an optical recorder.

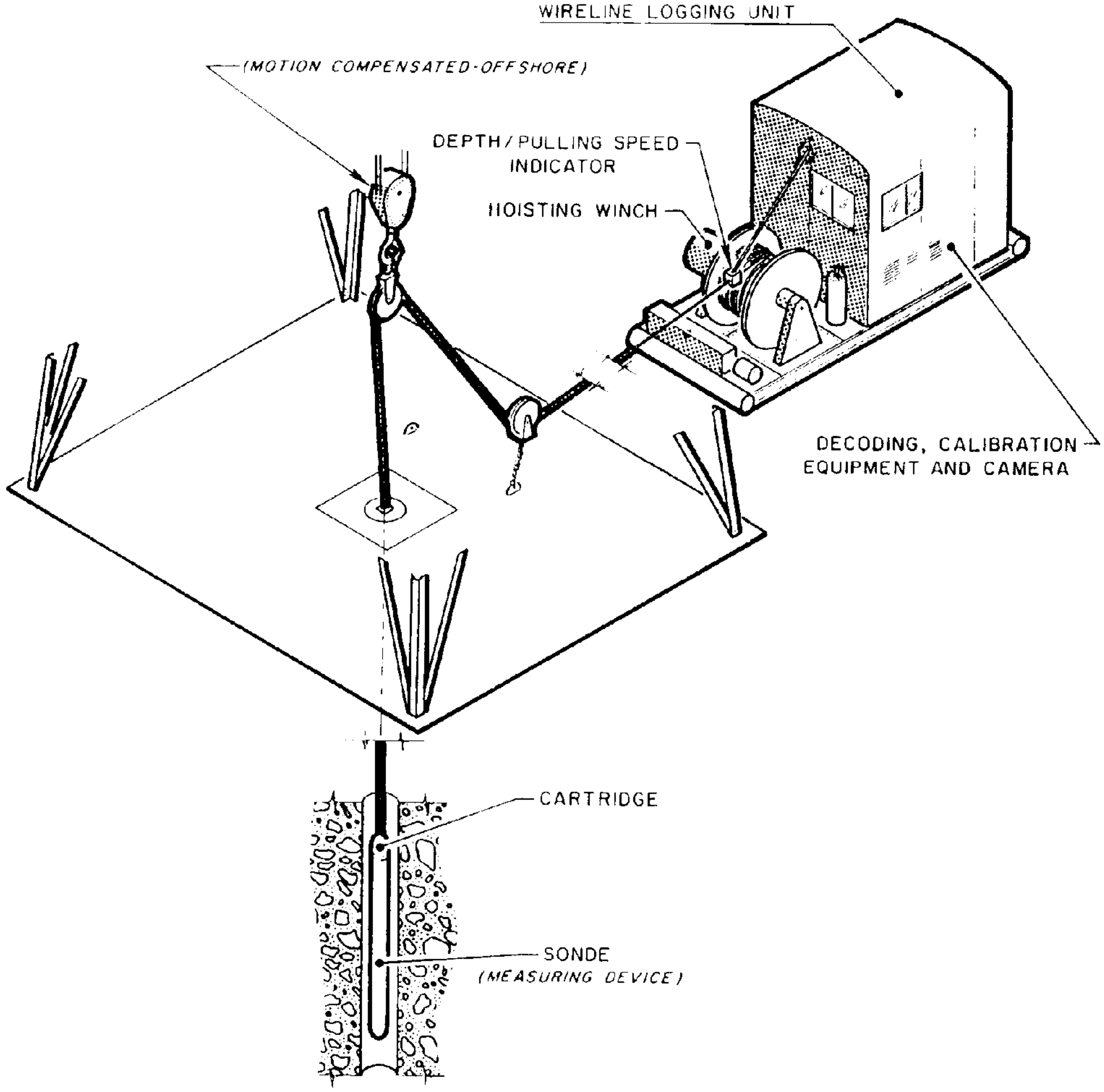


Figure 5-2: Wireline Logging Operations

These signals may also be recorded by digital tape which allows computer processing of all logs, either at the wellsite or in a critically located computing center.

Enhancements in INTEQ's Surface Logging Systems allows this wireline data to be imported into their wellsite computers, thereby providing composite log output at the wellsite.

Wireline logs and their information are used for:

- Correlation Purposes
- Bed Thickness Determination
- Porosity
- Water Saturation

These measurements enable conclusions to be drawn on:

- Lithology
- Permeability
- Presence and Type of Hydrocarbons
- Mobility of Hydrocarbons

Measurement While Drilling

One of the major drawbacks of wireline information is that it is received several hours to several weeks after the borehole is drilled. During this time period the formation adjacent to the borehole can undergo significant alteration, especially in its fluid saturation, effective porosity, and relative permeability. Measurement While Drilling (MWD) services allow wireline-type information to be available as near real-time as possible.

Another vital element in MWD services is directional survey measurements. As discussed in Chapter 4, surveys are necessary on all wells to; 1) ensure the well intersects the target, 2) prevent doglegs, and 3) for legal requirements. MWD allows surveys to be taken at every connection, eliminating the costly down-time of the earlier survey methods.

Baker Hughes INTEQ provides two MWD systems; probe-based and collar-based. Though both provide directional survey measurements, probe based tools are generally used in slimhole and short radius applications, while the collar-based systems provide a full range of formation evaluation (FEMWD) services.

A recent application of MWD services is “geosteering”. This horizontal drilling application utilizes resistivity measurements to identify bed boundaries and fluid changes. This allows the drillstring to remain within the reservoir or to return to the reservoir whenever the bit exits the formation. It also recognizes when the drillstring enters the water leg of the reservoir.

Formation Tests

Formation testing is a means of obtaining information concerning the liquid and pressures in a open-hole formations. One method of achieving this is by way of a temporary completion with a drillstem test (DST).

Drillstem Testing

A drillstem test is made by lowering a valve, a packer, and a length of perforated tailpipe on the end of the drillpipe to the level of the formation. The packer set against the wall of the borehole so that it seals off the test interval from the mud column above. The valve is then opened. This procedure effectively reduces the pressure opposite the formation to atmospheric pressure, and the formation fluids can flow into the hole and be produced through the drillpipe. It amounts to a temporary completion of the well, and the produced fluids are therefore representative of the fluid production that may be expected if the well is eventually completed.

Wireline Formation Testing

Three different types of testers are available to provide testing for almost every type of hole condition. Wireline testing is faster and safer than drillstem tests because pressure data is recorded at the surface and the full fluid column remains in the hole.

- Repeat Formation Tester - for any number of formation pressure tests and two fluid samples.
- Formation Interval Tester - for single tests in open or cased hole.
- Multiple Fluid Sampler Tool - for multiple tests in open or cased hole, this tool is essentially a number of Formation Interval Tester tools linked one above the other.

Wireline formation testing tools are run with either an SP tool or a Gamma Ray tool to provide correlation, or in cased hole they may be run with a casing collar locator (CCL).

When these tools are run in open hole, care should be taken to seat the tool in an area where there is a smooth response on the caliper log.

Repeat Formation Tester

The repeat formation tester, illustrated in Figure 5-3, is run into the hole and a continuous digital readout of hydrostatic pressure is obtained. At any point in the open hole, the tool may be hydraulically actuated to force a rubber pad against the wall of the hole, and a tube in the center of the pad is forced hard against the formation. As the tool is actuated, a low pressure area is created in a chamber behind the central tube and an extension of the tube against the formation connects this chamber with formation pressure. Thus, a readout of formation pressure can be obtained a number of times, and at anytime two chambers in the tool may be filled from the tube forced against the formation. Both the small area of this tool in contact with the formation and the positive hydraulic retraction reduce the possibility of differential sticking.

