# Wellsite Geology

# Reference
# Guide

# Acknowledgements

Society of Professional Well Log Analysts

Schlumberger

Atlas Wireline Service - A division of Western Atlas International

American Association of Petroleum Geologists

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# Introduction

The purpose of this reference guide is to outline and describe the duties and responsibilities of a Wellsite Geologist. In addition, it will provide a detailed series of guidelines and procedures which are followed by Wellsite Geologists during their stay at the wellsite. This will enable the maximum amount of data to be obtained, the data recorded concisely and then communicated in a timely manner to the responsible personnel.

The Wellsite Geologist is commonly in charge of all geological services at the wellsite and any geologically-related aspects while the well is being drilled. They must assimilate this data rapidly in order to provide assistance to the drilling operations and to incorporate data into the locally prepared geologic model.

Training requirements for Geological Wellsite Consultancy can be found in the IN-FACTS Training & Development Manual. It is assumed that the Wellsite Geologist will have completed all the requirements in the Geological Service modules and several related modules in the Formation Evaluation Services group, before being considered for a consultancy position.

Use this manual as an operational/training guide - not as a detailed reference on petroleum geology.

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Chapter **1**

# Duties and Responsibilities

The Wellsite Geologist is an important member of the wellsite team. They are required to monitor vital operations during the course of the well, make sure that all client requirements are carried out, and perform formation evaluation activities to ensure the well is drilled and evaluated in the most safe, efficient manner, and cost-effective.

In today’s wellsite work environment, with personnel being moved around the globe at a moments notice, it is always necessary to review the well prognosis with oil company personnel as soon as possible. This is because many times the client engineers or company man will supervise certain operations in one geographical area, but not in others, and it is best to get everyone “on the same page” before decisions are made.

A generalized list of duties and responsibilities include:

- Supervision of “Formation Evaluation” contractors (Mud Logging Geologists, MWD Logging Engineers, Wireline Logging Engineers, Coring and Well Testing Personnel)
- Logistics concerning the formation evaluation contractors and their equipment
- All safety aspects for the well and personnel during these evaluation operations
- Quality control of all evaluation results and logs prior to accepting the data or logs from those contractors
- Providing relevant correlation and well data to those contractors during their operations
- Checking all reports and logs from the evaluation contractors prior to sending them to oil company offices
- Monitoring and supervising the collecting, processing and dispatching of formation evaluation samples
- Safe-guarding the collection, storage and transmission of information and reports at the wellsite
- Wellsite interpretation of the formation evaluation data
- Checking and occasionally approving and signing of service reports and invoices of the formation evaluation contractors

- Keeping the drilling superintendent and operations geologist fully informed of all formation evaluation operations

Since teamwork is required, the geologist must work closely with the drilling team (Company Man, Drilling Engineer, Toolpusher and Rig Crew) providing advice when necessary to assist in safe, cost-effective drilling and non-drilling operations.

### Wellsite Visits

There will be occasions when additional oil company personnel will be on location (“new” staff will visit the wellsite for orientation and training). More often though, this will happen when:

- They are to witness an operation at the wellsite
- They are to gain immediate access to data, reports or logs
- They are to advise the Wellsite Geologist on alternative methods to achieve the well program objectives

Regardless of their reason, remember to be flexible when dealing with both the client and contractor, and maintain professional standards at all times.

In all cases, oil company staff members do not assume any of the Wellsite Geologist's responsibilities (except when personally communicated by the Operations Geologist).

Any advice given to the Wellsite Geologist from the specialists, which may affect the well program, should be conveyed to the Operations Geologist.

### Programs Modifications

The Wellsite Geologist usually has the authority to make minor changes to the geological aspects of the well program (e.g. sampling intervals, logging sequence), without consultation with the Operations Geologist. Such changes are decided upon by:

- The Wellsite Geologist's reasoned initiative
- On advice from the specialists, after consultation

The Wellsite Geologist should inform the Operations Geologist of any modifications at the earliest opportunity.

Any major changes to the geological aspects of the well program (e.g. different coring intervals, additional logs, extra formation tests) must have the approval of the Operations Geologist. When discussing such changes, the Wellsite Geologist should state their reasons behind the proposed change (i.e. operational constraints, advice from specialists, their own experience) and provide additional information which may prevent delays in reaching a decision (i.e. cross-checking data).

Since it is sometimes difficult to distinguish between minor changes and major changes, it is best to inform the Operations Geologist if there is any doubt concerning the changes. Even better, discuss the clients preferences before operations start.

## Rigsite Information Sources

Service companies have different ways of collecting and displaying data. Most commonly, a log-type format is used with cuttings descriptions and drilling parameters displayed graphically on a litholog/striplog or when using a spreadsheet-based format. All formats and information displayed should be discussed and agreed upon by the contractor.

There are many sources of information at the rigsite and the following is a brief list of some of the sources. The data sets available will depend upon the type of service used and the ability of the service contractor to obtain the data.

### Wireline Logging Unit

| | |
|---|---|
| VSP | Used to “look ahead”, formation top confirmation |
| RFT | Fluid sampling, Pressure determination, Oil/Water/Gas gradients |
| Resistivity | Water Saturation, Porosity, Hydrocarbon evaluation |
| Density | Lithology confirmation, Correlation, Porosity, Overpressure detection, Gas/Oil contacts |
| Sonic | Porosity, Mechanical properties, Overpressure |
| Dipmeters | Structure, Well trajectory, Facies analysis, Sedimentology |
| Sidewall Cores | Biostratigraphy, Geochemistry, Lithology confirmation Hydrocarbon evaluation |

### Mud-Logging Unit

| | |
|---|---|
| Cuttings | Geochemistry, Lithology, Correlation, Density, Calcimetry, Hydrocarbons, Shale Factor (C.E.C.), Hole Stability, Bit Condition |
| Hydrocarbons | Total gas, Chromatograph, Gas Ratios, Connection gases, Trip gases, Oil shows |
| Gases | $CO_2$, $H_2S$ |
| Engineering | Dxc, Torque, Drill Rate, Formation Pressures |

#### MWD/FEMWD unit data

| | |
|---|---|
| Directional | Borehole Trajectory (MWD), Dogleg Severity |
| Gamma Ray | Lithology Determination, Shale Content, |
| Resistivity | Correlation, Hydrocarbon Evaluation, Pressure Indication, Sw Estimations |
| Density | Lithology, Correlation, Pressure Indication, Gas/Oil Contact |

#### Others

| | |
|---|---|
| Coring | Biostratigraphy, Reservoir analysis, Porosity, Permeability |

## Wellsite Materials

At the client's pre-spud meeting, the length of the well will be estimated. This will dictate the amount of supplies you will require, both from a personal standpoint and a business standpoint. If re-supplying will be impossible, then your preparations before going to the wellsite must be thorough.

The amount of time spent at the wellsite will depend on several factors. Generally, it is best to be there a few days prior to spud to acquaint yourself with the rig crew, to observe the contractor's rig-up, and to converse with the personnel responsible for geologic data.

Review the list of contractor companies and see if they will have the supplies you will need. Most contractors will be happy to meet any “extra” requirements you may have.

### Regional Geology

It is important that the Wellsite Geologist be familiar with the regional geology of the area where the drilling is taking place. This will allow timely interpretation of data, especially if it should deviate from the prognosis. Particular aspects are:

- Nature and depth of basement within the basin
- Geologic age of the section
- Depositional environments and expected lithologies
- Tectonic setting within the basin
- Formation pressure anomalies
- Hydrocarbon occurrences within the basin
- Basin correlations

Copies of geologically related articles should be brought to the wellsite. Reprints and books can be obtained from the American Association of Petroleum Geologists (AAPG) and local geological societies.

### Well Prognosis and Prospect Description

The Wellsite Geologist should be completely familiar with all aspects of the drilling prognosis. Particular attention should be paid to any sections which may require geological decisions. These include:

- Determination of Primary and Secondary Objectives
- Determination of Casing Points
- Detection of Overpressured Intervals
- Detection of Lost Circulation Zones
- Correlation and Detection of Marker Horizons
- Determination of Geologic Basement or Economic Basement
- Selection of Logging Run Intervals

A complete set of correlation logs and reports should be compiled for use at the wellsite. Mudlogs, lithlogs and wireline logs should be used as sources of information.

### Company Requirements

Prior to arrival at the wellsite, the geologist should be aware of their responsibilities and their authority. Decisions that are to be made at the wellsite and those that are made by the drilling foreman or the exploration office must be differentiated. It is important that all channels of communication for every situation be clear and well defined. A list of names and, where applicable, office and home contact numbers and addresses should be compiled. Contact numbers for contractor personnel are also useful.

### Material Requirements

The Wellsite Geologist should be self-sufficient in terms of material supplies at the wellsite. The actual requirements will vary, depending on the reporting formats and descriptive requirements of the client. The following is a comprehensive list of possibilities:

- Copy of the well prognosis
- Copy of prospect footage
- A copied set of correlation logs

- Set of company report forms, including:
  - Morning Report Forms
  - Afternoon Report Forms
  - Cuttings Description Forms
  - Sidewall Core Description Forms
  - Core Description Forms
  - Wireline Quality Control Forms
  - Mud-Logging Quality Control Forms
- Set of data transmittal forms
- Grain size comparator
- Rock Color Chart
- Wireline/MWD Log Chart books (company specific)
- Set of log sepias and paper copies (if required):
  - Lith Log
  - Core Log
  - Pressure Evaluation Log
  - Temperature Log
- Stationery for transmittal, drafting etc. including:

  (paper clips, rubber bands, envelopes, note pads, pencils, pens, marker pens for coring, clipboards, large graph paper for RFT plots, Horner plots etc.)
- Microscope

  This is usually supplied by a contractor. Check the type, quality and magnification (see Appendix A). If it is not suitable request another.
- Chemicals

  Most chemicals are supplied by the mud-logging contractor. Check for those required in special carbonate tests or for preservation of geochemical samples. If not supplied by the contractor, request them. Ensure that replacement stocks are available (and note the source).

Many companies use computers for wellsite data storage and reporting. If the Wellsite Geologist requires a computer, check on office space availability at the rigsite or if a mud-logging unit is to be used. Power supply and plug/socket compatibility must be checked. Back-ups of *software, blank disks, software/hardware manuals* and *anti-virus software* are necessary.

### Sampling Requirements

Once the sampling requirements have been ascertained, they should be passed on to the mud-logging contractor. Sufficient sample boxes, sample bags, sample envelopes, and sample vials should be present at the wellsite. If they are not, it is essential that the geologist be aware of the lead time required for their acquisition. Particular care should be taken over bulky items such as geochemical cans or core boxes as these may require special transportation. In addition to those required for the sample intervals, extra bags or envelopes should be available for “spot” or “hot shot” samples.

A sample is useless if the test/drilling conditions and depth data are not indicated on the sample container. Also, the names and addresses of sample recipients should be obtained for the efficient dispatch of the samples.

Sample catching and packaging is usually the job of the mud-loggers, however the geologist must be aware of the correct methods, intervals and requirements to ensure that data quality is maintained.

It is always best to take more samples of anything that may be required (for later reference), even without specific instructions. These samples can always be removed if deemed unnecessary.

## Pre-Well Responsibilities

Generally, the Wellsite Geologist will be notified that they will be responsible for a well some time before the well is spudded. This time period should be spent, either collecting all available information or reviewing the already collected information.

If the geologist has the responsibility to collect the information pertaining to the well, the process should be exhaustive and thorough. General information concerning a field or specific information for a well can be obtained from the oil company owning the field, well log libraries, production reporting services, oil industry journals, regulatory agencies, and from communication within the oil company.

Once collected, the information is used by the Wellsite Geologist to come up with a “most probable” scenario as to what the subsurface adjacent borehole will look like. An open mind must be maintained when looking for hydrocarbons. Since the unknown is frequently confused with the unattractive. It is also important to guard against negative thinking, resulting from limited data. At the same time, it is important to remain optimistic and realistic when reviewing the data. It should be remembered that oil and gas are common substances in sedimentary basins.

The types of information that should be collected include:

| Geological Data | Engineering Data |
|---|---|
| Correlation Logs (1-inch & 5-inch)<br>Any Core Data<br>Paleo Data<br>Directional Survey Data<br>Post-Well Reports | Pressure Plots of Correlation Wells<br>Production Data of Correlation Wells<br>Bit Records<br>Formation Water Analysis (for Rw)<br>Well Problems Encountered |
| **Regulatory Data** | **Geophysical Data** |
| State/Local Regulations<br>Approved Financial Estimates (AFE) | Seismic Base maps<br>Gravity and Magnetic Maps |

## Geologic Maps

During the preliminary stages, much of the geological effort is directed towards drafting subsurface maps or reviewing previously drafted maps, covering the perspective field. Whether drafting or reviewing, it must be remembered that a map is never finished, but the map must be as complete as possible with the data available at the present time. It is best to remember that the subsurface is usually much more complex than is generally envisaged.

With regards to early subsurface maps, many early rotary holes were drilled unintentionally crooked by as much as 40 to 50 degrees, with no surface indications apart from "pay dirt" being absent or it occurring much deeper than expected. Consequently, early geological data and subsurface maps require very thorough investigation.

## Dry Holes

Dry holes should never be considered fruitless, because valuable data can be obtained from the well even if no hydrocarbons were indicated. Successful exploration, in many cases, requires that many dry holes be drilled (even though the aim of the industry is to drill as few dry holes as possible).

When reviewing well data, it is prudent to note that dry holes may be due to the following:

1. *The trap was absent or open:* This can be due to poor seismic quality or incorrect interpretation of data
2. *The trap shifted position*: This may be due to faulting or folding
3. *A crooked hole*: Traps formed by faults, and those around the flanks of salt diapirs require highly accurate directional drilling,

and reservoirs can be missed by slight deviations from the projected borehole trajectory.

4. *The reservoir rock may be absent due to*: Shaling Out, Faulting Out, Erosion off a structural high, Failure to drill deep enough.

5. *No oil or gas in the reservoir*: Even more difficult than attempting to justify why hydrocarbons should be present (the pre-well proposal), is explaining why, when all the requirements for the generation and accumulation of hydrocarbons are present, the well was found to be dry.

   This can occur because there was no supply of hydrocarbons available, the trap developed after the hydrocarbons had migrated out of the reservoir, or the hydrocarbons may have “spilled-out” or had been flushed out of the reservoir.

6. *Failure to recognize hydrocarbons during drilling*: This can be due to excessive mud weights causing flushing of the formations and a thick filter cake build-up. Small diameter holes causing only a small volume of rock being crushed and carried to the surface for observation. Poor log quality or incorrect interpretation techniques. Drilling fluid contaminants masking hydrocarbon shows. Failing to test a suspected reservoir.

## Summary

When the Wellsite Geologist arrives at the wellsite, they should be fully confident in their abilities, have an idea of how the well is to be drilled and evaluated. They should know where wellsite information can be gathered, and who to look to for assistance and advice.

Drilling, evaluating and completing a well is a team effort and the Wellsite Geologist is a valuable member of this team.

•Notes•

Chapter **2**

# Drill Cuttings Evaluation

There is no substitute for accurately logged and collected samples! It can not be stressed enough about the importance of good depth control and sample retrieval techniques. Even though the cuttings will be looked at by members of the mud-logging crew, they often spend more time actually catching the samples and maintaining equipment, hence, the samples are given only a perfunctory look. The onus is on the Wellsite Geologist to provide a detailed description of the drilled cuttings.

Those rock samples can be obtained from several sources at the rig site:

- Shale Shakers (upper & lower screens)
- Desanders, Desilters and Mud-Cleaners (not lagged)
- Flowline and Possum Belly (not lagged)

At the shale shaker, it is essential that the geologist know the shaker screen sizes, and the grain-size of the cuttings that can be recovered from each screen. A representative sample should be caught from a combination of the screens, not just the top or bottom screen.

While it is desirable to use the finest shaker screens at all times, this is impractical due to high flow rates or when using heavy, viscous mud systems. When this happens, samples can be obtained from the desanders and desilters. These devices recover fine solids from the mud system and should always be checked during routine or top hole drilling. When drill breaks or clastic reservoir sections are expected, then more regular samples should be examined to check for the presence of very fine grained clastics. When the centrifuge is used to recover very fine material, it should also be checked for very fine clastics (if weighted mud systems are used, the mud-cleaner will not be run to prevent excessive barite removal). Samples may also be obtained directly from the flowline using either a very fine sieve or a mudcup and sieve.

The selection of shaker screens and the use of solids control equipment is usually decided upon by the mud-engineer or company man. If sampling dictates a change in screen sizes, the geologist should discuss this requirement with them. Even though the sampling interval is outlined in the well program, it should be noted that if drilling is slower or faster than expected, the sampling rate should be changed accordingly. If it is acceptable, use sample catchers. This allows the mud-logging crew more time to monitor their equipment. When using the sample catchers, make sure they are competent at catching representative samples.

## Cuttings Description

Each lithology should be accurately described, and that observations recorded in the following order:

a. Rock Type
b. Classification
c. Color
d. Hardness/Induration
e. Grain Size
f. Grain Shape
g. Sorting
h. Luster
i. Cementation/Matrix
j. Visual Porosity
k. Accessories/Inclusions
l. Oil Show Indications

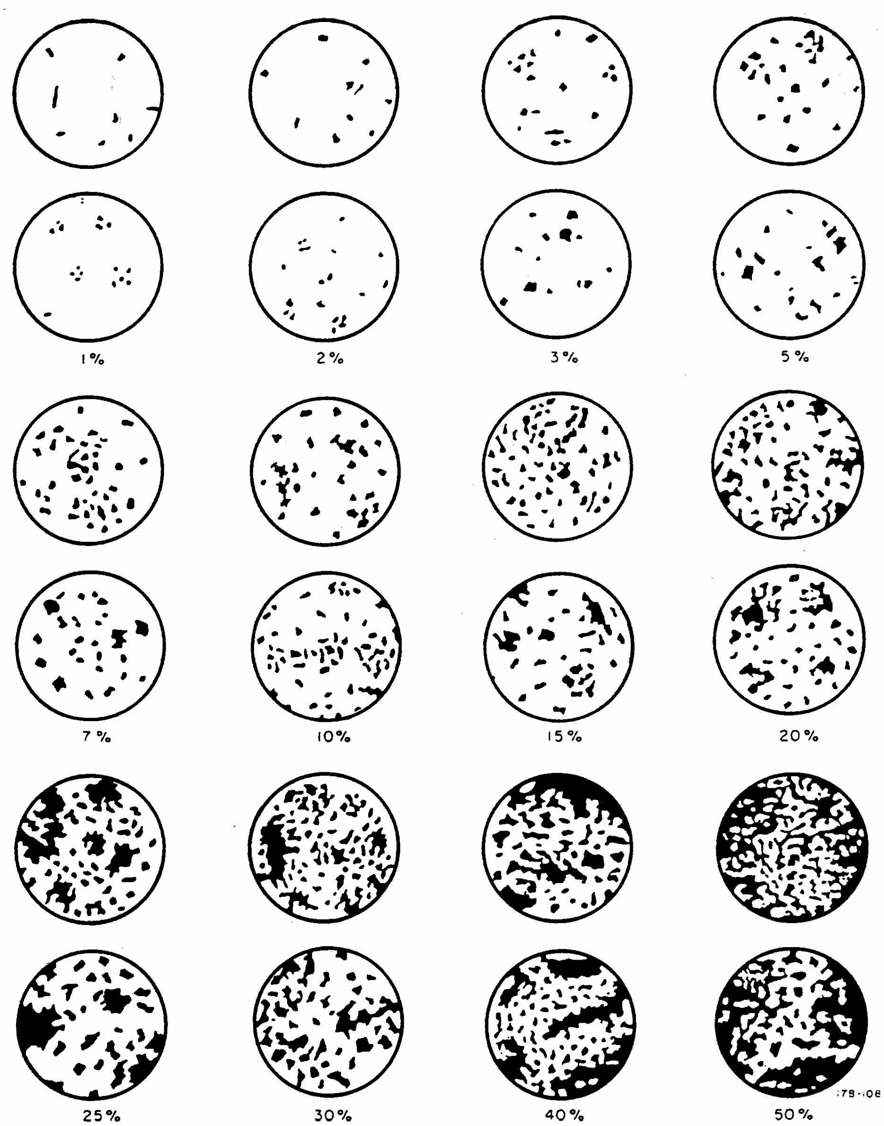



**Figure 2-1: Comparison Charts for Visual Estimation of Percentage Composition**

The description must be graphic and include all observable features. This detailed description format, should be followed at all times.

Figure 2-1 illustrates percentage composition for cuttings samples.

In addition to the description format, there are standardized abbreviations which should be used on the logs (Appendix A). These standards are essential for proper understanding. If, during your description, you notice a feature which does not have an abbreviation, spell out the feature instead of making up an abbreviation.

## Clastic Rocks

These are normally siliclastic sediments, consisting of broken, weathered and transported fragments of existing rocks. During the process of diagenesis, further chemical and mineralogical changes may occur, but these should not alter the essential character of the rock.

### Rock Type

The most commonly used well-site method to describe rock type is based on the **grain size** and **induration of the fragments** making up the rock. Three major sub-divisions of grain size used to describe rock types are:

- Rudaceous: grain size discernible to the naked eye
- Arenaceous: grain size discernible with a microscope
- Argillaceous: grain size indiscernible in the field

The two major sub-divisions of induration used to describe rock types are:

- Unconsolidated: occurring as individual grains
- Consolidated: grains held together by cement or through dewatering

**Examples of "clastic" rock types are**:

| | CONSOLIDATED | UNCONSOLIDATED |
|---|---|---|
| **RUDACEOUS** | Conglomerate<br>Breccia<br>Tillite | Gravel<br>Scree<br>Till |
| **ARENACEOUS** | Sandstone<br>Siltstone | Sand<br>Silt |
| **ARGILLACEOUS** | Claystone<br>Shale | Clay<br>Clay/Mud |

## Classification

The mineralogical and chemical composition of clastic rocks will be the basis of any further differentiation of rock types. These characteristics may even assist in determining the rock type. Some examples are:

### Sandstone

| | |
|---|---|
| Orthoquartzite | Quartz sandstones with quartz cement. Quartz constitutes more than 75% of the rock |
| Greywacke | Badly sorted and incompletely weathered fragments and rock materials in a finer grained matrix of similar composition. Quartz constitutes less than 75% of the rock and lithic fragments are more common than feldspars. |
| Arkose | Coarse fragments of quartz and feldspars in a calcitic or ferriginous cement. Quartz constitutes less than 75% of the rock and feldspars are more common than lithic fragments |

### Claystone/Shale

The major difference between these rocks is fissility. A claystone is a structureless mass of clay minerals. A shale consists of finely laminated clay minerals exhibiting fissility and showing strong parallelism.

## Color

When determining the color of a sample, inspect the sample when wet, as it will reveal colors more vividly. Dried cuttings can be viewed to allow a better discrimination of subtle hues, color shades and structures.

Color is a useful indicator of depositional environment, especially in argillaceous rocks. For example:

- Red & Brown: ferric iron, an oxidizing environment
- Green & Grey: ferrous iron, a reducing environment
- Dark Brown: organic material, possible source rock
- Black: an anaerobic environment

Each sample should be described, distinguishing the colors of:

a. Rock Particles
b. Staining
c. Martix and Cement
d. Accessories

When more than one color is present, suitable descriptions are:

| | |
|---|---|
| Varicolored | Iridescent |
| Speckled | Spotted |
| Banded | Scattered |
| Disseminated | Variegated |

## Hardness and Induration

This is the physical parameter based on the amount of force required to break apart the cutting, using a sample probe. The Moh's Hardness Scale, though not a quantitative scale, defines a mineral's hardness by its ability to scratch another (one with a lower number) and should not be used.

| Standard | Hardness | Standard | Hardness |
|---|---|---|---|
| Talc | 1 | Orthoclase | 6 |
| Gypsum | 2 | Quartz | 7 |
| Calcite | 3 | Topaz | 8 |
| Fluorite | 4 | Corundum | 9 |
| Apatite | 5 | Diamond | 10 |

Induration is the process by which a sediment is converted into a sedimentary rock, generally termed diagenesis. Since particles will be of relatively uniform hardness, induration will be a function of the type and quantity of cement. Some descriptions are:

### Rudaceous and Arenaceous Rocks

- Unconsolidated: Cuttings fall apart or occur as individual grains.
- Friable: Rock crumbles with light pressure. Grains easily with a sample probe.
- Moderately Hard: Grains detach with sample probe. Cuttings can be broken with some pressure.
- Hard: Grains are difficult to detach. Extreme pressure causes cuttings to break between grains.
- Extremely Hard: Grains cannot be detached. Cuttings will break through the grains.

### Argillaceous Rocks

- Soluble: Readily dispersed (goes into suspension) by running water.

- Soft: No shape or strength. Material tends to flow.
- Plastic: Easily molded and holds shape. Difficult to wash through a sieve.
- Firm: Material has definite shape and structure. Readily penetrated and broken by sample probe.
- Hard: Sharp angular edges. Not readily broken by the probe.

Several other descriptive terms include:

| | |
|---|---|
| Brittle | Blocky |
| Loose | Amorphous |
| Dense | |

Remember, this is the description of the cutting as a whole.

### Grain Size

An accurate visual estimate can be obtained using a Grain Size Comparator.

Grain size determination from drill cuttings should follow a disciplined procedure to obtain an accurate overall estimate of:

1. Size of individual grains
2. Mean size of grains in an individual cutting
3. Mean size of grains in all cuttings of the same lithology

It is best to report the weighted average, taking into account the amount of each grain size. Where the largest grains present are much larger than the weighted average, the maximum size should be reported. When the range of grain sizes is so wide and diverse (making a weighted average meaningless), note the minimum and maximum of the range.

### Grain Shape

For practical well-site descriptions, grain shape is a function of roundness and sphericity (see Figure 2-2). The Grain Size Comparator can be very useful in shape determination. Shape is of critical importance in sample descriptions, because it give clues to two important geologic parameters:

1. Mode and distance of transport
2. Porosity and permeability

Descriptive terms include:

- Angular: Edges and corners are sharp. Little or no wear is present

- Subangular: Faces are untouched, but edges and corners are rounded
- Subrounded: Edges and corners are rounded to smooth curves. The areas of the original faces are reduced
- Rounded: Original faces are almost completely destroyed, but some comparatively flat faces may be present. All original edges and corners are smoothed off to broad curves.
- Well Rounded: No original faces, edges or corners remain. The entire surface consists of broad curves. Flat areas are absent.

In addition, other descriptive terms may be used to supplement the above descriptions. For example:

| | | |
|---|---|---|
| Sharp | Elongate | Bladed |
| Flat | Rod | Blocky |
| Platy | Conchoidal | Irregular |
| Disk | Faceted | Fibrous |

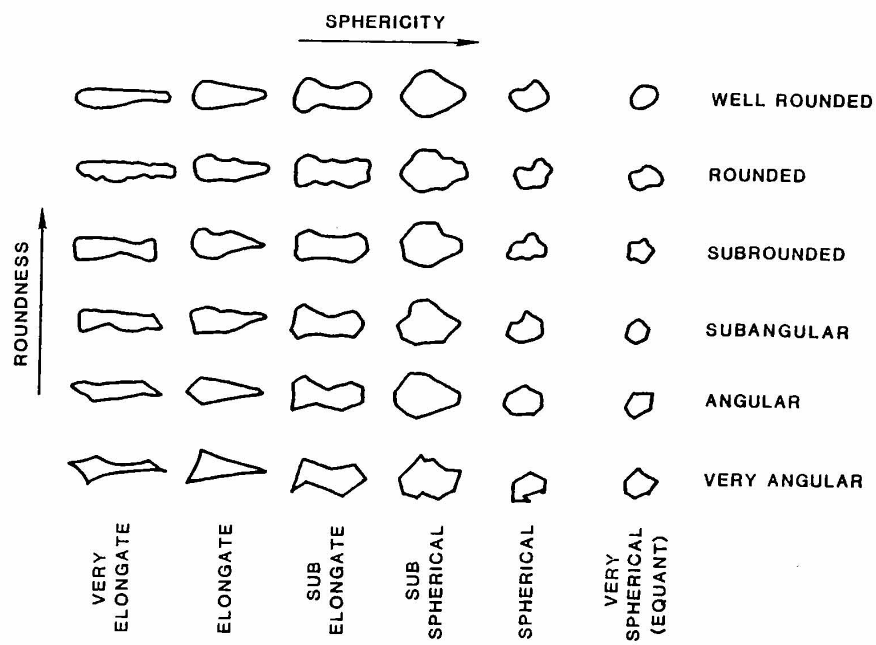



**Figure 2-2: Particle Shape - Roundness vs. Sphericity**

### Sorting

Sorting can be the most difficult and subjective assessment made by the Wellsite Geologist during sample descriptions. Again, the Grain Size Comparator will be useful. It is generally understood that if more than 50%

of the cuttings are of the same modal size, then the sample is well sorted. Most descriptions contain:

| | |
|---|---|
| Extremely Well Sorted<br>Very Well Sorted<br>Well Sorted | **Monomodal** |
| Moderately Sorted<br>Poorly Sorted<br>Very Poorly Sorted | **Polymodal** |

### Luster

This is the term used to define the surface features of the cutting under reflected light. It is best to observe the surface texture of both wet and dried samples with the naked eye and under the microscope. Rotating the sample tray under the light source also assists in describing texture. Common terms are:

- <u>Coated</u>: Precipitated or accretionary material on the surface of the cutting. Not thick enough to develop a visible color
- <u>Vitreous, glassy, faceted</u>: Clear, shiny, fresh appearance
- <u>Silky, pearly (nacreous), polished</u>: Lightly etched or scoured
- <u>Frosted, dull, etched:</u> Deeply etched or scoured
- <u>Pitted:</u> Solution or impact pits, often pinpoint size
- <u>Striated</u>: Parallel abrasion lines or scratched

Argillaceous rocks also exhibit observable surface texture under reflected light. Common terms are:

| | |
|---|---|
| Earthy | Waxy |
| Silky | Resinous |

### Cement or Matrix

Cementation is the result of crystallization due to precipitation of silica, carbonates and other soluble minerals into the pores of clastic rocks. Cementing materials may be derived from, or related to, the rock particles, matrix or can be externally derived. Common cementing agents are:

| | | |
|---|---|---|
| Calcite | Silica | Clays |
| Siderite | Dolomite | Pyrite |

Pressure solutions and recrystallization at grain boundaries may lead to a rock becoming indurated and hard, without cementing agents being discernible.

The difference between “cement” and “matrix” is one of degree, and may not be obvious in the sample. In general, where intergranular contact does not occur, the fill material between grains is matrix. Matrix material does have cementing qualities which holds the grains fixed relative to each other.

An alternative method of discrimination is to define matrix as primary sedimentary material, and cement as secondary, chemically precipitated material.

## Visual Structures

Structures in individual cuttings samples are usually indiscernible. To detect bedding characteristics, it may take several samples over several intervals to allow bedding to be recognized.

Some structural types which may be visible in wet or dried cuttings are:

- Fractures - usually with some type of filling
- Jointings/Partings
- Bioturbation
- Lamination

Slickensided surfaces should be carefully scrutinized. The gauge protection on bits will scrape the sides of the bore-hole, giving a striated/glassy appearances on those cavings.

Fixed Cutter bits, with their diamond gauge protection and diamond cutting surfaces can change the appearance cuttings. At high temperatures, metamorphism can even take place, especially when drilling shales, fine sands, chalks, and other such lithologies.