Formation Interval Tester

After positioning the tool in the hole, the tool is hydraulically actuated (a rubber pad (or pads) tightly against the formation to form a seal against the hydrostatic pressure of the fluid in the hole). A shaped charge (or charges) is then fired into the formation, opening a passageway for formation fluids to flow into a chamber in the tool. A surface readout of pressure enables the monitoring of the sampling, shut-in and hydrostatic pressures. After the sample chamber is sealed and a shut-in pressure has been obtained,

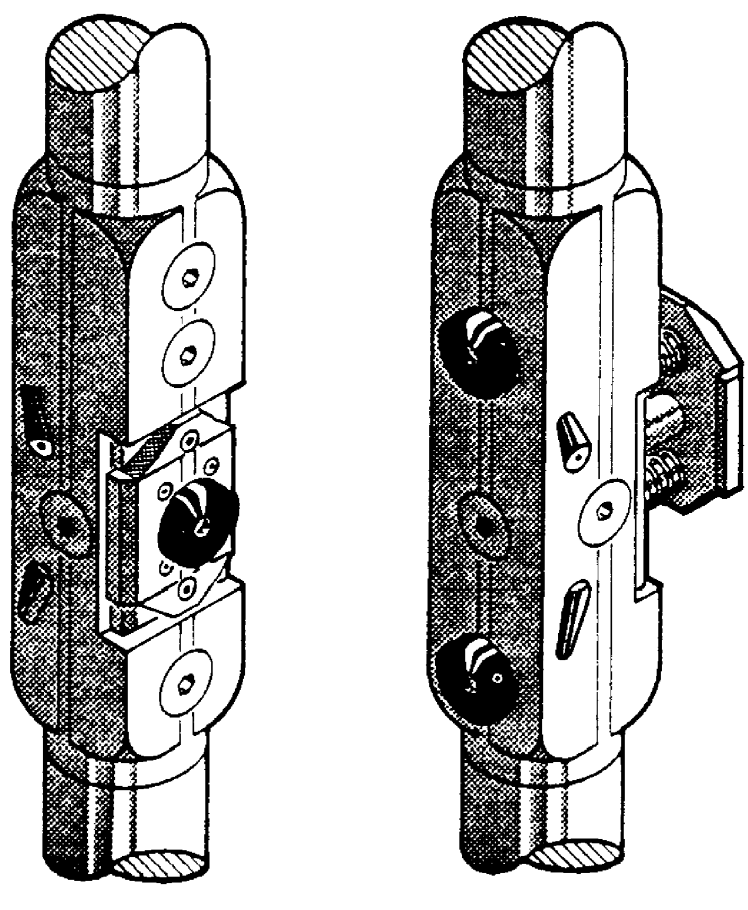


Figure 5-3: Repeat Formation Tester

the tool may be retracted and returned to the surface. If the tools are used in cased hole, it is possible to provide a chamber containing four gallons of cement which may be injected into the perforations through the casing prior to retracting the tool.

Testing through casing reduces the possibility of sticking this type of testing tool and increases the likelihood of obtaining a successful test. If the tests are made after casing has been set, and with a good cement bond behind the casing, the effect of invasion is reduced and interpretation of the recovered fluids is easier.

Evaluation of Recovered Sample

When the tool is recovered at the surface, the chamber pressure is reviewed; (l) as a check against the value for formation pressure obtained downhole and (2) to indicate any leaks in the sample chamber valves. The chamber is then discharged through a simple separator and any gas is passed through a positive displacement flowmeter. The liquids recovered are separated into oil and water, and the resistivity of the water will be recorded. If a nitrate tracer was run in the mud system, a nitrate ion test can be run on any recovered water. If the sample contained oil or gas, the oil gravity and gas analysis may be obtained and the ratios of gas, oil, formation water, and mud filtrate enable an empirical estimate of the quantity and quality of fluids that may be produced from the interval tested.

Chapter 6

Well Completions

The drilling of a well is only the first stage in the total life of that well. Following the drilling, the well must be “completed” in order to produce hydrocarbons at a commercial rate. When we take a close look at the drilling processes, we can understand why completions are so important.

As discussed in the previous chapters, when a well is drilled the formation is first crushed by the drill bit, then invaded by the drilling fluid. After drilling, the formation is surrounded by steel casing and weighted cement is pumped into the casing/formation annulus to bond the casing to the formation. After all of this, the target formation will need a little help if it is expected to produce hydrocarbons.

To reduce the effects of the drilling process, specialized services are called upon to prepare the formation for production.

Formation Damage

Even though all attempts are made to keep formation damage to a minimum, the drilling, completion, and production processes can cause extensive (and expensive) damage to those formations expected to produce oil and gas.

Damage to a formation, which prevents or reduces its production capacity, results in two changes within the formation; 1) reduction of pore size (volume reduction) and 2) reduction in relative permeability (flow reduction).

Volume Reduction

The pore space (pore volume) within a formation can be reduced two ways:

- Filling the pores with another material -which can be caused by:
    - Solids invasion (Drilling or Completion Fluids)
    - Fluids invasion (Drilling of Completion Fluids)
    - Cement invasion
    - Native clay hydration
    - Mineral/Paraffin precipitation
    - Perforation debris

- Compaction of the formation - which can be caused by:
  - Production of reservoir fluids
  - Proppant destruction in hydraulic fractures

Flow Reduction

Relative permeability is the permeability of one fluid (oil or gas) in the presence of another fluid (formation water or gas). It can be reduced by:

- Fluid Interactions
  - Formation of a brine/crude emulsion
  - Increase in formation water content (water coning)
  - Invasion of wellbore fluids
- Pressure/Temperature Changes
  - Gas breakout caused by reduction in pressure
  - Water coning
  - Fluid Saturation changes

Most permeability related changes occur after the well is producing hydrocarbons.

Completion Practices

Because many of the earlier wells were drilled until the well had a “blowout”, completion practices generally meant waiting until the “gusher” stopped. The well was then capped, and it then went “on-line”.

Such “barefoot” completion procedures are wasteful, detrimental to the life of the well, and therefore are seldom used today. Most wells are now cased, cemented and perforated to allow more controlled and sustained production.

Long term well planning, in-depth reservoir engineering, and development geology are the keys for ensuring maximum hydrocarbon production over the expected life of the well.

Types of Completions

The initial step in determining what type of completion is required is based on the well design. “How will the well be drilled?” is the first question to be answered. As mentioned in Chapter 4, the three ways a well can be drilled include:

Table 6-1: Well Design Options

Type of Well	Reasons to Drill and Complete
Vertical	Easiest and cheapest to drill Simple to operate Best type of well for hydraulic fracturing Best type of well for thick, homogeneous reservoirs
Directional	More difficult to drill Can effectively produce from several targets Can reduce the number of well required for a field
Horizontal	Difficult to drill and complete Effectively produce from thin reservoirs Minimize gas and water coning Minimize wells required for a field Effectively produce fractured reservoirs

Once the type of well to be drilled has been decided upon, it is time to determine which the type of completion will satisfy the production requirements for that particular well.

There are many variations on the three types of completions listed below (Figure 6-1), and each well is different. Regardless of the type, completion requirements for the well must be determined early on in the planning process, because the type will dictate tubing and packer requirements, completion and simulation practices (perforating, sand control, hydraulic fracturing, acidizing, etc.) and the type of lift necessary to bring the hydrocarbons to the surface.

Barefoot Completions

Barefoot completions are essentially open hole completions. Casing is set just above the reservoir and production tubing is run into the casing. Hydrocarbons are then produced directly into the bore hole, which flow into the tubing and then to the surface.

This type of completion has two important advantages; 1) it is cheap and simple to operate, and 2) hydrocarbons will flow into the bore hole throughout its 360^o circumference (radial flow).

However, several drawbacks are readily apparent:

- Hydrocarbons must pass through the damaged portion of the bore hole wall, which includes any filter cake
- As the hydrocarbons are produced, the formation (and bore hole) must be able to withstand the loss of fluids and be strong enough not to collapse.
- If the open hole extends past the reservoir, it is impossible to isolate flow from just the reservoir. Unwanted fluids (gas or water) can be produced from other formations or from the same formation (if the oil/water contact is exposed).

If well stimulation or workover is necessary, expensive isolation procedures will be required.

Uncemented Liner Completions

Placing an uncemented liner across the reservoir is the next least expensive completion type. Casing is run to the top of the reservoir, then a slotted liner is hung off the casing through the reservoir. The liner is not cemented. This type of completion is attractive in directional wells.

Advantages over barefoot completions are apparent:

- The slots/holes in the liner are necessary only through the reservoir/producing zone.
- The liner will help prevent hole collapse
- The slots provide some sand control
- Production through 360^o is still achieved

As with barefoot completions, all fluid flow must take place through the formation adjacent to the bore hole. If that part of the hole is damaged or if filter cake is present, production will be reduced.