## Visual Porosity

The porosity in rudaceous and arenaceous rocks is primarily interparticle, consisting of the void spaces between the grains. Once a packing geometry has been established during compaction, further porosity changes will be the result of the introduction of, or removal of, cementing material or solution of grains. The theoretical porosities for various packing geometries are:

| Geometry | Porosity | Occurrence |
|---|---|---|
| cubic | 47.6% | young sediments |
| hexagonal | 39.5% | compacted sediments |
| rhombohedral | 25.9% | most sedimentary rocks |

The theoretical maximum porosity for a clastic rock is therefore about 26%, and is generally much reduced by other factors. A wellsite guide for estimating porosities is:

| | | | |
|---|---|---|---|
| > 15% | Good | 5 to 10% | Poor |
| 10 to 15% | Fair | < 5% | Trace |

Unless absolutely known, the Wellsite Geologist should never use numerical values in estimating porosity when dealing with cuttings, just use descriptive terms.

## Accessories or Inclusions

In addition to the major minerals making-up the rock cuttings and cementing material, other minerals in trace quantities may be present. Although constituting a minor fraction of the cuttings sample, accessories are of disproportionately great diagnostic and descriptive value. Even if the accessory mineral cannot be named, it should be carefully described.

Make note of secondary enlargement of grains, or crystal growth. Terminology for crystal structure is:

- Anhedral - no visible crystal form
- Subhedral - partly developed crystal form
- Euhedral - well developed crystal form

Fossils are common accessory materials. Macrofossils are rare, though fragments may be present. Microfossils may be present under the magnification and a brief description, or possible identification, should be included. Fossil amount is estimated as:

| | |
|---|---|
| > 25% | Abundant |
| 10 to 25 | Common |
| < 10% | Trace |

### Fluorescence

For visual fluorescence percentage estimation see Figure 2-3.

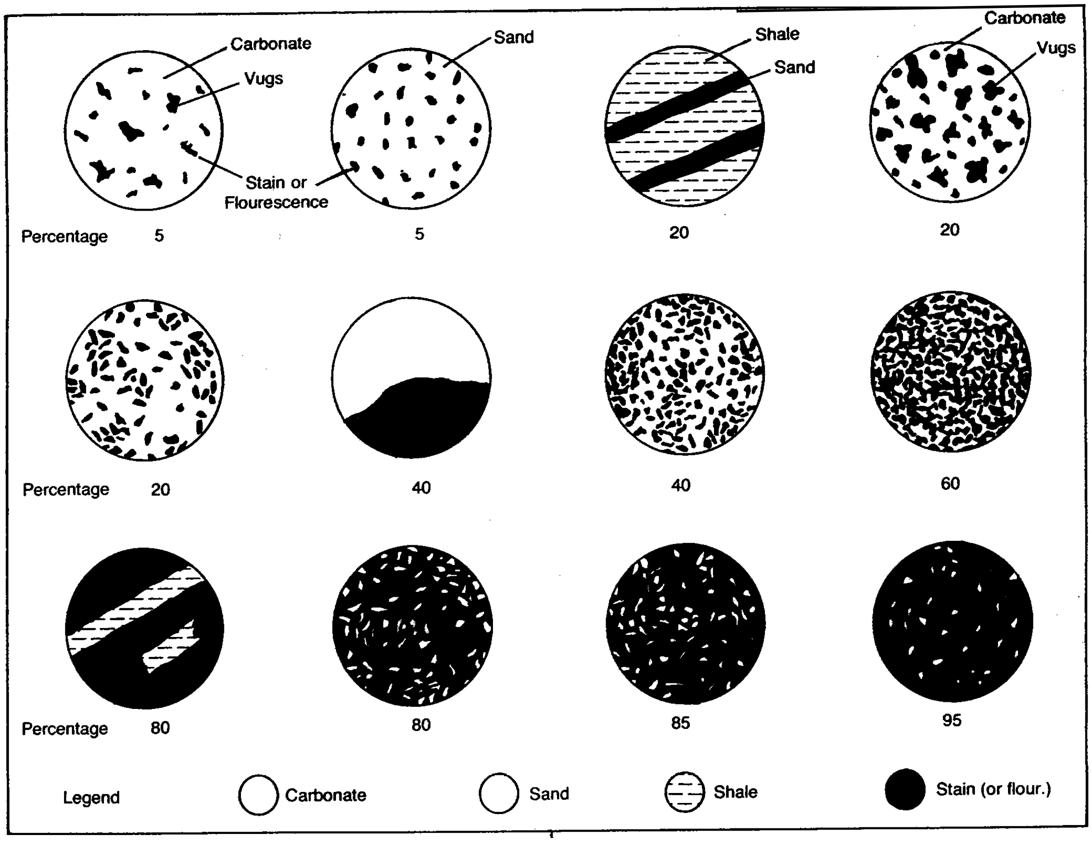



**Figure 2-3: Visual Fluorescence Percentage Estimation**

More detailed information on fluorescence and hydrocarbon show analysis can be found in Chapter 3.

## Carbonate Rocks

Carbonate rocks, in this section, will be rocks composed of calcium carbonate ($CaCO_3$) and calcium magnesium carbonate ($CaMg(CO_3)_2$). Carbonate rocks are difficult to classify, due to the complexity of sources and types of occurrences. However, they can be broken down into two simple classifications, based on their origin:

| Clastic | Chemical |
|---|---|
| *Lithoclasts*<br>fragments of pre-existing rocks | *Lutaceous*<br>lime mud or micrite |
| *Bioclasts*<br>fossil fragments | *Crystalline*<br>sparry limestone or dolomite |

### Rock Type

To determine rock type, it is best that the sample be etched and rinsed before analysis. Samples are etched in 10% HCI and rinsed using distilled water. During etching, test the samples for reactivity. As with any test, to have any real value it must be applied systematically. Typical reaction rates are:

1. **Limestone**

   Sample reacts instantly and violently, it will float on top of the acid and move while on the surface. It will completely dissolve within minutes and leave the acid frothy.

2. **Dolomitic Limestone**

   Sample reacts immediately, but moderately and is continuous. It will move about in the acid from top to bottom.

3. **Calcitic Dolomite**

   Sample reacts slowly and weakly at first, but accelerates to a continuous reaction after a few minutes, with some bobbing on the bottom of the dish.

4. **Dolomite**

   Very slow and hesitant reaction. Bubbles evolve one at a time. Acid may have to be warmed for reaction to proceed. It will leave the acid milky.

Autocalcimeter’s can assist in determining the percentages of limestone and dolomite in a sample.

Various “stain kits” are available to assist in determining the types of carbonates in the sample. Most staining procedures require that the sample be etched initially and the most common stain test for carbonates is

Alizarin Red S. After etching in HCl, the sample is placed in cold Alizarin Red S for several minutes. Limestone will stain a deep red, while dolomites will remain unaffected.

## Classification

Although there are numerous carbonate classification schemes available (most are very useful), the scheme adopted by the petroleum industry is the “Dunham Classification System”. This is a classification of clastic carbonate rocks. Expansion of the bioclastic group was prepared by Embry and Klovan (1971), and Cuffey (1985). In general, Dunham's basic classification is sufficient for cuttings analysis. The classification is:

1. **Mudstone**

   Composed of lime mud (smaller than 20 microns) and less than 10% grains. Mud supported.

2. **Wackestone**

   Composed primarily of lime mud, with more than 10% grains (larger than 20 microns). Mud supported.

3. **Packstone**

   Composed primarily of grains, and grain supported. Greater than 10% interstitial mud matrix and occasionally sparry calcite or pore space.

4. **Grainstone**

   Composed of grains, and grain supported. Less than 10% interstitial mud matrix.

5. **Boundstone**

   Original constituents were bound together and supported in place, by organic growth.

6. **Crystalline**

   All original textures are lacking due to the effects of recrystallisation. Distinct crystal faces, with occasional relicts.

Another very common system is Folk's classification. This system makes use of four particle types (pellets, coated grains, clasts and skeletal fragments) as Allochems, plus a description of the matrix as either “micrite” or “sparite”.

Micrite - microcrystalline calcite, referring to clay-sized carbonate

Sparite - sparry calcite, generally crystals > $10\mu$.

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Original components not organically bound during deposition | | | | | | Original components organically bound during deposition | | |
| of the allochems, less than 10% > 2 mm diameter | | | | of the allochems more than 10% > 2 mm | | boundstone | | |
| contains carbonate mud (particles less than 0.03 mm diameter) | | | mud absent | matrix supported | grain supported | organisms acted as baffles | organisms encrusting and binding | organisms building a rigid framework |
| mud-supported | | grain supported | | | | | | |
| less than 10% grains | more than 10% grains | | | | | | | |
| mudstone | wackestone | packstone | grainstone | floatstone | rudstone | bafflestone | bindstone | framestone |

**Figure 2-4: Dunham Limestone Classification, With Modifications Of Embry & Klovan**

Folk defines carbonates depending upon the proportions of allochems, micrite and sparite. There are four classes of limestone, each being sub-divided:

**Class I** Sparry Allochemical Rocks or Sparites

These contain allochems cemented by sparry calcite (generally equivalent to Dunham's Grainstone). They tend to be typical of beaches, bars and submarine shoals where currents have washed away the calcareous muds.

**Class II** Microcrystalline Allochemical Rocks or Micrites

These contain allochems cemented with micrite (generally equivalent to Dunham's Wackestone and Packstone). Sparite is rare as little free pore space is available.

Proportion of allochems range from 80% to 10%. The distinguishing characteristics between microcrystalline allochem rocks and microcrystalline rocks is at 10% allochems. These Class II limestones are typical of lower energy areas where calcareous mud was not removed.

Rocks will fall between these two classes, with pores partly filled with calcareous mud and partly filled with sparite. These are listed as “poorly washed sparites”.

**Class III** Microcrystalline Rocks

These represent rocks from Class II, where the allochem content is between 10% and 0% (generally equivalent to Dunham's Mudstone). They are typical of shallow, sheltered lagonal areas or broad submerged shells.

Where these rocks have been disturbed by burrows or current action, the term “dismicrite” is used.

**Class IV** Biolithite

These are rocks such as reefs and bioherms, where organic structures are growing in place and forming a coherent resistant mass during growth. No attempt is made to subdivide these, but if broken up they will fall into Class I or II. This distinction is difficult to ascertain from cuttings samples.

The sub-division of Classes I, II and III depends upon the allochem. Of all particles present the “clasts” are the most significant, because of their implication of shallow water, lower wave base or uplift. A rock is termed an “intraclastic” if more than 25% of the allochems are clasts, regardless of the other allochems. The next most significant are the “oolites”, and if the allochems are greater than 25% oolites, the rock is classified as oolitic. If neither if these apply, then the allochems will be pellets and/or fossils. If the fossil to pellet ratio is greater than 3:1, it is termed “biogenic”, and if less than 1:3, it is termed “pelleted. Between the two, it is termed a “biogenic pellet rock”.

| Principle allochems in limestone | Limestone types | |
|---|---|---|
| | Cemented by sparite | with a micritic matrix |
| skeletal grains (bioclasts) | biosparite | biomicrite |
| ooids | oosparite | oomicrite |
| peloids | pelsparite | pelmicrite |
| intraclasts | intrasparite | intramicrite |
| limestone formed in situ | biolithite | fenestral limestone - dismicrite |

**Figure 2-5: Classification of limestones based on composition (after Folk)**

The Leighton and Pendexter system is a third carbonate classification scheme. It is a clastic textured system involving four textural components (grains, matrix, cement and pores). Organic frame builders and recrystallized components are added to include reefal and crystalline limestones.

## Color

In carbonates, color may be of less importance than in clastics. It is, however, important that color be accurately described, because color variance is often so slight, that recognition and discrimination may depend upon a precise description of shade and hue. A “Rock Color Chart” is useful.

Variations in color may be the result of the presence of detrital material (clay) or from the substitution of metallic ions into the mineral lattice. When describing the color of carbonates, always stress the predominant color, though on many occasions colors will be mixed and the suitable modifying adjective (e.g. variegated, mottled) should be used.

As always, the color is described when the sample is wet. The wet surface will decrease the value (lightness) of color, but does not change the chroma (color saturation) of the rock.

## Hardness or Induration

It should always be remembered that calcite has a lower strength than quartz. In addition, the hardness of the sample can be greatly distorted by internal cavities.

Descriptive terminology for hardness and induration of carbonates is the same as those used for clastics.

### Grain Size

Carbonate rocks contain both physically transported particles (oolites, intraclasts, fossils, and pellets) and chemically precipitated minerals (either as pore-filling cement, primary ooze, or as products of recrystallization and replacement). Therefore, the size described must be a double one, so that one can distinguish which constituent is being considered.

The Grain Size Comparator can be used effectively for many grain types and crystalline forms.

### Grain Shape

To make the grain shape more understandable, the grain or particle type is necessary. Categories of grain types are:

| Type | Examples |
|---|---|
| Detrital Grains | Rock fragments, Intraclasts |
| Skeletal Grains | Crinoidal, Molluscan, Algal |
| Pellets | Fecal pellets, Grains of mud |
| Lumps | Composite grains, Algal lumps |
| Coated Grains | Oolites, Pisolites, Encrusted Grains (Foraminiferal) |

Terminology used for clastic rocks (roundness and sphericity) may be used to describe such particles, but it should be remembered that the particles inherent shape will be a control over shape after abrasion and weathering.

Shell fragments, being brittle and platy or fibrous, tend to split into smaller fragments upon transportation. Some rounding may occur, but rarely will platy particles become spherical.

### Sorting

Sorting in carbonates is a function of mean grain size. However, due to the various types of grains in carbonate rocks, little is known about sorting. As an introduction, any meaningful boundary between “well sorted” and “poorly sorted” will depend on the mean grain size of the sample.

Next, the particle type will have an effect on particle sorting. For example, if all the “grains” are of the same fossil, the sorting would be “good” regardless of any winnowing currents, because of the inherent size of the animals. To describe sorting in carbonates, two conditions must be met:

1. particles of diverse kinds and sizes are present in a sequence of samples
2. the particles are segregated into layers of varying mean grain size

Again, the Grain Size Comparator will be useful in describing sorting.

### Luster (Surface Texture)

The significance and terminology of carbonate surface textures is the same as used for clastic rocks. However the lower hardness of carbonate minerals (calcite 3, dolomite 3.5-4 on the Mohs scale) compared to quartz (7), and their high solubility, results in surface textures being less defined and easily lost after deposition.

In carbonates, this might be called "surface relief" or "grain micro-shape". In addition to the terms used for clastics, some common terms are:

- **Rhombic**: perfectly formed rhombs of nearly equal size, medium to coarse (usually pure dolomite)
- **Sucrosic**: Sugary, similar to rhombic, but finer, lacking the perfection of crystal form (usually calcitic dolomite)
- **Microsucrosic**: very finely sugary, often quite friable (usually calcitic dolomite)
- **Grainy**: Not vividly crystalline, but with definite grains, often chalky in part (limestone or dolomitic limestone)
- **Oolitic**: Spheroidal or smooth-surfaced grains with concentric internal structure. Combinations are used where applicable.

### Cement or Matrix

The differences between secondary mineralization, cementation, and diagenetic changes are strictly one of degree. In carbonate rocks all or none may be present, and in varying degrees. The above three processes may be continuous and the rock may undergo numerous cycles of diagenetic change. Fracturing, dolomitization and re-dolomization may further complicate and influence the process. Lime mud and a clay matrix will be an integral part of the deposited sediment, whereas cement forms after deposition, growing within a framework, defined by the particle packing. The essential difference between the two forms is that cementation is a result of crystallization from an aqueous solution with unimpeded growth into a void. Matrix recrystallization occurs at the crystal lattice level in the solid phase.

Secondary mineralization, sedimentary, and diagenetic cementation will all contribute to the induration and strength of the rock. Nevertheless, so many other factors influence these that it is not recommended that such terms as "weakly" or "strongly" be used. Preferable terms are:

| | |
|---|---|
| Partially | Well |
| Poorly | Very well |
| Moderately | Extremely well |

These terms are based upon an assessment of the amount of inter-granular cement and of pressure recrystallization at grain boundaries. If recrystallization occurs across grain boundaries, resulting in a total crystalline structure, the term “cement” should not be used.

## Visual Structure

The most significant structural features of carbonate rocks are post-lithification voids (e.g. fractures, fissures, joints, vugs, stylolites). They have a major impact on rock strength, porosity and permeability, and are significant in terms of reservoir potential and lost circulation problems.

Evidence of mineralization and crystal growth may point to partial in-filling of fractures, channels and vugs. Other, less prominent features are rock staining and slickensides.

## Visual Porosity

Pore systems in carbonates are generally complex in their geometry and genesis. Porosity can be formed by the inclusion of voids within the sediment particles, from sediment packing or sediment shrinkage, by fracturing or brecciation of the rock, by selective solution of particles within the rock, or by indiscriminate solution of a mass of rock. Pore size can vary from one micron to hundreds of meters.

### Archie's Classification

Archie's classification of limestones is rarely taught at universities, but is of particular interest to the oil industry because it is based upon porosity variations. The classification is rarely used by itself, but usually as a supplement to generic or particle type systems such as Dunham or Folk. For an Archie classification to be made, the sample must be freshly broken and preferable dry. Archie recognized two types of porosity;

- Matrix Porosity (graded I, II and III)
- Visible Porosity (graded A, B, C and D)

**Matrix:** Refers to the actual rock components and if matrix porosity is present it is found between the particles (intraparticle). It is usually too fine to be seen under x10 magnification unless the components are relatively large (e.g. dolomite crystals, ooids). Normally the “invisible” matrix porosity is estimated by classifying the surface appearance under x10 magnification.

- I compact, dense, flaky, conchoidal appearance on breaking
- II chalky, earthy, generally soft, crystalline appearance absent
- III sucrosic, crystalline or grandular, loose, poorly cemented

It is often possible to find gradations between these classes, for example:

I/II hard carbonate with chalky appearance, not friable and will not absorb water

I/III a partly cemented sucrosil granular carbonate, not friable

**Visible**: These are individual pores or vugs visible with x10 (greater than 10μ) magnification.

- A no visible pores with x10 (pores < 10μ)
- B pores visible with x10 (pores < 100μ)
- C pores visible with the naked eye (pores 100μ - 2mm)
- D visible pores larger than 2mm (vugs or fractures)

Combinations of letters may be used where more than one pore size is present.

An Archie classification consists of at least matrix number and at least one visible letter. For example:

- Dense partly chalky mudstone with few visible pores (I/II - A/B)
- Oolithic grainstone, well cemented, no visible porosity (I - A)
- Sucrosic crystalline dolomite, with local patches of anhydrite cement, visible pores (I/III - C)

The simplest and most common classification of porosity is, either primary or secondary.

- **Primary Porosity** - formed as an intricate part of the rock fabric. Interparticle porosity (between grains or crystals) and voids within skeletal particles and growth structures, are the most common primary porosity seen in cuttings samples.
- **Secondary Porosity** - formed secondary to the rock fabric. Fractures, fissures and vugs are the most common types of secondary porosity. This type is not usually seen in cuttings, but may be inferred (ROP, torque, lost circulation, crystal growth, etc.).

A generalized porosity description for carbonates can include the terms and modifiers of Choquette & Pray (see Figure 2-6).

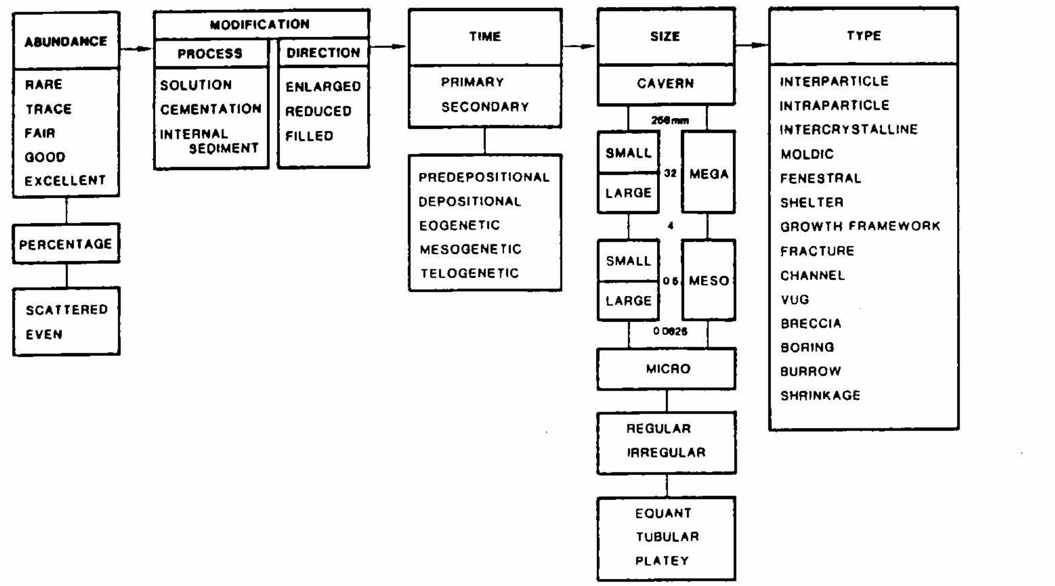



**Figure 2-6: Porosity Descriptions (after Choquette & Pray)**

### Accessories or Inclusions

Minor accessories in carbonate rocks are commonly detrital or diagenetic products of terrigenous rock fragments contained within the original sediment, mixed with the carbonate minerals.

The presence of elemental sulfur and metallic sulfides as concretions or staining on fractures is common. It is also an indication of anaerobic conditions, and possible hydrogen sulfide hazards. Accessory silica (chalcedony, chert and crystalline quartz), if in large amounts can lead to drilling difficulties. Fossils, in addition to being a major component, are often significant accessories. The presence and abundance of fossils should be noted, with an identification of phylum (or class) if possible.

## Chemical Rocks

Chemical rocks are described in the same manner as clastic and carbonates. The twelve parameters in the description format, used with various modifiers will complete the description.

### Chert

During drilling operations, the most easily recognized characteristic of chert is its tremendous hardness (7 on the Mohs scale) and glass-like brittleness. Drilling into a chert with a tri-cone bit (especially a mill-tooth bit) will result in an almost complete halt in the drill rate, with much bit-bouncing and vibrations. If the bit teeth do not penetrate the chert, torque will be low, but if the chert is thin bedded or fractured, torque will become irregular as the bit “sticks and skips” over the surface.

Bedded cherts are usually evenly bedded, thinly laminated to massive (ranging in thickness from ten to hundreds of feet).

Color will be indicative of the environment of deposition. Diatomaceous and radiolarian cherts are black to dark gray (due to clay impurities), and spiculiferous cherts being light to medium gray with a brown to green tinge (due to large amounts of calcite).

Chert cuttings will be large, elongated, and bladed in shape, with fresh curved conchoidal fracture surfaces. By definition, it will be cryptocrystalline or microcrystalline and very hard. Abundant metal shavings will probably be included in the sample.

### Halite

When drilling massive evaporites, it is common practice to drill them with a salt-saturated or oil-based mud system. If this is done, then sample recovery will be good, and samples can be treated in a “normal” manner.

Thin or partially saline formations are usually drilled with a “fresh” water system. If this happens, most of the soluble materials will be lost to solution. When this occurs, secondary evidence of evaporites are:

1. An increase and smooth drill rate
2. Decreased volume of cuttings
3. Eroded or re-worked appearance of cuttings
4. Increased drilling fluid salinity
5. Increased drilling fluid viscosity
6. Decreased and smooth background gas
7. Salty encrustations on the surface of dried cuttings

Halite cuttings will show good cubic cleavage, and will normally be colorless to white, but often with a pink to red tinge. It will be recognized by its solubility and taste.

Thin beds of anhydrite or gypsum are usually present with halite. When thin beds of halite occur, they are normally present with red-beds or red clays.

### Anhydrite and Gypsum

Determination between anhydrite and gypsum is not always possible at the wellsite, but an attempt should be made. The similarities and differences are:

| Characteristic | Gypsum | Anhydrite |
|---|---|---|
| Formula | $CaSO_4$ x $2H_2O$ | $CaSO_4$ |
| Color | White, light to dark grey, red, blue, yellow, brown | White, pale grey, red |
| Structure | Selenite crystals, glassy, slightly flexible,fibrous structure, Satin spar, fibrous to lacy, pearly, Massive, fine grained, subvitreous to dull luster, Spongy,white,soft | Fibrous,parallel & radiate structures, fine grained<br><br>Amorphous, fine-grained, massive but cleavable |
| Luster | Pearly, earthy, subvitreous | Pearly, greasy, vitreous |
| Hardness | 1.5 - 2 on the Mohs scale, can be scratched by a fingernail | 3 - 3.5 on the Mohs scale, can be scratched by a brass pin |
| Density | 2.30 - 2.37 g/cc | 2.9 - 3.0 g/cc |

Even if discrimination between the two is not entirely possible, the presence of a sulfate mineral can be confirmed using HCl. Limestone will effervesce, while anhydrite or gypsum will not.

Confirmation can be obtained by crushing a dried sample into a fine powder, place the powder in a watch glass with HCl and heat it slowly. The powder will slowly dissolve, and when slowly cooled, gypsum/anhydrite will precipitate as accicular crystals around the edge of the watch glass.

Barium chloride, used with caution, will also determine sulfate presence.

1. Place several cuttings in a cut bottle and fill with distilled water.
2. Agitate and pour off water. Refill and repeat.
3. Half fill with distilled water and add three drops of HCl and agitate.
4. Add two drops of barium chloride.

A pearly white discoloration will confirm the presence of gypsum or anhydrite.

## Carbonaceous Rocks

Though not a common rock type, coal/lignite is included because many carbon-bearing rocks will be drilled during the search for hydrocarbons. In addition, coal seams provide useful marker beds, and can be readily detailed using the drill rate. In gas analysis, they give well defined methane peaks. Their low density, low porosity and high resistivity is evident on wireline logs.

Coal seams can be greater than six feet (2 meters) thick, and can cause drilling and logging problems in directional wells.

In geologically young deposits, lignite (brown coal) is found and can be identified from the traces of vegetal matter in the rock. Though very easy to detect in cuttings samples, it can be easily confused with the lignite used as a mud additive.

## Igneous Rocks

Igneous rocks are not usually of major significance in petroleum geology, but stopping a well in a dike or sill, and failing to test the sedimentary rock below, can be as great a problem as drilling thousands of feet into a bottomless granitic pluton.

Igneous rocks are very important in the drilling of geothermal wells.

Many research wells drill into igneous rocks. The Siljan Ring well in central Sweden, wells on the San Andreas Fault, the KOLA SG3 in Russia, and the KTB well in West Germany are a few examples.

### Plutonic Intrusive Rocks

#### Granite

No attempt will be made to distinguish between the numerous members within the granite family. Granite, for these purposes, is always holocrystalline (crystals being visible under the microscope). The essential minerals are orthoclase (pink feldspar) and quartz. By definition, to be a granite, the feldspar and quartz crystals must be interlocking.

#### Diorite

These rocks are the intermediate between the acidic (granite) and basic (gabbro) ends of the igneous rock classification. Diorites tend to be grey in color and deficient in quartz. The essential minerals are plagioclase feldspar (oligoclase) and hornblende. Interlocking crystals are a must.

### Gabbro

Gabbros are the mafic end of the igneous rock classification. They are dark-colored, and are commonly composed of plagioclase feldspar (anorthite) and pyroxene, in varying amounts. They are iron-rich with high specific gravities (> 3.0) and can be magnetic.

## Dikes and Sills

These are intrusives radiating away from the magma chamber. The two end-members are aplites (granitic affinities) and diabases (gabbroic affinities) will be mentioned. Pegmatites are also included.

### Aplite

These are fine-grained, pink, acidic intrusives originating from a granitic magma. The pink color is due to a large (> 50%) orthoclase feldspar content. The fine grained (aphanitic) texture is a function of rapid cooling.

### Diabase

These are fine-grained, black, basic intrusives originating from a gabbroic magma. The dark color is due to pyroxene and dark calcic plagioclase feldspars. Rapid cooling produces the aphanitic texture.

### Pegmatites

These are acid rocks which are late stage differentiates resulting in a mono-mineralogic rock with extremely large crystals. Common pegmatite forming minerals are muscovite, quartz and orthoclase feldspar.

## Volcanic Rocks

Volcanic rocks are divided into two major types: extrusives and pyroclastics. Extrusives are flows of molten material (lava) spilling from a volcanic vent at the surface. Their chemistry will be similar to the parent magma; 1) Rhyolite (derived from a granitic magma), 2) Andesite (derived from an intermediate or dioritic magma), and 3) Basalt (derived from a gabboric magma), are the most commonly encountered.

The most commonly encountered pyroclastic rock are tuffs (volcanic ash).

### Rhyolite

This is a pink rock which is easily mistaken for aplite in cuttings, since they are derived from the same parent magma. They are identical with respect to their chemistry and mineralogy. The key distinguishing characteristic is texture. Rhyolites are prophyritic (large differences in the sizes of the various minerals making up the rock). Because extrusives are relatively slow-cooling, the ground-mass of the rhyolite will be fine grained, but late stage crystals will still have a chance to grow (termed phenocrysts).

Since it is a flow structure, mineral alignment (feldspars) will be present. Though difficult to see in cuttings, it can be seen in cores or thin sections.

Vesicles are also common, occurring because of gas pockets in the rocks. They are spherical, and are frequently filled by silica.

### Basalt

Basalt is the extrusive equivalent of diabase. The distinctions between the two are the same as for aplite-rhyolite. Basalts are the most widespread rocks on earth.

Textures of basalts are similar to those of rhyolites. They are typically amygdaloidal (containing vesicles) which are commonly filled with quartz, carbonates or zeolites, precipitating from low temperature ground water. The vesicles tend to be larger than those in rhyolites. Alignment of minerals is pervasive in basalts.

### Andesite

Andesites are volcanic flows which are intermediate in composition between rhyolite and basalt. They are texturally similar to the end members, but are usually grey in color (lacking the pink orthoclase of rhyolites and the high content of mafic minerals in basalts). Most andesites are not derived from dioritic magmas, which they resemble chemically and mineralogically, but from the subduction of rocks along plate margins.

### Tuffs

Tuffs tend to be microcrystalline, white and massive, and usually require thin section work for a positive identification. Tuffs are essentially volcanic glass, which with geologic time devitrify (no volcanic glass is known to be older than the Eocene). Tuffs are commonly silicified, and can be mistaken for fine-grained orthoquartzite. There are three classes of tuffs: ash falls, ash flows, and water-laid. Bentonite is a variety of altered tuff.

## Igneous Rock Descriptions

Since igneous rocks are subdivided from acidic to ultrabasic, the first step is the determination of the amount of silica in the rock/cuttings. A chemical analysis is impossible at the wellsite, so a determination of the amount of “light” minerals will have to be sufficient. Under microscopic examination, the following proportions are used:

- acidic: more than 80% light minerals (including free quartz)
- intermediate: 60 to 80% light minerals

- basic: 20 to 60% light minerals
- ultrabasic: less than 20% light minerals

Quartz can be determined by its hardness, lack of color and greater transparency. If crystal form is developed, then the lack of cleavage will also distinguish quartz. Since the major “light” minerals will be quartz and feldspars, distinguishing the quartz content should be accomplished.

The Grain Size Comparator will allow crystal size determination. This is important when comparing different crystal sizes to a ground-mass.