Cased, Cemented and Perforated Completions

It is obvious that a bore hole which is cased, cemented, and perforated will be more expensive than the previous two. However, because of its ability to effectively isolate the producing zone and by-pass the damaged portion of the bore hole, this type of completion is the most common.

Either casing or liner is run across the reservoir and cemented into place, providing excellent hole protection. Production tubing is run in the casing as close as possible to the reservoir and the reservoir section isolated using packers. The casing/liner across the reservoir section is then perforated (by-passing the filter cake and damaged zone), allowing production of the hydrocarbons.

However, besides being the most expensive completion practice, this type of completion also has its drawbacks. When perforating:

- It is necessary to by-pass the damaged zone, which may or may not be possible
- Based on the perforation spacing, the well may not achieve 360^{o} coverage
- The permeability within the perforations will be reduced if debris fills the openings

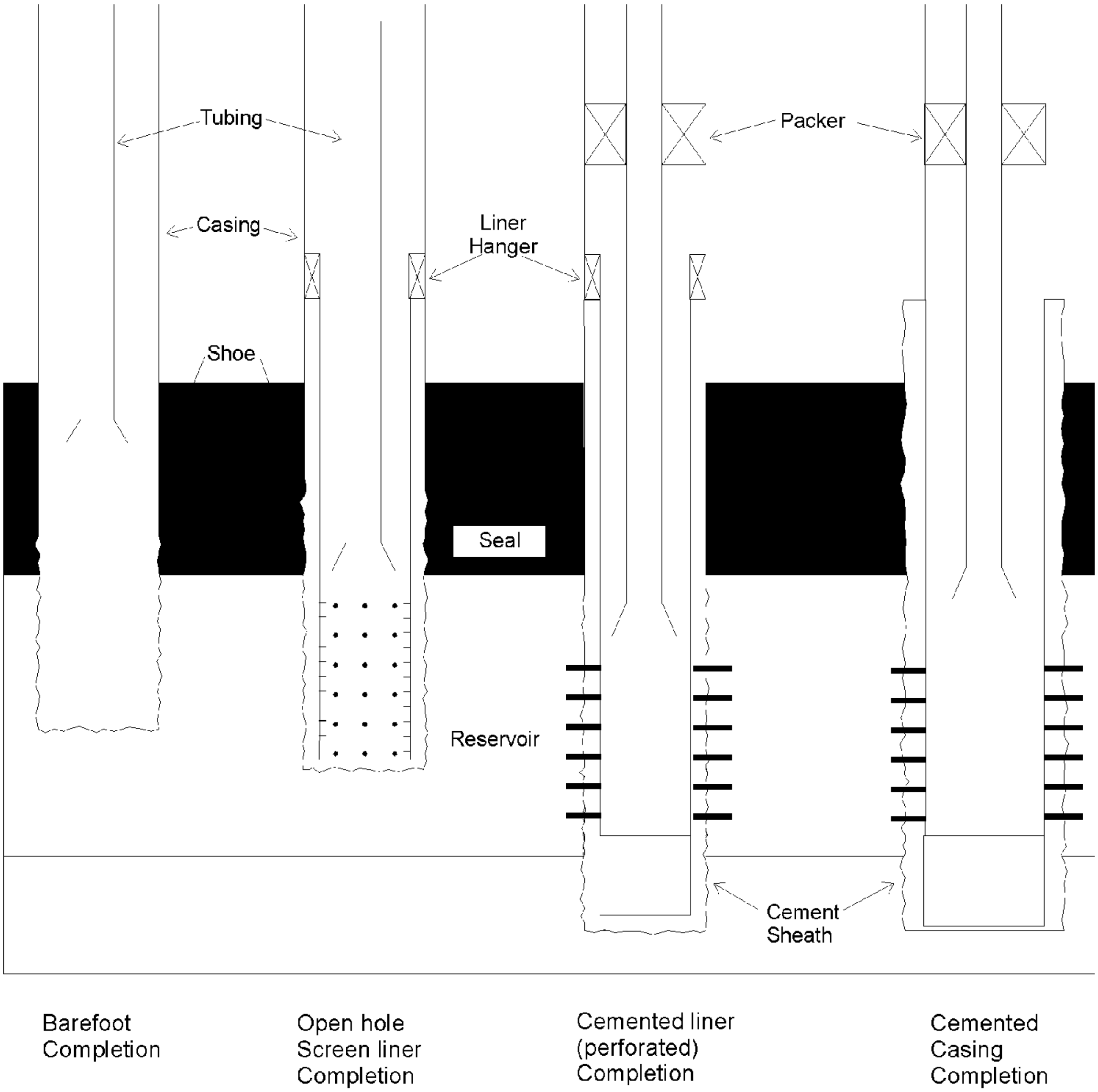


Figure 6-1: Types of Completions

Perforating

As mentioned earlier, wells today are generally cased and cemented, so in order to allow the well to produce hydrocarbons, openings must be made through the casing and cement. These openings (or perforations) are created using explosive bullets, known as “shaped charges” (Figure 6-2), using the same principle as the military’s armor piercing rounds.

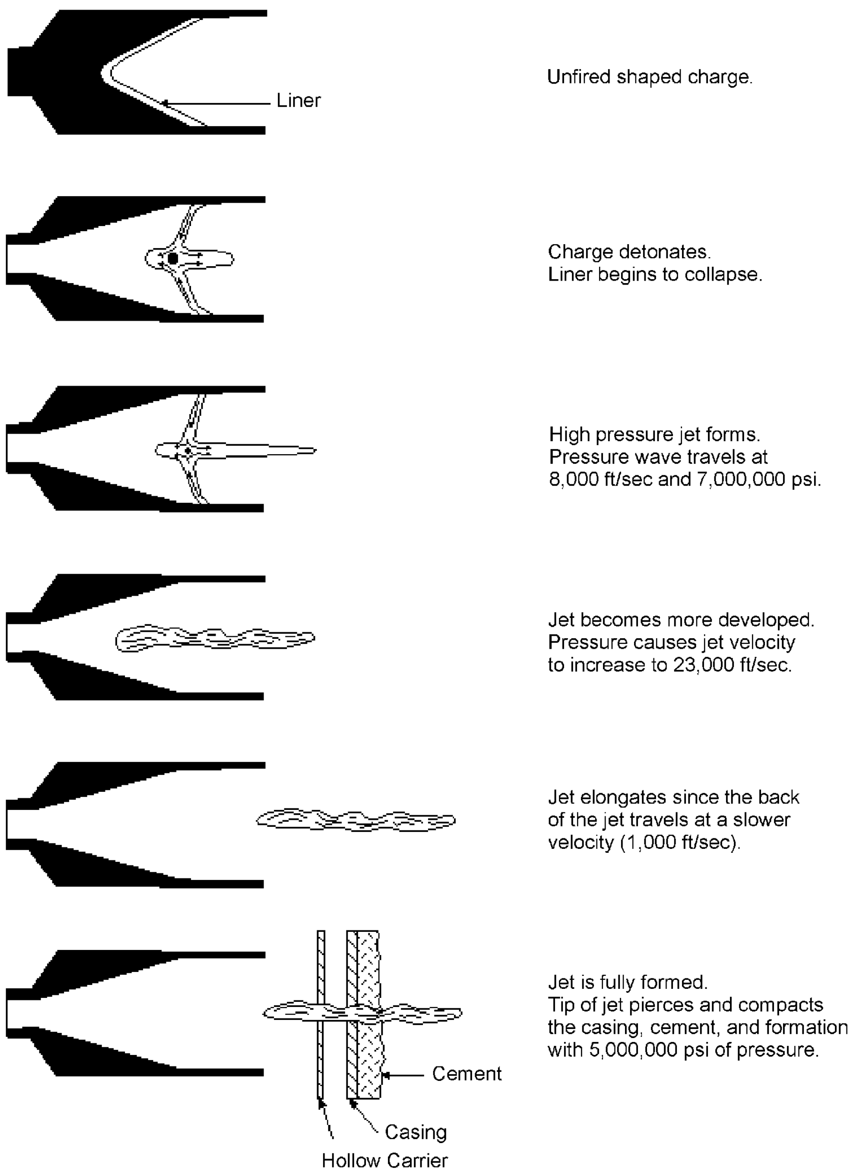


Figure 6-2: Stages of a shaped charge during perforating

The guns containing the shaped charges can be run into the well using wireline, coiled tubing, drillpipe or tubing. Baker Hughes INTEQ is a major supplier of Tubing Conveyed Perforating (TCP) Systems.