Rock textures will assist in determining rock types. Textures such as “holocrystalline” and “porphyritic” have already been described.

Mineralogy of the rock/cuttings should be attempted. The following are common minerals found in igneous rocks:

- ***Quartz:*** determined by hardness, color, lack of cleavage
- ***Orthoclase***: determined by its reddish color (may range from flesh-tinted to brick red). It is insoluble in dilute HCl.
- ***Plagioclase***: determined by its greyish-white color. If striations are present, it may indicate albite twinning. It is slowly soluble in dilute HCl and will leave a cloudy suspension.

  Feldspars are generally seen to be semi-translucent to opaque, pale colored and having a dull porcelaneous luster. Even when weathered, the euhedral and subhedral laths are normally visible. Although fresh feldspars have a hardness similar to quartz, alteration usually leaves a softer crumbly surface or edge.
- ***Nepheline***: occurs as irregular grains with a white to smoky color and a vitreous to oily luster. It is readily soluble in dilute HCL, leaving a residue of colloidal silica. It will occur in substantial quantities in dark-colored intermediate rocks.
- ***Leucite***: occurs as grey-white, vitreous trapezohedra. It is brittle with conchoidal fracture, and occurs only in extrusive rocks. It dissolves in dilute HCl, leaving no residue
- ***Biotite***: occurs as black to dark grey flakes. A common mineral in acidic and intermediate rocks

Other important minerals are pyroxenes (the major ferro-magnesian minerals in basic and ultrabasic rocks), hornblende and sodalite (bright to dark blue, having a strong fluorescence).

When drilling in areas where igneous rocks are possible, the Wellsite Geologist must work with an open mind and expect the unexpected.

Volcanic rocks appear in many places around the globe, and the possibility of drilling igneous rocks should not be dismissed.

When drilling igneous rocks, a standard mineralogy text would be useful.

## Metamorphic Rocks

Metamorphism is divided into two divisions: 1) contact metamorphism, which includes those reactions in close proximity to a specific source of temperature and pressure, and 2) regional metamorphism, which is associated with major tectonic events.

Both types act upon similar pre-existing rocks, under similar temperature and pressure conditions, thus producing similar metamorphic rock types. Most discussions of metamorphic rock proceed from metamorphic facies developed under different pressures and temperatures.

### Zeolite Facies

This represents metamorphic reactions at the lowest temperature and pressure. It bridges the gap between diagenetic changes in the rocks to true metamorphic reactions. This facies covers the temperature range at which hydrocarbon molecules break down. Temperatures within this facies begin at ± 100°C and continue to ± 350°C.

### Greenschist Facies

This represents the most voluminous and common of all metamorphic rocks. It takes its name from its schistose texture and the green color of chlorite, epidote and actinolite (all common in the facies). Temperatures range from 350°C to 500°C. Three sub-facies are recognized based on the key minerals chlorite, biotite and garnet (going from lowest to highest temperatures). An easy index to this facies is the mineral epidote, which occurs at 350°C.

### Amphibolite Facies

Hornblende is the most common amphibole, and the appearance of metamorphic hornblende is the chief criteria of this facies. Amphibolites can be derived from pre-existing shales or basalts, but this cannot be determined at the wellsite. Amphibolites are commonly 80 to 90% hornblende, exhibiting lineations of black, prismatic crystals. Identification of metamorphic hornblende signals the economic basement (500°C).

### Granulite Facies

At 600°C and above, all rock types begin to melt and produce gneissic rock types. Mafic minerals such as biotite and hornblende commonly become segregated and exhibit flow structures and alignment. The mineralogy of this facies approaches that of granite.

## Metamorphic Rock Descriptions

Metamorphic textures and mineralogy develop progressively over several hundreds of feet/meters of drilling. Without careful examination by the Wellsite Geologist, and the recognition of the subtle changes in mineralogy and texture, much time and money can be wasted by drilling past the economic basement.

Since the change from sedimentary to metamorphic rocks is transitional, even the most experienced geologist will require time and footage to recognize and confirm the event. Experience shows that the majority of footage cut of metamorphic rocks is of low metamorphic grade which was not recognized, simply because the geologists at the wellsite did not consider the possibility.

The texture of a metamorphic rock is a unique product of its mineralogy and metamorphic conditions. Even if a complex assemblage is not identifiable at the wellsite, a combination of minerals and textures should allow the rock to be characterized.

## Textures

### Schistose

Grains are platy to elongate and oriented parallel or subparallel; foliated if fabric is planar or lineated if the fabric is linear; micaceous and tabular minerals are common and usually well enough developed to be visible. Common rock types are:

1. ***Schist*** - grains can be seen without using a microscope
2. ***Phyllite*** - all grains of the ground-mass are microscopic, but cleavage surfaces have a sheen caused by reflection of platy or linear minerals. Commonly corrugated.
3. ***Slate*** - grains are microscopic, very cleavable, usually tougher than shale.

### Granoblastic

Grains are approximately equi-dimensional, platy and linear grains are randomly oriented. No foliation is developed. Common rock types are based on compositional type (i.e. Quartzite, Marble).

### Hornfelsic

Grains are irregular and generally interlocking, and microscopic. They exhibit a hackly fracture, are very hard and fresh surfaces show a sugary coating which will not rub off. Rocks of this type are called “Hornfels”.

### Gneissic

Platy or linear grains subparallel, but so subordinate or so unevenly distributed that the rock has only a crude foliation. Especially common in metamorphosed granular rocks. Common rock types are “Gneisses”.

### Cataclastic

Clastic textures resulting from breaking and grinding with little if any recrystallization. Characterized by angular, lensoid, or rounded fragments in a fine-grained and commonly streaked or layered ground-mass. The ground-mass is usually rock flour. Common rock type is “Mylonite”.

## Sample Contamination

Samples can be contaminated from a variety of sources. The most common source of contamination is from cavings (rock fragments that come from previously drilled sections). They are recognized by their large size and often splintery nature and are commonly seen after bit trips, wiper trips and periods when circulation has been stopped. These can be a serious problem if the wellbore is unstable. Their presence may also be an indicator of poor drilling practices such as circulating with an excessive flow-rate or rotating too fast. Recycled cuttings may be present if the solids removal equipment (shakers, desanders and desilters) is not efficient enough to remove them from the drilling fluid.

Mud chemicals will be present in samples if the mud is poorly mixed. Lignosulphonate can resemble coal/lignite. Lost circulation zones will result in contamination by lost circulation material (LCM) such as nut-plug, mica and cellophane. Beware of mud additives which give natural or cut fluorescence (i.e. “Idex”). These additives can get into fractures and pore spaces of the cuttings and lead to erroneous show interpretations.

Cement will be present in the samples after casing shoes, sidetracks and cement plugs. It can be recognized because it looks like siltstone and it's reaction with phenolpthalein, which will turn cement purple (due to cements high pH).

Metal can also be found in samples (common after casing shoes) due to the scraping effect of drill pipe on the inside of the casing. This is especially true in deviated wells (drillpipe protectors can be used to help reduce this problem). Excessive bit wear can also result in metal in the samples and should be reported to drilling personnel (especially if it coincides with slow drilling or excessive torque in the drillstring). Casing paint is a black bituminous substance that resembles bitumen and always check to see if newly coated drill-pipe is being used, or if the pipe has been stored a long time. Pieces of rubber can be found in samples from cement plugs (top or bottom plug during a casing cement job), pipe protectors and centralizers.

| Name | Formula/Constituents | Function | Contamination Properties |
|---|---|---|---|
| Barite | $BaSO_4$ | Increasing mud density | May contain fine sand.<br>Confusion with natural barite |
| Bentonite | Monmorrilonite Clays | Filtration Control | If poorly mixed, confused with natural monmorrilonite clays |
| Cement | Various | Various | Looks like siltstone<br>Identified by phenophthalein |
| Asbestos | Shredded Asbestos | Viscosifier for water-based muds | Mistaken for natural asbestos |
| Defoamers | Various - usually mixed with diesel | Reduce foaming in water-based muds | Spurious fluorescence and gas readings |
| Diesel Oil | Diesel | Lubricant, Solvent, Anti-corrosive | Bright blue-white fluorescence and high background gas |
| LCM | Micas, walnut shells, wood, cellophane, etc. | For prevention or cure of lost circulation | After several circulations can be mistaken for lithologies. Can usually be “panned” off sample. |
| Lignosulfonates | Metallic sulfonate produced from lignin | Dispersant and fluid control | Mistaken for natural lignite |
| Idex<br>Gillsonite | Asphaltic product<br>Solid Hydrocarbon | Inhibits fracturization and fluid loss | no natural fluorescence, but is black and bituminous, and gives a bluish-white to milky yellow cut fluorescence |
| Oil Muds | Various | Protection of formation, water contamination control | See *Appendix C, Drill Returns Logging Manual*, for oil mud logging procedures |
| Pipe Dope | Heavy oils/grease | Lubricant for tool joints | Bright to dull fluorescence varying between types |
| Pipe lubricants | eg. Coat 415® usually amines | Lubricant for stuck pipe | Spurious gas readings and fluorescence |
| Soltex | Dried asbestos powder | Shale control and fluid loss control | Yellow natural and cut fluorescence |
| Stearates (usually Aluminium or Potassium) | $(CH_3(CH_2)_{16}(C0O)_3)$ | Defoamer in water based muds | Causes spurious gas readings |

**Figure 2-7: Common Contaminants Found At The Wellsite**

## Shipping Samples

Drill cuttings samples are collected by the mud loggers, at specified intervals, for shipping and post well evaluation. Several reasons for this service are:

- Paleontological/Palynological analysis
- Geochemical analysis
- Oil company partners
- Governmental requirements
- Future reference/library samples

These samples are caught at regular intervals, which is stated in the drilling prognosis, but is of course, subject to change. Under no circumstances should the mud loggers neglect this responsibilities. If they feel that the sampling interval cannot be complied with (i.e. small intervals and a high drill rate), then arrangements should be made to have a “sample catcher” sent to the rig, or have the intervals increased. So called “double bagging” should not be permitted, as this can cause misinterpretations by the geochemist or micropaleontologist.

If the drill rate slows down, then the sample interval should be shortened to assure a representative sample is collected. Several other times the sample interval can be shortened or spot samples collected are:

- During coring - 1 foot (0.5 meter) samples are collected
- Areas of geologic interest
- Changes in the drilling parameters (drill breaks/reverse drill breaks, torque changes, etc.)
- Changes in the drilling fluid parameters (viscosity changes, cut mud density, chloride changes, etc.)
- Changes in the gas content (amount or composition)

## Sample Types

The mud logger will normally have to collect and ship several “types” of drill cuttings samples.

### Wet Samples

Wet samples are the samples collected off the collection device at the shale shaker. Normally the drilling fluid is not rinsed off. The sample is placed in a plastic liner, then into a cloth sack.

The sack should be marked using waterproof ink, with:

- Oil Company's Name
- Well Name
- Sample Interval (both top and bottom)

It is wise to put this information on the sack's tag also, because though the ink may be waterproof, it is not oil proof (and may become obliterated when oil-based mud samples are caught). The sample bags should be filled as fully as possible. If no samples are caught, due to lost circulation, then the sample bag should be properly labelled with “no returns” or “no sample”. The sample sacks are normally shipped in large boxes or burlap sacks. These too should be properly labelled with:

- Oil Company's name
- Well name
- Depth Interval
- Shipping/Destination Address

The shipping sacks or boxes should not be over-filled, because they will be too heavy to lift safely. When boxes are used, wrap them in a plastic sack to prevent leakage during transport.

A record of the shipping details/manifest should be kept at the wellsite and placed in your files.

### Dry Samples

Dry samples are obtained from the washed samples collected from the 80-mesh sieve. Again, the interval and number of samples will be determined by the oil company. A heat source is used for drying purposes. Several precautions when drying samples are:

- DO NOT oven dry oil-based mud samples
- Do not over-dry samples, because they will burn (the burning can be mistaken for oil staining)
- Clay samples should not be oven dried - only air dried
- Be careful when touching the hot sample trays
- Allow the dried samples to cool before placing them into the sample envelopes
- Remember the correct order of the samples when many are placed under the heat source

The samples envelopes and shipping boxes should have the same labelling as the wet sample bags.

It is a good idea to keep a small portion of the dried samples available for viewing. This will allow the Wellsite Geologist to quickly view long intervals, and is useful in identifying subtle changes in lithology, color, oil staining and grain size. Plastic “samplex” trays are ideal.

## Geochemical Samples

These samples require special treatment. A bacteriocide (i.e. Zepharin Chloride) is necessary to prevent the growth of bacteria which can form additional gas. The samples are normally sealed at the wellsite, and shipped separately.

These samples are often taken over larger intervals and are composites of unwashed wet samples. When collected and placed in a metal or plastic container, fresh water and the bacteriocide are added, leaving approximately 3 cm of air-space for gases to collect. Once sealed, they are best stored upside down in their shipping containers.

As with wet sample sets, the geochemical shipping containers should have plastic lining to prevent leakage during transport. Many airlines and transport companies will not carry leaking containers, and may even fine the oil companies if leakage occurs during transport.

Chapter 3

# Evaluation Of Hydrocarbon Shows

The Wellsite Geologist is expected to know how to evaluate and interpretate hydrocarbon shows. Even though it may be the mud loggers responsibility to describe and evaluate hydrocarbon shows, the Wellsite Geologist must understand the evaluation procedures to ensure adequate quality control over the evaluation processes. In instances when mud logging operations are not applicable, the Wellsite Geologist will have to perform hydrocarbon show analysis by themselves.

Based upon pre-well information, the Wellsite Geologist should have an idea of the type of hydrocarbons expected from the well (gas, condensate, oil, etc.). When applicable, this knowledge should be shared with the mud loggers to ensure those formations in the prognosis are not missed.

## Oil Shows

Evaluation of oil in the drill cuttings (and drilling fluid) begins with inspection of those samples under the microscope and inspection in the ultraviolet-light box. Tests and visual inspection should be performed on the mud, unwashed and washed bulk cuttings, as well as individual grains.

### Hydrocarbon Odor

This may be the first indication of the presence of oil. Most people can readily tell the difference between a “heavy” oil odor and a “light” diesel odor. Any petroliferous odors present in the mud or cuttings, should be described as faint, moderate or strong.

### Oil Staining

Any stain or coloration that is not superficial, except in the case of oil from fractured reservoirs, warrants checking with a fluoroscope or solvent test. The amount, degree and color of the staining should be noted, such as:

- no visible oil stain
- spotty oil stain
- streaky oil stain
- patchy oil stain
- uniform oil stain

Include the relevant color and fluorescence intensity. The color of the staining can be related to the oil's gravity, where lighter colored stains are indicative of high gravity oils and darker stains indicative of lower gravity oils. A black asphaltic residue is indicative of dead, residual oil lacking volatile components.

Sample chips that bob to the top in water or acid should be checked with a fluoroscope. This bobbing may be due to a surface coating of oil on the cuttings, and a check should be made to see whether oil staining goes right through the chips. Remember oil-base muds (OBM) will cause the sample chips to be oil soaked.

## Natural Fluorescence

At the microscope, the geologist should select those cuttings that have visible oil staining and place a representative selection on a spot plate. They are then transferred under a UV light where they can be inspected for fluorescence and solvent cut.

The intensity and color of oil fluorescence is a most useful indication of oil gravity and mobility. Decreased intensity and darker colors commonly accompany decreases in API gravity. Water-wet or residual oils, which tend to be poorer in the lighter, more volatile hydrocarbons, will have a fluorescence color representative of their gravity, but will commonly be paler in color and have a less intense fluorescence.

In all fluorescence tests, it is important to observe a fresh surface. Since fluorescence can be caused by certain minerals or contaminants (such as pipe dope) care must be taken not to confuse these with formation hydrocarbons. Minerals fluorescence will not leach in a solvent, therefore no cut fluorescence will be observed. As mentioned above, the intensity of the fluorescence may yield important clues as to the fluid content of the rock. For instance, though a series of samples are uniformly fluorescent, a lessening of intensity may indicate; 1) a transition from oil to water producing zones or, 2) variable porosity/permeability with the same formation (i.e. chalky limestones).

When fluorescence is not attributable to minerals or contaminants in a sample, then this is taken as proof of oil being present in a rock, and allows for an estimation and description of the amount of oil in the cutting. Since the color of crude-oil fluorescence can be used to make a quantitative identification of the approximate API gravity of the crude, color description is important. Colors can range from brown to blue-white with a variety of colors and shades between. The darker colors (browns and oranges) are associated with the heavier crudes, the lighter colors are indicative of the lighter oils. Refined oils such as diesel and pipe-dope will give a bluish-white fluorescence. Very light oils or condensates and heavy tars may not fluoresce at all.

Experience shows the following rough fluorescence correlation:

- 2° to 10° non-florescent to dull brown
- 10° to 18° yellow-brown to gold
- 18° to 45° gold to pale yellow
- 45° and above blue-white to white

The degree of oil fluorescence should be immediately noted and described as:

| | |
|---|---|
| none | patchy |
| spotty | uniform/even |
| streaky | any combination thereof |

The color should be noted along with the percentage of the sample fluorescing, and the percentage of the reservoir rock fluorescing. The brightness of the fluorescence is important. Below the oil/water interface, the cuttings, while still carrying a lot of oil and gas, may show a marked change in intensity, the fluorescence becoming dull and losing its original bright sharp color.

Fluorescence checks should be carried out immediately on a sample. If the cuttings are left exposed to the atmosphere, the fluorescence tends to dull appreciably due to the loss of volatiles. This is accelerated under heat lamps and under the microscope lamp.

Along with the above description of fluorescence, a note should be made of how the fluorescence is distributed throughout the rock. In most cases the fluorescence will be found around the grains in the matrix of the rock, but in some areas the reservoir rock may be of such low porosity and highly fractured, that all the fluorescence and staining occurs along the fractures and often never enters the parent rock more than a few millimeters (if at all). This is often the case in fractured granite and highly fractured limestone/dolomite reservoirs.

Care is emphasized in this evaluation, as fracture porosity and permeability of the parent rock cannot be used in the determination of a field's producing capabilities. Production will be dependent upon the amount of fracturing present, its interconnection, and the amount of recrystallization along them. A better idea of the production possibilities can be estimated from taking cores.

Mineral fluorescence can be confused with hydrocarbon fluorescence. Remember, mineral fluorescence will not produce a “solvent cut”.

| Rock Type | Fluorescence Color |
|---|---|
| dolomite, sandy limestone | yellow, yellowish brown |
| some limestones | brown |
| chalk | purple |
| paper shale | yellow to coffee brown, grayish |
| fossils | yellow white to yellow-brown |
| marl, clay marl | yellowish to brownish gray |
| anhydrite | gray brown, grayish |

## Solvent Cut Fluorescence

The solvent cut is a valuable method in assessing fluorescence and allows deductions to be made of oil mobility and permeability. By removing the oil from the colored background of the rock cutting, the solvent cut also allows a better estimate of sample fluorescence.

The speed in which the solvent cut occurs (e.g. instantly for high gravity oils, more slowly for more viscous lower gravity oils, or irregularly streaming from limited permeability) also yields useful information.

If no cut can be obtained from a washed cutting, the test can be repeated on a drier or dried cutting, a crushed cutting or after application of dilute hydrochloric acid. This may produce the required cut and yields further evidence on permeability and effective porosity. After the solvent has evaporated, a residue of oil will remain in the spot plate, displaying the oil's natural color.

## Emulsion (Pop) Test

Examination of the mud and unwashed cuttings for oil may not be so discriminating as individual cuttings, but it can yield general information on oil type. Drilling mud can be poured into a dish and observed for fluorescence under a UV light. Oil may be seen “popping” at the surface. After adding 100 cc of water, the sample is observed again. This helps to lower the mud's viscosity and separates the mud and oil, allowing a small oil sample to be skimmed off the water surface. Finally the mud and water are stirred together, and the sample is left for 30 seconds or longer to allow all of the oil present to accumulate on the surface. If a high gravity oil or condensate is suspected, the sample should be observed throughout this period. Otherwise evaporation due to the heat of the UV light may lead to a pessimistic or false conclusion.

This procedure can be repeated with 200 cc of unwashed cuttings. In this case, working the sample with the fingers can help to free oil droplets. The droplets rise through the water and appear to pop on the surface as hydrocarbons are released.

Such oil effects observed from mud or unwashed cuttings under the UV light are commonly classified into five characteristic types:

Type 1: 1mm pops, scattered and few in number; this type is frequently associated with oil found in shale, along bedding planes, fractures, and sandstone containing very slight traces of residual oil.

Type 2: 2mm pops or larger, few in number commonly noted in large fractures and residual oil in sandstone; may be dull and streaky, associated with low gas readings.

Type 3: Pinpoints common, along with 2mm or larger pops; this type of fluorescence frequently observed from sections with fair amounts of oil.

Type 4: Common to abundant pinpoint; normally associated with good to fair show of oil.

Type 5: Abundant pops 2mm and larger, are frequently found associated with good shows. In higher gravity oil, the pops surface and spread rapidly. Gas can usually be seen escaping as the oil pops to the surface.

### Hydrocarbon Score Charts

Some mud logging companies use “score charts” to analyze oil shows. These score charts are very useful in standardizing shows between individuals and allowing everyone to rate a show in the same manner. An example of a score chart can be seen in Figure 3-1.

### Summary

In some geographical areas, horizontal wells are drilled along hydrocarbon-bearing formations (e.g. chalks in the Danish North Sea), and it is often left up to the Wellsite Geologist to get their “eyes-in” and evaluate the water saturations based on show evaluations. In these cases, a geologist must regularly view the samples and perform their own show evaluations (this is especially true during mud logger change-over, as each crew may view the shows differently). If FEMWD tools are used, the Sw estimations are easier, and the horizontal well can be kept in the zones of best porosity and lowest water saturations.

Once the Wellsite Geologist or the mud logger have fully described the show, it should be graphically displayed on the mud log and lithlog. The oil show description should include:

- The amount of free oil in mud
- Any petroliferous odor
- Visible staining: color, distribution
- Fluorescence: color, intensity, percentage
- Solvent cut: rate, color, intensity, residue

Salinity or conductivity measurements should be taken continuously throughout the show. Since most “shows” will begin with a drilling break, salinity samples can be taken prior to the show appearing at the surface. This will provide a background value, and the “show chlorides” can be judged from that background.

A “show report” (Figure 3-2) is usually prepared by the mud logger to accompany the mud log. In addition, the log is normally redrafted on an expanded (5-inch = 100 ft.) scale to better illustrate the show.

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Odor** | none | | trace | | faint | | fair | | strong | | | | |
| **Residue** | none | trace | | thin ring | mod ring | good ring | thick ring | thin film | | thick film | | | |
| **Cut** | no | 30 sec | cloudy | slow crush | slow | slow streaming | | mod strng | fair strng | immed strng | | | |
| **Fluorescence Intensity** | | very dull | dull | | moderate | moderate bright | | bright | very bright | | | | |
| **Fluorescence Color** | | brown | orange brown | orange | gold | yellow | yellow white | | white | blue | | | |
| **% Fluorescence** | | trace | 5% | 10% | 20% | 30% | 40% | 50% | 60% | 70% | 80% | 90% | 100% |
| **Color of Staining** | none | | black | | brown | | tan | | gold | | yellow | | |
| **Staining** | none | residual | | globular | | spotty | | streaky | | patchy | | | uniform |
| **% Staining** | none | trace | 5% | 10% | 20% | 30% | 40% | 50% | 60% | 70% | 80% | 90% | 100% |
| **Oil in Mud** | none | | rare | | trace | | moderate | | good | | abundant | | |
| **Cuttings Gas** | none | x0.5 | x1 | x1.5 | x2 | x2.5 | x3 | x4 | x5 | x6 | x8 | | |
| **Increase C2-C5** | x0.25 | 20 | 50 | 100 | 200 | 300 | 500 | 750 | 1000 | 1250 | 1500 | 2000 | 3000 |
| **C1 Increase** | trace | 50 | 200 | 500 | 1000 | 1500 | 2000 | 5000 | 7500 | 10000 | 15000 | 20000 | 30000 |
| **ROP Change** | 1 | x1 | x1.5 | x2 | x3 | x4 | x5 | x7.5 | x10 | x12 | x15 | | |
| **Points Awarded** | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |

**Figure 3-1: Hydrocarbon Analysis Score Chart**

Show rating is based on the summation of the points awarded for each show parameter, as follows:

| Rating | Points |
|---|---|
| Insignificant | (1-15) |
| Poor Trace | (16-30) |
| Trace | (31-45) |
| Good Trace | (46-60) |
| Moderately Fair | (61-75) |
| Fair | (76-90) |
| Moderately Good | (91-105) |
| Good | (106-120) |
| Very Good | (121-130) |
| Excellent | (>131) |

# EXLOG SHOW REPORT # 1

**OIL COMPANY:** Kinghurst Expl. Co. **WELLNAME:** Test Well #1 **LOCATION:** Offshore Gulf Coast

**DATE:** 9 Sept 1984 **TIME:** 19:15 **SHOW INTERVAL:** 8705 ft **TO** 8835 ft **(md)**
8705 ft **TO** 8835 ft **(tvd)**

**BIT SIZE:** 12.25" **MUD WEIGHT:** 10.5 ppg **WOB:** 30K lbs **LOGGING CONDITIONS:** Good during show. Some problems with cement prior to show interval.
**BIT TYPE:** HTC X3A **VISCOSITY:** 42 sec/qt **RPM:** 100
**HOURS:** 17.3 hrs **FILTRATE:** 35 cc's **PUMP PR:** 3000 psi
**FEET:** 274 ft **EST. PORE PR:** 10.7 ppg **PUMP SPM:** 98

| | ROP | TOT GAS | CUTT GAS | C1 | C2 | C3 | C4 | C5 | Chl | LITHOLOGY |
|---|---|---|---|---|---|---|---|---|---|---|
| PRIOR TO SHOW | 30 | 35 | 0 | 6500 | 600 | 0 | 0 | 0 | 1250 | Siltstone: tan-brn,firm,blky ctgs,calc tr pyr,foss,mnrl flor,no cut |
| DURING SHOW | 200 | 635 | 70 | 98500 | 30000 | 6000 | 1270 | 0 | 1400 | Sandstone: clr-wh,f-med grn,sbrnd-rnd, w srtd,w cmt,slightly calc,tr glau |
| AFTER SHOW | 40 | 37 | 8 | 6600 | 800 | 40 | 0 | 0 | 1300 | Shale: lt gy-gy,mod hd,blky-plty ctgs, ethy lstr,slightly calc,tr pyr,foram |

**OIL IN MUD:** 'abnt bk brn-blk free oil in mud
**FLUOR:** Yellow/Gold
**UNWASHED CUTT FLUOR:** Yellow/Straw
**WASHED CUTT FLUOR:** 70% Bright Yellow
**STAIN:** 50% light brown streaky stain

**SOLVENT CUT-FLUOR:** Yellow/White
**INTENSITY:** Bright/Intense
**TYPE & SPEED:** Normal cut & Fast/Streaming Cut
**NAT COLOR & RESIDUE:** Good light brown residue ring
**VISUAL POROSITY:** Trace of pin-point porosity

**CHROMATOGRAPH RATIOS:**

**GAS WETNESS RATIO (GWR):** 27.45 **LIGHT-TO-HEAVY RATIO (LHR):** 17.66 **OIL CHARACTER QUALIFIER (OCQ):** .211

**COMMENTS:** There was an abundant amount of black/brown oil slick to the mud. When placed in a blender after agitation, a strong oil/diesel odor was present. Very prominent brown streaks (stain) on cuttings 70-80% of all cuttings fluoresced w/60-70% of the mud fluorescesing. Possibility of a minor washout in sand.

**RATING:** Good medium gravity oil show . ( 8 ) **LOGGING GEOLOGIST:** Max Smith

Figure 3-2: Example of a Hydrocarbon Show Report

## Gas Shows

Gas readings are most commonly obtained from the mud system by placing a separator or gas trap in the ditch (possum belly) or flow-line. Extracted gas is drawn into the mud logging unit where it's contents are measured by a variety of gas detectors; usually a total hydrocarbon detector, a chromatograph, a $CO_2$ detector and a $H_2S$ detector. Total gas detectors that monitor for nitrogen, various sulfides and hydrogen may also be used.

The amount of gas recorded is dependent upon many variables, including;

- Volume of gas per unit volume of formation
- Degree of formation flushing
- Rate of penetration
- Mud Density and Mud Viscosity
- Formation pressure
- Gas trap efficiency
- Gas detector efficiency
- Variability of mud flow rate

Due to the variability of gas analysis they are generally used only in a qualitative manner. Comparisons to other wells can only be down when indications are similar (i.e. between wells drilled by the same rig, with the same gas trap/detector system and similar mud types).

Gas readings are used with reference to a “background level”. The gas readings are then displayed graphically on either the mud log and or the geologists striplog. This allows an easy evaluation of the relative amounts of gas recorded. Contractors usually record total gas as either a percentage, ppm or in the form of gas units. A gas unit may vary from 0.02% to 0.033% depending upon contractor. The use of percent or ppm allows for better comparison between wells and contractors. Chromatographic analysis of the gas allows a breakdown into the relative proportions of methane (C1) through pentane (C5) and occasionally higher.

A understanding of the mud logger's gas detectors is important when reviewing gas data. The equipment between companies does differ. For example, some companies use chromatographs that do not measure the pentanes (C5), which could be important if the geologist is correlating with another mud log containing C5's.

Gas detectors may be of two types, an older catalytic (CCD) variety or the more modern FID. type. CCD detectors use a catalysis approach (that is the catalytic oxidation of gas upon a filament in the presence of air), while the FID use flame ionization (the ionization of a sample into charged hydrocarbon residues and free electrons by combustion). The type of equipment used should be known by the geologist as the two methods are affected differently when non-hydrocarbon gases are present.

The catalytic detectors upper limit of sensitivity is approximately 9.5%. At this point not enough oxygen is available for catalysis. A “negative” response occurs in the presence of $CO_2$, and the detector is affected by large quantities of nitrogen. Variations in temperature also cause a thermal drift of catalytic detectors. FID detectors are not affected by quantities of nitrogen, $CO_2$ or temperature variations.

To assist in post-well evaluation, the Wellsite Geologist should ask the mud loggers to note the type of gas detection equipment on the mud log. In addition, establish with the client how produced gases (i.e. connection and trip gases) are to be reported. For example, will they be reported as percent above background gas or as a total percentage.

## Gas Show Evaluation

As mentioned earlier, many factors affect the amount of gas recorded at the surface. Prior to discussing these at length some definitions are necessary.

***True Zero Gas*:**
The value recorded by the gas detectors when pure air is passed over the detection block (generally done during calibration). To ensure a stable zero mark, the detectors should be zeroed prior to drilling, at casing points, logging points, etc.

***Background Zero Gas*:**
The value recorded by the gas detectors when circulating, off-bottom, in a clean, balanced bore hole. Any gases monitored will be from contaminants in the mud or from gas recycling. This value is the baseline from which all gas readings are referenced for the striplog and mud log, but not plotted on the logs. This value will change with respect to changes in the mud system (adding diesel) and hole size, and should be re-established periodically.

***Background Gas*:**
This is the gas recorded while drilling through a consistent lithology. Often it will remain constant, however, in overpressured formations this value may show considerable variation. This is the gas baseline which is plotted on the striplog and mud log.

***Gas Show*:**

This is a gas reading that varies in magnitude or composition from the established background. It is an observed response on the gas detector and requires interpretation as to the cause. Not all gas peaks are from drilled formation, some may occur as post-drilling peaks.