Operations

When the decision is made to perforate, several questions need to be answered to ensure maximum flow efficiency from the perforated zone. Some of those questions are; shot density, phase angle, penetration length, and penetration diameter.

Shot Density

Computer programs are used to determine the number of shots per foot (spf) or shots per meter (spm) required for the reservoir (using the anticipated production rate of the well). Regardless of the number of shots, the clean up efficiency must be kept in mind.

Phase Angle

The phase angle or “phasing” (Figure 6-3) is the direction in which the shaped charges are fired relative to the other shots in the gun. Common phase angles are 45^o, 60^o, 90^o and 120^o. This phasing becomes very important when perforating horizontal boreholes where you want to perforate only the low side of the hole or where there are other tubing strings in the well and the perforations have to be performed around the other completion strings.

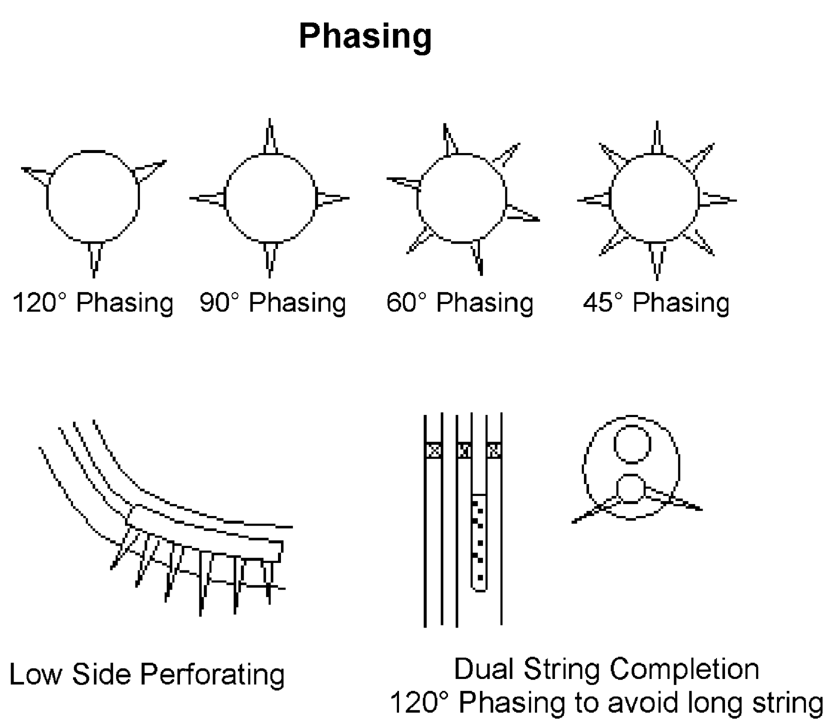


Figure 6-3: Phase angles for perforating guns

Penetration Length

The actual depth of penetration has a great effect on production performance, therefore it is usually necessary to obtain the greatest penetration possible. The length of the perforation is difficult to determine, and tunnel length is generally provided by the manufactures, based on gum size, test material (i.e. concrete or sandstone, etc.) and shot type (i.e Gravel Pack Charge or Deep Penetrating Charge). Generally, the deep penetration charge (Figure 6-4) will give a tunnel between 1 and 2 feet in length, while the gravel pack shot will only be about 8 inches in length.

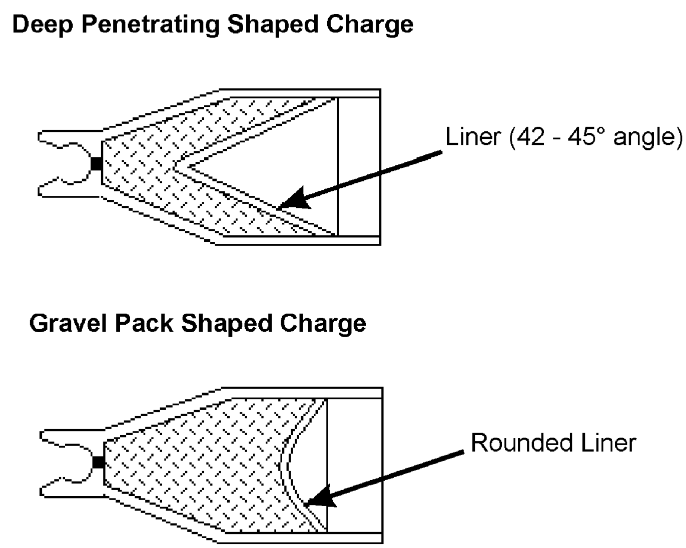


Figure 6-4: Charge types for various depth and diameter applications

Penetration Diameter

Gravel pack charges (Figure 6-4) produce large diameter holes (around 1-inch), while the deep penetrating charges will produce an opening between 0.5 and 0.75 inches in diameter.

Clean-Up

Once the jet pierces the casing and cement, the portion of formation immediately surrounding the blast will be compacted and filled with debris (Figure 6-5). This material must be removed in order for production to be restored to its maximum capacity.

The formation (generally quartz) and cementing agents (generally calcite or quartz) are crystalline in nature, and will tend to form an impermeable sheath around the circumference of the blast zone. In addition, the blast tends to create debris within the perforation. The debris can be pieces of the formation and cement, metal from the casing and shaped charge housing, and pieces of the shaped charge itself.

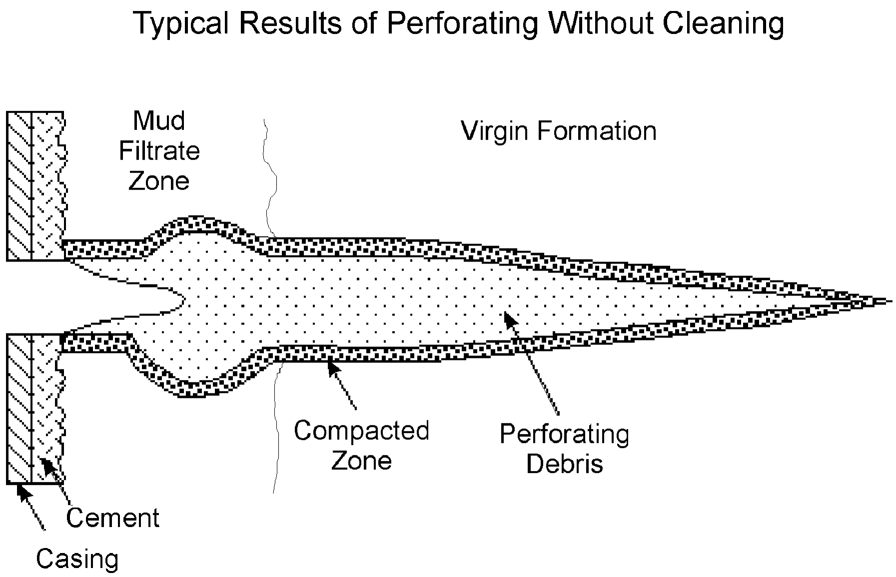


Figure 6-5: Perforated zone without cleaning

The crushed material and compacted zone can be removed by immediately placing the formation in an under balanced situation, which allows the debris material to be flushed into the well bore and removed at the surface. If the formation contains sufficient carbonate material, it can be acidized. However, quartz and metal require powerful acids to dissolve them.

Once the perforations are cleaned, they must remain open (not be plugged) or filled with a material that is both porous and permeable (packed with sand). This will allow the flow of hydrocarbons through the perforations and into the borehole.

Sand Control

During hydrocarbon production from unconsolidated sand resevoirs, there is a tendency for the sands to compact after the pore fluids are removed. When the reservoir fluids are produced, pressure differential and frictional drag forces are created which can exceed this compaction matrix strength, and a significant amount of the sand can be “produced” (i.e. flow into the borehole and production tubing). This sand production is very detrimental to the well causing:

- erosion of downhole and surface equipment
- filling up surface separators and storage tanks
- sand-laden fluids
- increased costs for sand disposal

Sand production is typically a problem when producing hydrocarbons from shallow, geologically young (Tertiary) formations.