***Connection Gases*:**

Gas peaks produced by a combination of near-balance/ under-balanced drilling and the removal of the ECD by stopping the pumps to make a connection. They are often an early indicator of drilling overpressured formations. These should be noted, but not included as part of a total gas curve.

***Trip Gases*:**

Gas peaks recorded after circulation has been stopped for a considerable time for either a bit trip or a wiper trip. As with connection gases, substantial trip gases can indicate a near balance between the mud hydrostatic pressure and the formation pressure, they should be recorded but not included as part of a total gas curve.

Like other logs, the mud log is a depth-related plot displaying certain physical characteristics of the formations being drilled. In the mud log's case, gas curves are changes in the concentration and composition of formation hydrocarbons. Like other logs, there are baselines or thresholds values, from which deviations may indicate significant events. One such baseline is gas present in normally pressured formations. There may be significant contributions by extraneous factors and the baseline itself may vary (in laminated formations it may oscillate to extremes), but it will provide a standard upon which events will be judged.

It is essential that absolute magnitude not be the only basis upon which gas show evaluation is made. The magnitude of a gas show is quantitative only to the air/gas sample obtained and measured at the detector. In correlating gas shows between different wells (especially where a change of rig or engineering approach is involved), the major parameters are curve profiles and relative compositions. As with the correlation of wireline logs, care should be taken to match up overall curve character and not just individual high and low values. Individual values are never reproducible and extremely high values should always be suspect, and are of little “correlative” use.

Logs showing a difference of several orders of magnitude in gas concentrations may be easily correlated by overlaying gas curves and recognizing significant peaks or variations in the form of the curve. Similarly, the significant event may be the appearance of a new component or a notable change in the relative concentration of two or three compounds.

At no time should the absolute magnitude of a gas show be taken as a basis for any quantitative statement. As stated earlier, no gas show should ever be considered in isolation. Reference should always be made to the pre-existent background value.

The gas phase at surface may not, and probably will not, have the same composition as the gas phase in-situ. It will nevertheless reflect the overall hydrocarbon composition (i.e. liquid and gas) of the reservoir, and chromatographic analysis can be used by skilled log interpreters as an important key to evaluation. Again, it is not simply the magnitude of gas shows, but their relative composition linked with all other log parameters which is the key factor.

In addition to the conventional log presentations of gas show data, certain mathematical treatments are available by mud logging companies as an aid in interpreting gas shows. Although some of these are attempted normalization (adjustments of the Total Gas values for the normalizing of known downhole effects), most are treatments for chromatographic analyses in order to determine characteristic responses typical of known hydrocarbon types.

## Gas Normalization

The quantification of gas shows is unattainable with current mud logging technology. The many in-situ and drilling variables are almost impossible to calculate during initial evaluation. In-situ variables include porosity, relative permeability, gas saturation, temperature, pressure, solubility and compressibility of the gases. Once penetrated by the drill bit, other variables come into play, such as flushing, drill rate, pump rate, hole size, rock and gas volume, differential pressure and temperature, phase changes and surface losses.

Normalization is the mathematical treatment of parameters affecting gas shows. Attempts have been made to cover all the downhole variables, such as saturation, temperature, pressure, etc. however, for truly accurate results by these methods, wireline log evaluation must be made first to arrive at a “safe” figure. Gas normalization does not try to cover surface losses, due to the great variations in flow-line and ditch geometries, flow rates and gas trap efficiencies (though studies have been made to determine gas trap efficiency). The most common form of normalization involves correction for drill rate, hole size and pump rate because these parameters are continuously monitored while drilling and can be immediately entered into normalization equations.

The main area of disagreement has been "What to normalize the readings to?" Ideally, there should be a universal set of ideal parameters for hole size, drill rate and flow rate. In reality, an ideal situation for one area may not be ideal for another. The basic normalization formula is:

$$G_n = G_d \times \frac{ROP_n}{ROP_o} \times \frac{\frac{\pi \times d_n^2}{4}}{\frac{\pi \times d_o^2}{4}} \times \frac{Q_o}{Q_n}$$

where:

| | |
|---|---|
| $G_n$ | = Normalized Gas (%EMA) |
| $G_d$ | = Ditch Gas Reading (%EMA) |
| $ROP_n$ | = Normalized Rate of Penetration (ft/hr or m/hr) |
| $ROP_o$ | = Observed Rate of Penetration (ft/hr or m/hr) |
| $d_n$ | = Normalized Bit Diameter (in or mm) |
| $d_o$ | = Observed Bite Diameter (in or mm) |
| $Q_n$ | = Normalized Flow Rate (gal/min or $m^3$/min) |
| $Q_o$ | = Observed Flow rate (gal/min or $m^3$/min) |

The "normal" parameters are selected on a regional or field basis which represent average or typical values while drilling through pay zones in the basin. The formula is then reduced and a "constant of normalization" is determined from the normal parameters.

For example:

| | |
|---|---|
| $ROP_n$ | = 60 ft./hr |
| $d_n$ | = 12.25 inches |
| $Q_n$ | = 600 gpm |

The gas normalization formula then becomes:

$$G_n = G_d \times 15.00625 \times \frac{Q_o}{ROP_o \times d_o^2}$$

The formula will produce normalized results that are corrected for well-to-well variations in the drilling program, and comparable in magnitude to the uncorrected ditch gas readings previously used in the field.

## Gas Ratio Analysis

The comparison of relative concentrations of the various hydrocarbon species seen in a chromatogram ($C_1$ - $C_5$) often has diagnostic value in qualitatively estimating the type and quality of a petroleum reservoir. Such a comparison has also been useful in stratigraphic correlation, where a distinct and characteristic hydrocarbon boundary may be recognized, even when no lithological facies boundary is evident.

The study of relative concentrations of light alkanes has been done by various people to evaluate maturity levels and migration modes of petroleum reservoirs. Studies of n- and iso-heptane ratios have been conducted to determine maturity and thermal history classifications of petroleum. Ratio studies of $C_2$ - $C_4$ and especially the butane isomers have been used to determine the effect of diffusion in primary migration and the possible maturity trends shown by theses studies.

These studies, however draw on data not readily available in normal wellsite logging, and practically all gas ratio studies performed at the wellsite are used to determine the type and quality of petroleum reservoirs. Such studies are mathematical treatments of the hydrocarbon species ($C_1$ - $C_5$) using relative concentrations such as $C_2/C_1$, $C_3/C_1$, etc. Plots from these studies will often yield distinctive “character” or “events” not always immediately evident from the chromatogram itself.

Two such ratio methods used are the “Rectangular Plot” and the “Triangular Plot”. Though originally designed for steam-still reflux mud or DST samples, then have been adapted for gas trap readings.

When using either plot, the following corrections must be made:

- Removal of all contamination gas readings, such as diesel, trip gas, connection gas, recycled gas
- Correction for background gas. The relative concentrations must be read above background gas
- More than one reading must be done to have any interpretative value

## Rectangular Plots

The rectangular plot uses the ratios $C_1/C_2$, $C_1/C_3$, $C_1/C_4$ and $C_2/C_3$ (or $C_1/C_5$) and plots the results on a semi-logarithmic grid (Figure 3-3). Values of these ratios are allocated to potential productivity, where:

| Ratio | Oil | Gas | Unproductive |
|---|---|---|---|
| $C_1/C_3$ | 2 - 10 | 10 - 35 | < 2 and > 35 |
| $C_1/C_3$ | 2 - 14 | 14 - 82 | < 2 and > 82 |
| $C_1/C_4$ | 2 - 21 | 21 - 200 | < 2 and > 200 |

Several “rules of thumb” for the rectangular plot are:

- Productive dry gas zones will yield mainly (or only) methane. However, abnormally high ratios may indicate gas in solution in a water zone.

- If $C_1/C_2$ falls in the oil section, but $C_1/C_4$ is high in the gas section, the zone may be non-productive.
- If any ratio is lower than the preceding ratio, the zone is probably non-productive.
- If $C_1/C_4$ is lower than $C_1/C_3$, the zone is probably water wet.

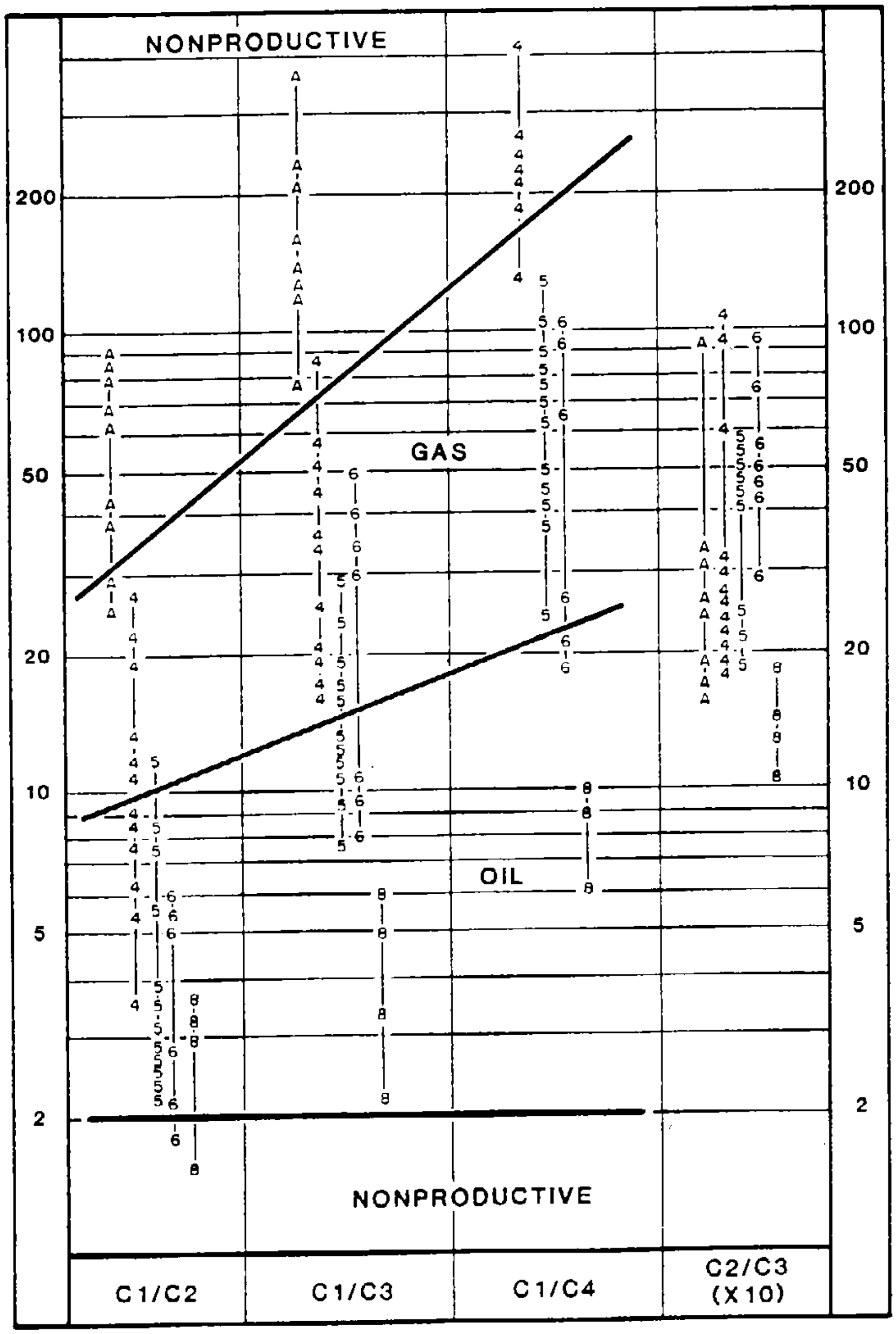



**Figure 3-3: Rectangular Gas Ratio Plot**

When plotted, the results tend to be inconclusive and a careful review of all log information can yield a more definitive evaluation. In practice, this type of plot can be useful as an illustrative tool and as one component in a complete evaluation.

### Triangular Plots

The triangular plot (Figure 3-4) requires the calculation of the ratios $C_2$, $C_3$ and $nC_4$ to the total of all gases detected (expressed as a percentage). Lines representing those percentages are then drawn on a triangular grid. As with the rectangular plot, all gas percentages are taken above background.

- If the apex of the triangle is up, gas is indicated - the smaller the up-apex triangle, the more water wet the gas.
- If the apex is down, oil is indicated - the larger the down-apex triangle, the heavier the oil.
- If the intersection of the lines between B to B' and A to A' occurs within the plotted ellipse, the zone is considered to be productive.

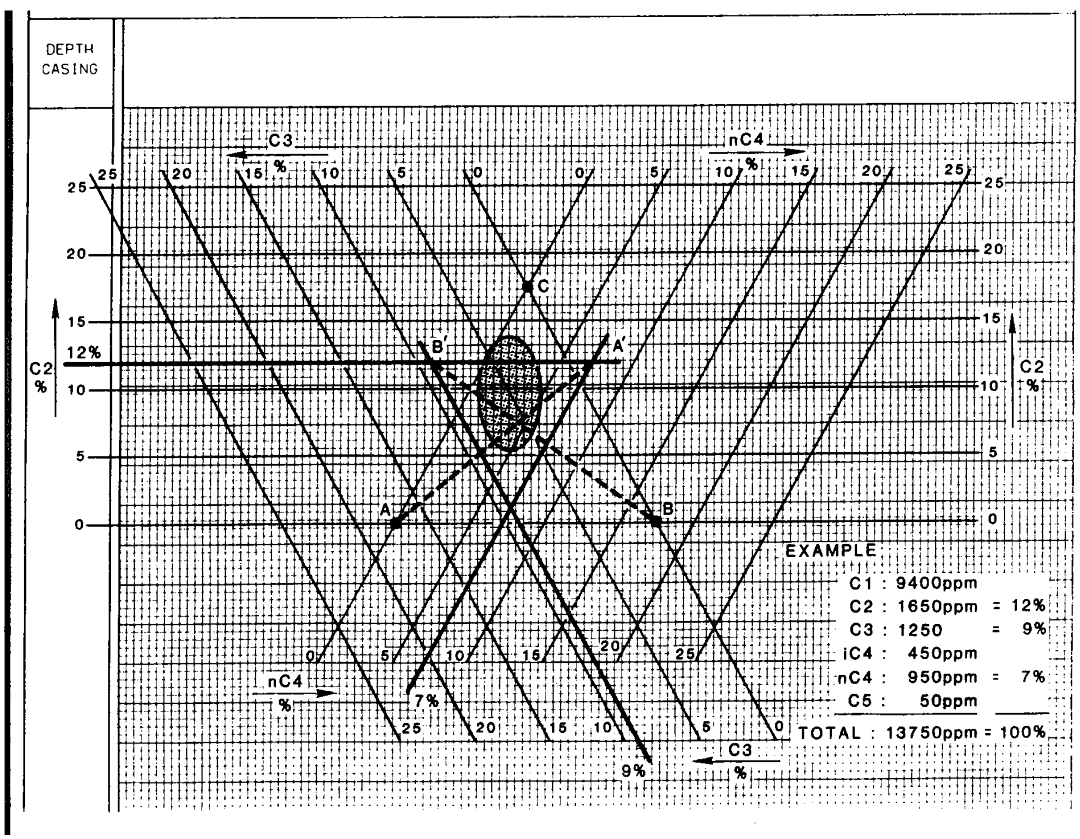



**Figure 3-4: Triangular Gas Ratio Chart**

## Baker Hughes INTEQ Gas Ratio Method

The Baker Hughes INTEQ gas ratio method is a combination of three ratios, which when plotted together suggests a fluid character. The ratios are designed to be plotted on a depth log (unlike the Rectangular and Triangular plots) and still provide interpretative results. They were designed for ditch gas values rather than steam-still or DST values.