The service of mechanically controlling the amount of sand production is known as “Gravel Packing”. Baker Hughes INTEQ is a leading supplier of gravel pack equipment and services.

Types of Gravel Packs

A gravel pack involves placing a screen in the borehole, then filling the annular space between the screen and casing (and perforations when present) with a specially sized, highly permeable sand (Table 6-2). The formation sand bridges on the gravel pack sand and the gravel pack sand bridges on the screen. This two-stage filter allows sand-free hydrocarbon production.

Table 6-2: Sand Size Ranges and Screen Openings

Sand Size (US Mesh)	Opening Sand Passes Through (inch)	Opening Sand is Stopped By (inch)
8 - 12	0.094	0.066
12 - 20	0.066	0.033
20 - 40	0.033	0.017
40 - 60	0.017	0.0098
50 - 70	0.012	0.0083

The gravel pack sands used within the oil industry should conform to the industry’s accepted standards found in API RP 58 “Recommended Practices for Testing Sand Used in Gravel Packing Operations”.

Pre-Packed Screens

These are very useful in open-hole completions, in horizontal well completions, and in cased hole completions where sloughing sand is a problem.

The pre-packed screen contains a layer of resin-coated sand/gravel between two screens. This additional layer of sand acts as another bridging agent should the screen jacket fail.

After the screens are run into the hole, the well is gravel packed in the usual manner.

Frac Packs

This is a recent development for completions, where cased hole gravel pack and hydraulic fracturing are combined to give increased productivity than when using those completion techniques separately.

The objective of frac packs is to place the gravel past the near-wellbore damaged zone and are generally required where there is deep formation damage, a perforated interval is highly laminated, or where a formation’s permeability is so high that its fracture pressure cannot be exceeded by injecting a brine alone.

Once the zone is hydraulically fractured, the gravel is used at the proppant and this is followed by inserting a gravel pack screen into the wellbore.

Gravel Pack Operations

When gravel pack screens are run into the wellbore, they must be run in with great care to ensure the screens are kept clean and to minimize damage to those screens.

Also when the gravel is placed into the formation/wellbore, it must be kept clean, it must be tightly packed, and it must not cause damage to the formation. This generally means ensuring the correct gravel size, the best carrier fluid and optimum placement technique. It has been shown that as little as 0.5% fines in the gravel can significantly reduce permeability and therefore production.

Gravel packing will also stabilize any formation damage. It is therefore necessary to remove as much damage (filter cake, filtrate, perforation debris) as possible before beginning the gravel pack operations.

Well Stimulation

Well stimulation treatments were originally developed to rejuvenate old oil and gas wells by improving the porosity and permeability of the producing formations. As techniques have improved, however, they have been used more and more to initiate acceptable producing rates from new wells.

The first stimulation method, nitro-shooting, started about a hundred years ago to liven up wells that had almost ceased to produce. Sometimes the improvement after shooting was spectacular. Other techniques (acidizing for carbonate formations and hydraulic fracturing for sandstones) have almost completely taken the place of shooting, although it is still employed on a limited scale.

Acidization

In the early 1930s, acid stimulation for limestone and dolomite formations became commercially available within the oil service industry. The first treatments were with hydrochloric acid, though by 1940 mud acid (hydrofluoric and hydrochloric acids) mixtures were being used. Acidizing jobs are usually broken down into three categories:

- HCl pumped into carbonates to create new openings or channels (worm holes)
- HCl pumped into carbonates with borehole damage to create openings which by-pass the damaged portion
- Mud acid pumped into non-carbonates to dissolve and remove damaged portions or soluble clays

One of the most common methods of pumping acid into the well has been by bullheading. The major drawback of this method is that all the solids and fluids that have flowed into the well/tubing are forced back into the formation, which can cause more damage. A more effective method of pumping acid and introducing acid into formations is through the use of coiled tubing (CT).

Acid treatments can be used to clean the wellbore (acid washes), where the acid is pumped to the formation/perforations, then the pumping is stopped allowing the acid to enter the formation under hydrostatic pressure. These are usually short duration and when the well returns to production, the acid and by-products are removed at the surface. Another acid treatment is known as matrix acidizing, where the acid is used to dissolve away the formation to create new openings. The acid is pumped under pressure (below fracture pressure) into the formation, allowing the acid to dissolve near wellbore damage and create “worm holes” anywhere from several inches to several feet into the formation.

Acid Systems

The most common acid systems in use are:

- **Hydrochloric Acid**: This is the most widely used acid in treatments, with concentrations ranging between 7.5% and 28%, the most common is 15%. It will dissolves Calcium Carbonate ($CaCO_3$), Dolomite ($CaMgCO_3$), Siderite ($FeCO_3$), and Iron Oxide (Fe_2O_3).
- **Mud Acid**: This is a mixture of HCl and HF (hydrofluoric acid) and is generally 12% HCl and 3% HF. It will dissolve clay materials in the formation, along with feldspars and quartz. The HF will react with Na, K, Ca and Si in the clays to form insoluble precipitates, so it is advisable to always preflush with HCl.
- **Organic Acids**: These are Acetic and Formic Acids. They are slower acting than HCl, and are generally used in high temperature wells and wells with high alloy tubing to reduce corrosion rates.
- **EDTA**: This is Ethylene Diamine Tetra-Acetic Acid. It dissolves carbonates and sulphates by chelating them. It is more expensive than the other acids and the reaction is slower.

Acid Damage

Acidization can be very useful in increasing the productive life of a well, if done correctly. This means proper planning with site-designed operations. If operations are carried out incorrectly several damaging effects include:

- **Corrosion**: Acids will dissolve tubing and casing. This is generally minimized by adding corrosion inhibitors. However, since these inhibitors are not soluble in acids, they can potentially damage the formation.
- **Iron Precipitates**: Iron from the tubing/casing will dissolve when the acid is pumped. Once the pH of the spent acid rises, the iron will precipitate out in the formation. The best practice to reduce this problem is to “pickle” the tubing (pump HCl down the tubing, then reverse circulate the acid out).
- **Fluid Incompatibilities**: If the formation contains oil or an oil-based mud was used, the acid and oil can form an emulsion (which is accelerated by the dissolved iron). Surfactants can be used with the acid, but they also can react with formation fluids.
- **Fines Mobilization**: Acids will affect the clays in the formation. Mud acids will react with clays leaching out the aluminum ions, causing silica to fall out. In addition, the pH shock of acidizing can disperse clays throughout the formation, causing them to block pore throats

- **Cement Bond Destruction**: HCL and HF will dissolve cement and break it down, especially if channels in the cement exist.

Hydraulic Fracturing

In 1949, hydraulic fracturing was developed as a commercial oil field stimulation process. The procedure is to pump a viscous fluid down the well at rates and pressures to break down (fracture) the formation. The pressure is slowly increased while pumping a mixture of polymer gel and sand into the induced fractures to hold open the fissures after the hydraulic pressure had been released.

The fractures created in this way are generally planar, with openings between 0.25 to 0.5 inch (though the length may several hundred feet). As with any fracturing, the openings will propagate along the lines of least resistance, so the subsurface stresses (overburden, folding, faulting, inclined bedding) will determine whether the fracture is vertical, inclined or horizontal,. Hydraulic fracturing can be used in any competent formation (sandstones, limestones, dolomites, etc.) and should be avoided in soft and plastic formations.

Materials Used In Fracturing

The materials used in hydraulic fracturing includes the fluid causing the fracturing and the “proppant” used to hold the fractures open after the pressure has been released.

The most common fluids used today are water-based synthetic polymer gels (usually cross-linked gels) and hydrochloric acid. These fluids are very viscous which will both increase the fracture width and carry larger proppants. They are also more stable at higher temperatures, making them effective in deep wells.

Proppants are used to maintain fluid flow and permeability after the fracturing operation. Common propping agents are sand, sintered bauxite and plastic-coated sand. The six physical properties of the proppants that affect the fractures ability to conduct fluids are;

- Grain Strength
- Grain Size,
- Grain Size Distribution
- Grain Sphericity
- Quality (amount of impurities),
- Proppant Density.

Types of Fracturing

There are two types of fracturing treatments, generally based on the formation type. Acid fracturing for carbonate formation and proppant fracturing for sandstones.

In acid fracturing, hydrochloric acid is used, under pressure, to dissolve enough formation creating large fractures which will remain open after the pressure has been released. In some situations, proppants may be necessary.

Proppant fracturing is required for sandstones and those formations where openings cannot be etched by acid. In this operation, a clear frac fluid is pumped to initiate the fracture. The proppant slurry is then pumped into the fracture to fill the openings and to extend the fracture.

When the pressure is released, some of the proppants will become embedded in the formation, some may be crushed, while the remainder will allow the fracture to remain open (Figure 6-6).

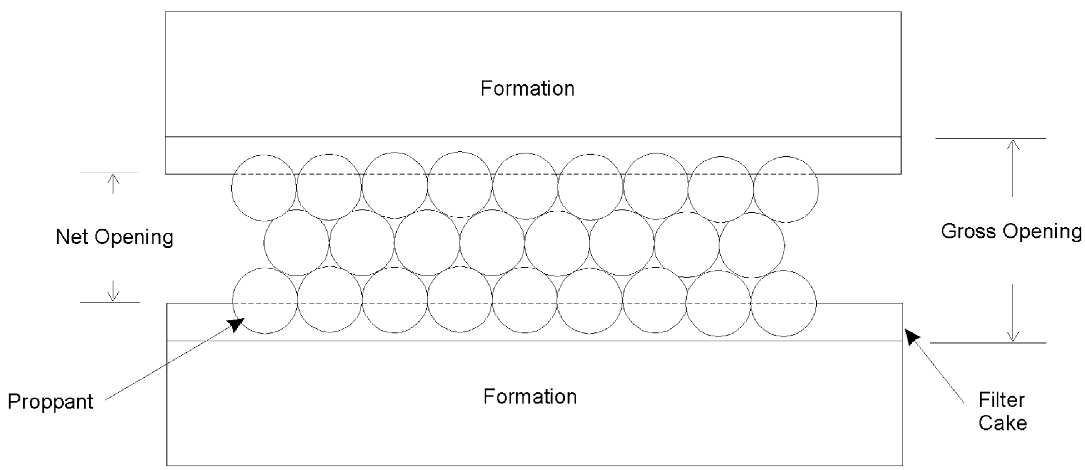


Figure 6-6: Fracture opening after hydraulic fracturing

Fracture treatments are expensive, but the method is frequently employed. The process does for tight sandstone reservoirs what acid treatments do for limestone or dolomite reservoirs. Many wells that would not have otherwise justified their costs have done so with fracture treatments.

Completion Efficiency

Regardless of the type of well completion, the primary aim is to make the wellbore as efficient as possible in producing hydrocarbons. Such efficiency is always determined in terms of costs and cost savings (i.e. production rates, longevity, and workover).

When looking at the two main types of completions (cased hole or open hole), it is always best to remember that the reservoir will dictate the maximum production rate, at its present state of depletion. Though mentioned earlier in the chapter, it is prudent to recall the many factors that can reduce the “maximum” production rate:

- Drilling and Completion formation damage
- Tubulars used for completion
- Surface production facilities
- Precipitates from reservoir fluids
- Phase changes in the reservoir fluids
- Changing fluid contacts
- Fines production
- Formation compaction

These will dictate production rates and such “damage” begins as soon as the drill bit enters the formation and continues until all hydrocarbons that can be produced, are produced.

Using these parameters to rate completion efficiency, in order to answer the question “Which type of completion is more efficient?”, we must try to reduce/minimize as many as those “chokes on production” as possible.

The answer to the above question generally points to an open hole completion, since:

- Open hole completions tend to exhibit less damage
- Open hole completions cost less
- Open holes have higher productivity and last longer

Therefore, the first option should be an open hole completion, especially if the following are true:

7. A continuous, single phase hydrocarbon flow is anticipated
8. High gas/oil or water/oil ratios can be tolerated

9. The reservoir is a single, uniform lithology
10. The reservoir can be drilled and completed while maintaining its stability

If any of the above are not true, then a cased hole completion will have to be recommended.

Again, the objective of a completed well is to produce the maximum amount of hydrocarbons as possible for the longest period of time, at the lowest cost. We must all strive to ensure this happens.

Regional Geology

This space in the Oil Field Familiarization Manual is provided for geological information which is supplied by the Business Unit. Regional/ Area geology is necessary so that the logging geologist will have the geologic information necessary to perform their duties to the standards set by Baker Hughes INTEQ.

•Notes•

Current Literature

This space in the Oil Field Familiarization Manual is provided for insertion of various literature that is relevant to formation evaluation techniques and procedures, and current company information. This information will be supplied by the Technology Sections of the local Business Unit.

•Notes•

Helicopter Safety

Many of the offshore drilling and production rigs are reach by helicopter. Though travel by helicopter is very safe, in the event of a "ditching" over water, there is a prescribed method of evacuation from the helicopter. All passengers must know these procedures.

The time is takes a helicopter in trouble to reach sea level from an average cruising height (1000 ft) is approximately 2 minutes, even under auto-gyro. With this in mind, it's no use trying to find the other half of the safety belt that you should have put on before take-off. Ditching in calm waters can result in severe shaking, and an unharnessed body can be thrown considerably. This results in injury to both the flying body and those hit by the flying body. Always buckle the safety belt when aboard the helicopter, prior to take-off.

In an emergency, there is the slight possibility that the helicopter pilot will contemplate ditching all excess cargo, and with the lighter craft, trying to reach the destination or, try and return to the point of departure. If not, ditching in the sea is the next alternative.

All handles that control the "jettison stage" are usually marked with yellow and black stripes, and are usually positioned near the doors and windows. Upon instruction from the pilot, all windows and doors should be jettisoned, which will open-up the escape routes from the helicopter (see Figure C-1). During this time the co-pilot, or an assigned passenger will arrange for an inflatable life raft to be placed outside the helicopter.

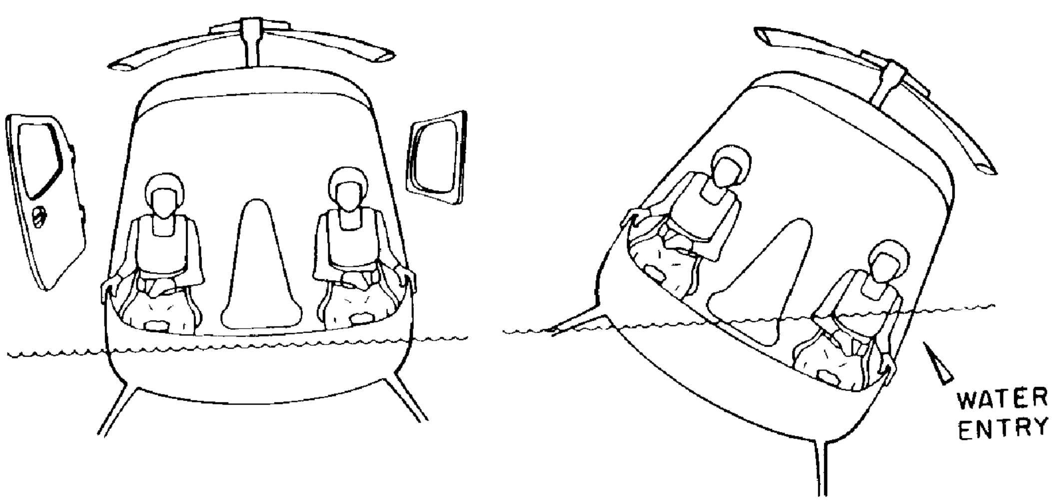


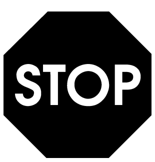
Figure C-1: Initial "ditch" of a helicopter

Having identified the most convenient exit, brace yourself for the splashdown. It is usual for only two or three people to use the same exit route. Point an arm as directly as possible to the nearest exit that you will use to let everyone know which exit they are to use, then hold onto something rigid (the back of the seat or an internal brace) and place the free hand on the safety belt release.

The sinking time for a helicopter is between one and ten minutes, depending on the state of the sea, design of the helicopter, floatation aids, weight distribution, and number of open hatchways. It is entirely possible that the helicopter will stay in an upright position. If this occurs, do not leave the helicopter until the rotor blades have stopped. A hasty exit could result in a wave crest carrying you into the “guillotine circle”.

Due to the poor weight distribution in a helicopter (engines on the roof), a helicopter will sink in a corkscrew, rolling action. When this occurs, the water will rush in and cause considerable turbulence inside the cabin. A force of 200 to 300 pounds of pressure will be forced onto your body. Do not try and exit at this time, because you will not be able to swim against this force. Continue to hold on during this time, if the safety belt is released you will be buffeted around the inside of the cabin.

As the water level is rising, try to control your breathing rate. As the water reaches your neck/chin level, take a normal breath and hold it.



WARNING!

Control the urge to release the safety belt. Without trying, the average person can hold their breath for 45 to 55 seconds. Panic will quarter this figure.

Once the main body of the helicopter is below the water and all major turbulence have ceased (this generally takes about ten seconds), the helicopter will tend to settle and sink slowly upside down in a nose down position (Figure C-2). Now is the time to release the safety belt and make for your designated exit. If you are in a gangway seat, allow those nearest the exit to leave first. This will prevent a “traffic jam” at the exit points.

A feeling of disorientation during this time is normal. Remain calm and use logic to overcome this panic-inducing sensation. Retrace your “pointing arm” motion, and with the free hand pull yourself towards the exit. Your lungs will be full of air, so you will be reasonably buoyant, and when outside the helicopter, you will begin to rise to the surface and regain your sense of orientation.

At this time, and not before, inflate the life jacket. It will assist you in the ascent to the surface. If you inflate the life jacket inside the helicopter, you will be too large to escape through the exit. In addition, you will immediately become buoyant and rise into a corner of the helicopter, making progress down the helicopter virtually impossible.

The life jacket should have been fitted correctly prior to take-off. This simple procedure can mean the difference between life and death.

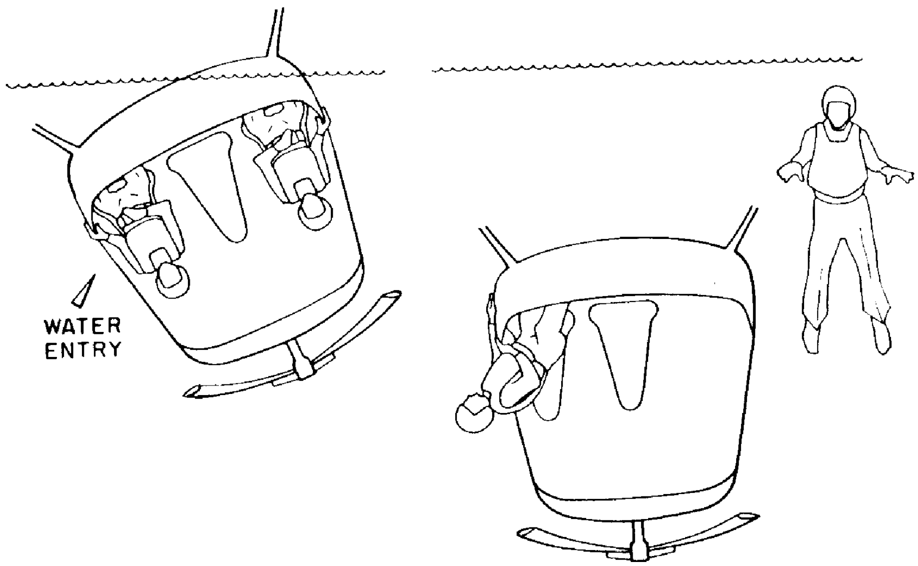


Figure C-2: Helicopter Submergence

If a life-raft has been jettisoned prior to ditching, work your way towards it. If ditching take place in cold seas, remember the principles of body-heat conservation.

Though this procedure may seem long and complicated, it is not. As a recap, the procedure is illustrated in Figure C-3.

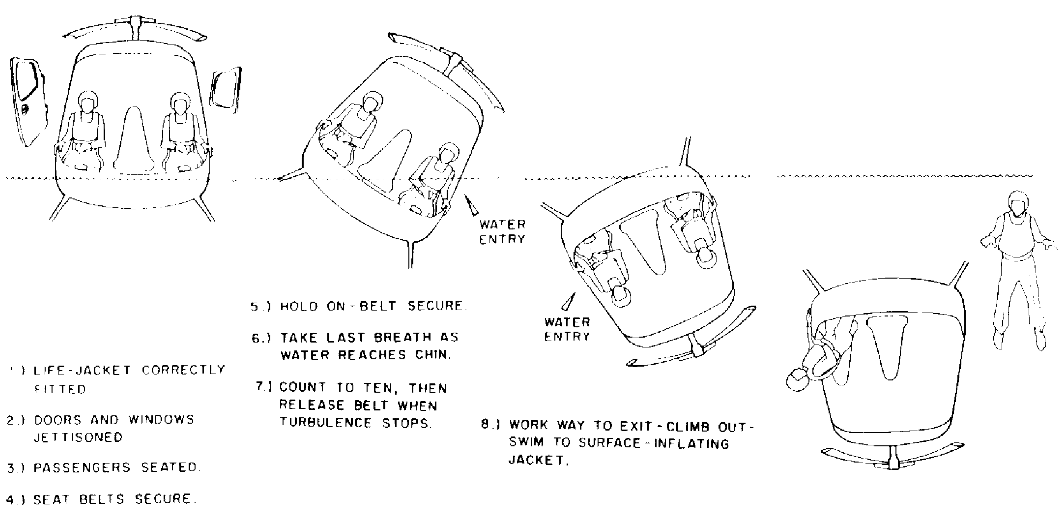


Figure C-3: Sequence of Events After Splashdown

•Notes•

Restricted Articles

At various times during your travel to the wellsite, it may be necessary for you to take or ship “restricted articles” to or from the wellsite. According to the International Airline Transportation Association (IATA), a restricted article is any material which can cause dangerous evolution of heat, gas, or radiation, or can produce corrosive materials under conditions normally incident to transportation. The following is a quote from the IATA regulations:

“No aspect in air transportation is more important than safety. The basic principle of **SAFETY FIRST** is as vital in the carriage of air freight as it is in other phases of air transport. Therefore, it is essential that all persons shipping or accepting air freight consignments are fully familiar with the detailed provisions set forth in the IATA Restricted Articles Regulations, and that the current edition is used. Any comments or suggestions for improvements are kindly invited.”

Restricted articles usually fall into one of the following categories”

- Corrosive Materials
- Compressed Gases
- Explosives
- Flammable Liquids
- Irritants
- Oxidizing Materials
- Radioactive Substances
- Combustible Liquids
- Etiologic Agents
- Flammable Gases
- Flammable Solids
- Magnetized Materials
- Poisons

If you are ever in doubt about an item's statue, contact the nearest Baker Hughes INTEQ office, the local air freight agent who handles shipment for the company, or the airline cargo representative. It is better not to ship an item if you are in doubt as to the validity of packaging and documentation. Contact the local office for assistance.

Shipping Procedures

The following rules must be adhered to when preparing restricted articles for shipment. In most cases, this will be handled by the local Baker Hughes INTEQ Shipping Department. However, you may have to handle this yourself at the wellsite (therefore it is advisable to save any packing material and boxes of those items you receive from the office). These rulings are from IATA Restricted Articles Regulations (22nd edition, 1 July 1979). Remember, IATA rulings change, so stay in touch with your local office regarding any shipments.

1. Ensure that the commodity can actually be air-freighted, according to the most current Department of Transportation (in the U.S.A.) and IATA regulations. The client oil company can advise you and give you assistance with this.
2. Ensure that the Commercial Invoice (CI) accurately describes the packed contents.
3. Submit the required number of copies of the IATA Certification to the “Forwarder” of the airlines. All must be signed as originals. Keep a copy of all shipping documentation of file for ready reference.
4. Ensure that the contents are properly packaged. All containers after packing should be able to withstand a four-foot drop to concrete without damage.
5. Affix the appropriate “dangerous cargo” labels to the container or cylinder (Figure D-1). These labels are normally, and readily, available from your local office. Also, all agents can affix them for you, but you must request this service in writing or by telephone. No substitute or marked-up labels are acceptable.
6. All dangerous cargo must be air-freighted on a separate air waybill and Commercial Invoice (one item to one CI). This way, if one item is not acceptable, the shipment of the other items will not be delayed.

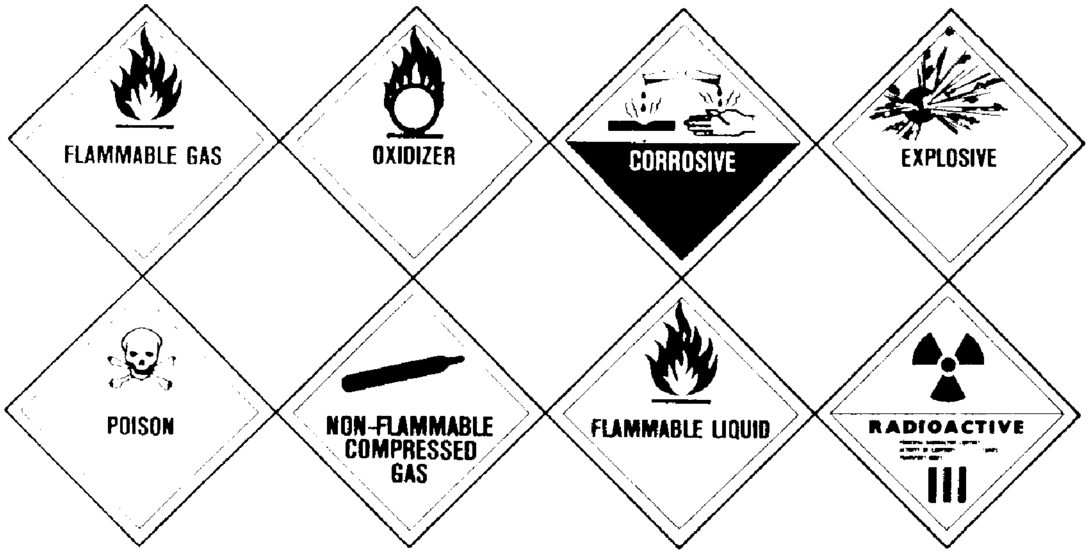
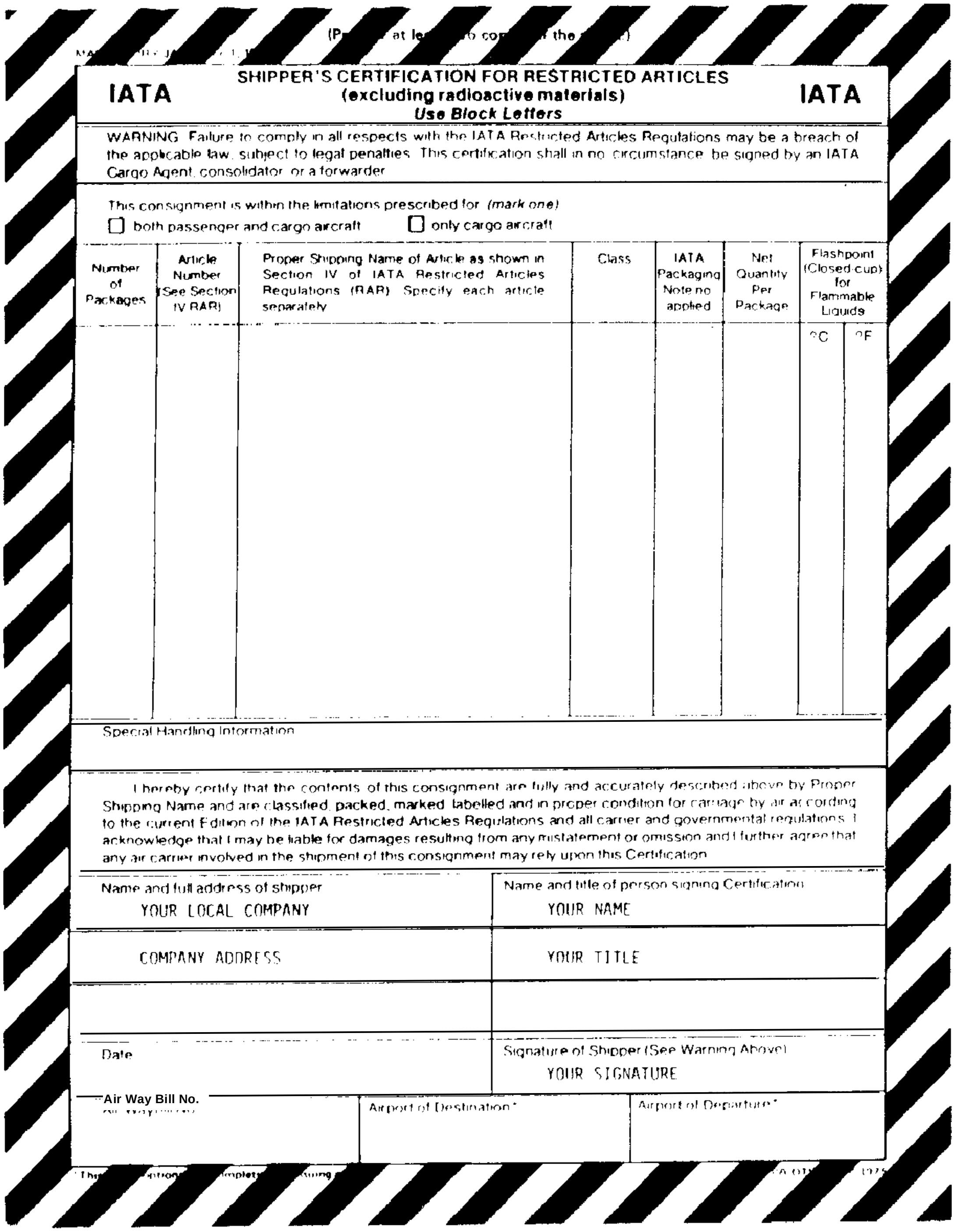


Figure D-1: Labels for Restricted Articles

Airlines have the prerogative to accept or reject any shipment.

> **CAUTION**
> *Heavy fines or imprisonment can result from shipping and packing violations. The person who signs the certification is responsible for the accuracy of the certificate.*

The “company” is not responsible for improper packing or documentation. The individual will be responsible for erroneous packing and documentation (Figure D-2). On the actual form, the diagonal slashes around the border are bright red for easy identification.



IATA **SHIPPER'S CERTIFICATION FOR RESTRICTED ARTICLES** IATA
(excluding radioactive materials)
Use Block Letters

WARNING Failure to comply in all respects with the IATA Restricted Articles Regulations may be a breach of the applicable law, subject to legal penalties. This certification shall in no circumstance be signed by an IATA Cargo Agent, consolidator or a forwarder.

This consignment is within the limitations prescribed for *(mark one)*
☐ both passenger and cargo aircraft ☐ only cargo aircraft

Number of Packages	Article Number (See Section IV RAR)	Proper Shipping Name of Article as shown in Section IV of IATA Restricted Articles Regulations (RAR). Specify each article separately	Class	IATA Packaging Note no. applied	Net Quantity Per Package	Flashpoint (Closed cup) for Flammable Liquids	
						°C	°F

Special Handling Information

I hereby certify that the contents of this consignment are fully and accurately described above by Proper Shipping Name and are classified, packed, marked, labelled and in proper condition for carriage by air according to the current Edition of the IATA Restricted Articles Regulations and all carrier and governmental regulations. I acknowledge that I may be liable for damages resulting from any mistatement or omission and I further agree that any air carrier involved in the shipment of this consignment may rely upon this Certification.

Name and full address of shipper	Name and title of person signing Certification
YOUR LOCAL COMPANY	YOUR NAME
COMPANY ADDRESS	YOUR TITLE
Date	Signature of Shipper (See Warning Above) YOUR SIGNATURE

Air Way Bill No.	Airport of Destination*	Airport of Departure*

Figure D-2: IATA Shippers Certification for Restricted Articles