The following ratios are used:

**Hydrocarbon Wetness Ratio (Wh)**

$$\frac{C_2 + C_3 + C_4 + C_5}{C_1 + C_2 + C_3 + C_4 + C_5} \text{ x } 100$$

When this parameter is plotted (Figure 3-5) it will increase with an increase in both gas and oil densities. Guidelines for the interpretation are:

| Wh% | Fluid Potential |
|---|---|
| < 0.5 | Non-productive dry gas |
| 0.5 to 17.5 | Potential gas - Increasing density with increasing Wh% |
| 17.5 to 40 | Potential oil - Increasing density with increasing Wh% |
| > 40 | Residual oil |

**Hydrocarbon Balance Ratio (Bh)**

$$\frac{C_1 + C_2}{C_3 + C_4 + C_5}$$

This parameter is related to the density of the reservoir fluid, decreasing with an increase in fluid density.

**Hydrocarbon Character Ratio (Ch)**

$$\frac{C_4 + C_5}{C_3}$$

This parameter is used when excessive methane is present, which tends to retard the Wh and Bh ratios, affecting their curve movement. The Ch can also be used as a check and will aid in determining whether gas, oil or condensate potential is indicated.

The interpretation of these ratios is a study of the relationships of the Wh, Ch and Ch curves and values.

The first step is the study of the Wh, using the previously mentioned set-points to determine the fluid character. Secondly, comparing the relationship of the Bh to the Wh will assist in confirming the fluid character in the following manner:

1. If the Bh is > 100, the zone is excessively dry gas
2. If the Wh is in the gas phase and the Bh > Wh, the closer the values/curves, the denser the gas
3. If the Wh is in the gas phase and the Bh < Wh, gas/oil or gas/condensate is indicated
4. If the Wh is in the oil phase and the Bh < Wh, the greater the difference/separation, the denser the oil.
5. If the Wh is in the residual oil phase and Bh < Wh, residual oil is indicated.

After comparing the Wh and Bh values/curves, the Ch is checked if situation 2 or 3 occur.

1. If the Ch < 0.5, gas potential is indicated and the Wh vs. Bh interpretation is correct
2. If the Ch > 0.5, gas/light oil or condensate is indicated

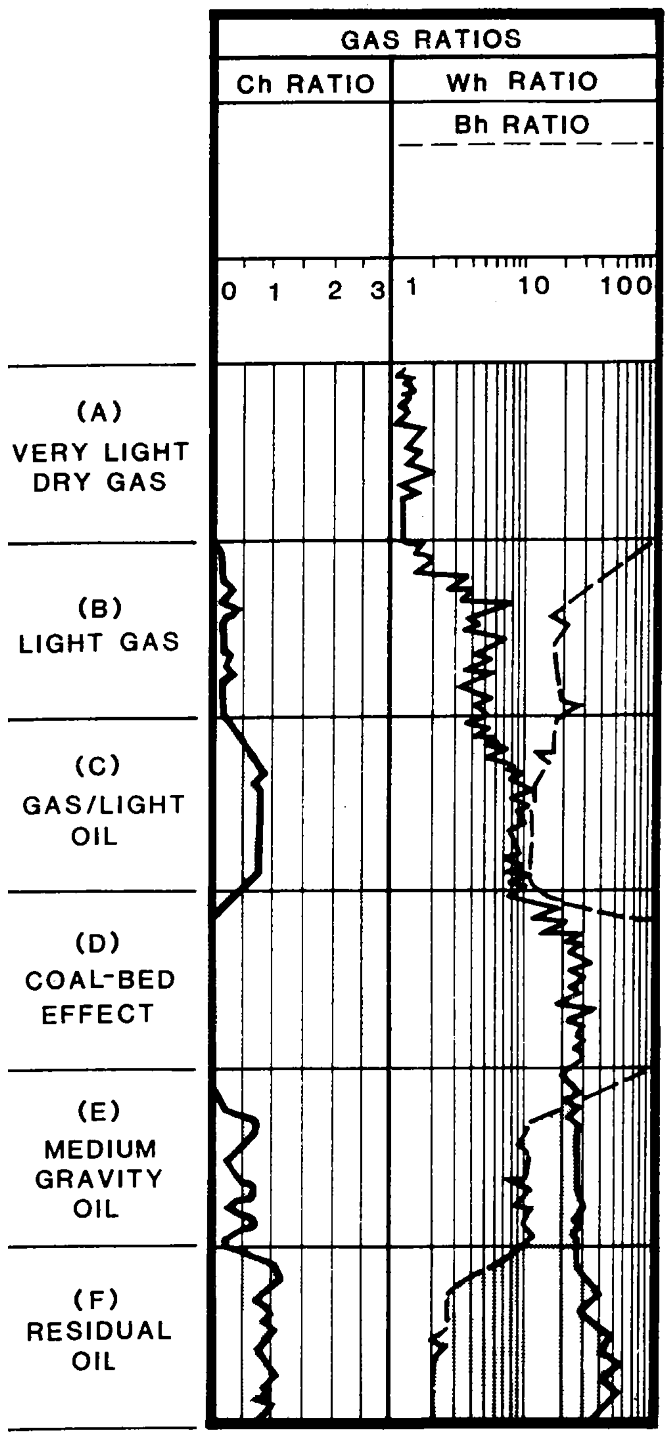



Figure 3-5: Baker Hughes INTEQ Gas Ratio Method

It must be stated that all conclusions drawn from these ratio analyses do not consider porosity, permeability or the fallibility of the gas extraction system. As such, they should not be considered as stand-alone methods of interpretation, but rather as enhancements to conclusions.

## Summary

When evaluating hydrocarbon shows, the Wellsite Geologist must use all available techniques, all possible tests, and review all available parameters to ensure that the show is truly from the formation and not caused by some artificial or misleading information.

The Wellsite Geologist will fill out the client's show report while the mud loggers will provide one of their own for attachment to the mud log. The two reports should be reviewed for consistency and any disagreements resolved before submittal to the Operations Geologist.

Hydrocarbon show analysis, at present, is qualitative, and terms such as poor, fair, and good are subject to individual interpretation. When more than one report is submitted for review, it is imperative that the show rating be identical or as close as possible to avoid confusion.

Again, communication between the Wellsite Geologist and the mud loggers will ensure that test procedures, show analysis and interpretation techniques are followed in the same manner and that results are comparable.

•Notes•

# Drilling Engineering

In addition to having a good geological interpretation and show evaluation skills, the Wellsite Geologist must understand how the drilling parameters affect their interpretations of those subsurface formations.

Detailed information concerning the principles behind drilling engineering practices can be found in INTEQ's "*Drilling Engineering Workbook*".

## Observation & Interpretation

The drilling parameters that the Wellsite Geologist is primarily concerned with are those affecting the drillstring and mud system. Although they provide useful information for the drilling engineers, they also affect the interpretation of all the geological data collected at the wellsite.

## Drilling Parameters

One of the most useful "real time" geological tools is the rate of penetration. This measure of drillability is dependent upon formation porosity and rock matrix strength. This ROP, when plotted, commonly shows a strong correlation to the Sonic, the SP, and Gamma Ray logs. The ROP is primarily affected by:

- Bit type (Roller Cone or Fixed Cutter)
- Weight-on-Bit
- Rotary Speed
- Pump Pressure
- Nozzle Size
- Mud Density

The Wellsite Geologist should be aware that different bit types will drill similar formations differently. When comparing well data, it is useful to compare the IADC classifications of the bits used. In general, longer toothed bits are used in the softer formations. For example, the selection of a short-toothed bit to drill a soft clay formation will lead to bit balling and slow drill rates.

If the Wellsite Geologist is called upon by the drilling supervisor to assist in bit selection (particularly PDC bits), since they are usually rated for formation type based on interval transit time, the geologist should relay the standard rock matrix travel times to the drilling supervisor.

Drilling parameters, such as WOB and RPM also affect the ROP, and the Wellsite Geologist should always check to ensure that these parameters have not changed significantly without their knowledge. In the event of a dramatic change in ROP, ensure that the drilling parameters have remained constant, indicating that the cause of the ROP change was due to the formation. When in doubt, treat the change in drill rate as a drill break.

Drilling fluid hydraulics also affect the ROP. Changes in drilling fluid rheology and pump output can enhance drilling efficiency through improved hydraulics. Since pump pressure is a function of pump output, fluid rheology and bit nozzle size, the Wellsite Geologist should be aware of any changes in the mud properties or nozzle sizes.

## Rotary Speed

Rotary speed is defined as the rate at which the bit is rotated during drilling operations, and is measured in revolutions-per-minute (rpm). The amount of rotation is governed by three factors:

1. Maximum efficient rate of penetration
2. Formation compressive strength
3. Bit type

The general relationship between rotary speed and drill rate is that the faster the rpm, the higher the drill rate. However, there is an inverse relationship between rotary speed and formation compressive strength, with high rotary speeds in soft formations and low rotary speeds in hard formations

## Weight-On-Bit

The amount of weight that may be added on any bit is provided by and limited by bit size and the drillstring (especially the drill collars). The Drilling Engineering principles state that “while drilling, the drillpipe above the collars must be held in tension”. If the drillpipe is put into compression, fatigue failure may result with washouts and/or twist-offs occurring.

To determine the weight that can be placed on the bit, four factors are taken into consideration:

1. The weight that can be carried by the collars. This is governed by the length of the collar section and the weight of the collars (lbs/ft). Normally, about 80-90 percent of the buoyed weight of the collars is used as the “maximum WOB”.

2. The weight necessary to keep the hole within the degree of deviation (vertical, directional, horizontal) required for the well.

   Governing factors for deviation control are bit type, the formations, rotary speed, the number and location of stabilizers, and the outside diameter of the Bottom-Hole-Assembly.

3. The weight carrying capacity of the drill bit. This will vary with the size and type of bit. Fixed cutter bits tend to handle more weight-per-inch than do roller cone bits. The same is true for rotary speed. The working ranges for the various bit types are shown in Figures 4-1 and 4-2.

4. The weight at which the borehole is drilled most rapidly. This is most often determined through “drill-off” tests.

Once the weight carrying capacity of the drill bit has been determined, and the other drilling parameters taken into account (safety factors, hole deviation, etc.), the maximum weight-on-bit for optimum rate of penetration can be determined. For a specified WOB, a certain number of drill collars will be required. This is determined using:

$$\text{no. of D.C. singles required} = \frac{\text{Maximum W.O.B}}{\text{D.C.}_{max} \times \text{B.F.} \times L \times WT}$$

where:

| | |
|---|---|
| WOB = | weight-on-bit (lbs) |
| D.C.$_{max}$ = | maximum drill collar weight used (%) |
| B.F. = | buoyancy factor of the mud |
| L = | average length of one drill collar (ft) |
| WT = | average drill collar weight (lbs/ft) |

Changes in the WOB, when not intentionally changed by the driller, often indicate changes in the formations. The WOB will normally vary proportionally to the hardness or compressive strength of the formation. Soft or unconsolidated formations require little WOB, while hard formations require the maximum amount of WOB.

| Series | Type | WOB (lbs/in) | Rotary Speed |
|---|---|---|---|
| 1 | 1 - 2<br>3 - 4 | 2000 - 7000<br>3000 - 7000 | 250 - 60<br>175 - 60 |
| 2 | 1 - 2<br>2 - 4 | 3000 - 8000<br>3000 - 8000 | 90 - 50<br>80 - 45 |
| 3 | 1 - 2<br>3 - 4 | 4000 - 9000<br>5000 - 10000 | 70 - 45<br>70 - 35 |
| 4 | 1 - 2<br>3 - 4 | 1000 - 3500<br>1500 - 3500 | 100 - 60<br>120 - 60 |
| 5 | 1 - 2<br>3 - 4 | 1500 - 4800<br>2400 - 5000 | 90 - 40<br>70 - 40 |
| 6 | 1 - 2<br>3 - 4 | 2600 - 5600<br>3000 - 6300 | 65 - 35<br>60 - 35 |
| 7 | 1 - 2<br>3 - 4 | 2700 - 6500<br>2500 - 6500 | 60 - 35<br>65 - 35 |
| 8 | 1 - 4 | 2500 - 7000 | 50 - 35 |

**Figure 4-1: Working Ranges for Roller Cone Bits**

| Formation Hardness | Bit Type | WOB (lbs/in) | Rotary Speed |
|---|---|---|---|
| Soft | PDC | 500 - 2500 | 80 - 1400 |
| Medium Soft | PDC | 1000 - 3000 | 80 - 600 |
| Medium | PDC<br>Diamond<br>TSP | 1500 - 3500<br>2000 - 4500<br>2000 - 4500 | 80 - 1400<br>80 - 350<br>80 - 350 |
| Medium Hard | Diamond<br>TSP | 2000 - 4500<br>2000 - 4500 | 60 - 350<br>60 - 350 |
| Hard | Diamond | 2000 - 4000 | 60 - 350 |

**Figure 4-2: Working Ranges for Fixed Cutter Bits**

## Hookload

Total hookload represents the weight suspended in the derrick. This weight includes; the drillstring, kelly (if used), elevators, traveling block and drill line. Since all components, except the drillstring maintain a constant weight, a value can be obtained for the drillstring weight, whenever necessary. This value is of prime importance during trips and connections.

When tripping out of the hole, the total hookload should decrease by the buoyed weight of the stand removed from the drillstring. During a connection or when tripping in, the total hookload should increase by the buoyed weight of the single/stand added to the drillstring.

Fluctuations in this drillstring weight will be due to the interaction between the drillstring and the borehole.

This interaction may indicate:

- Swelling or sloughing clays/shales, indicating high water loss or an overbalanced situation. This will cause increased overpull (drag) and can impede pipe movement.
- Excessive filter cake build-up on permeable formations
- The drillstring becoming differentially stuck on a permeable formation.
- Junk in the hole, preventing the bit from reaching bottom
- Dog-legs causing the bit to hang up or drag in the borehole
- A hole washout preventing the drillstring from finding the true borehole or the drillstring is hanging up on a ledge.
- A smaller borehole causing the drill collars and stabilizers to come into contact with the borehole

Knowledge of borehole stability, formation pressures and survey data will assist in determining the correct explanation. An up-to-date pipe tally, listing the position of the collars, stabilizers and other specialized subs in the drillstring, and their location in the borehole will give a better idea as to the whereabouts of any problems.

As mentioned earlier, each time a connection is made, the hookload will increase by the buoyed weight (the effect of mud density) of the single. The equation is:

$$B.W. = (Wt \times L) \times [1 - (0.015 \times MW)]$$

where:

Wt = weight of a single/stand (lbs/ft)
L = length of a single/stand (ft)
MW = mud density (lbs/gal)

For example:

A 31.50 ft (19.5 lbs/ft) single added to a 13.2 lbs/gal mud.
B.W. = (19.5 x 31.50) x [1 - (0.015 x 13.2)]
B.W. = 614.25 x 0.802
B.W. = 492.63 lbs

### Standpipe Pressure

This is the drilling fluid circulating pressure which is necessary to maintain efficient drill rates. It is measured at the standpipe using a pressure gauge.

Inconsistent standpipe pressures, when using fixed cutter bits, may indicate:

| PDC bits | Diamond or TSP bits |
|---|---|
| Bit Balling | Broken or Nodular Formations |
| Annulus Packing Off | BHA Hanging Up |
| Flow Rate Variations | Poor Stabilization |

In addition, changes in the established pump pressure will generally indicate problems either in the borehole or in the drillstring.

| Increases in standpipe pressure | Decreases in standpipe pressure |
|---|---|
| 1. Flow rate increases | 1. A washout in the drillstring |
| 2. A restriction in the annulus | 2. Taking a kick |
| 3. Bit balling | 3. Lost circulation |
| 4. Plugging up of a jet | 4. A lost nozzle |

### Rotary Torque

Torque is the force created by the drillstring due to its rotation in the borehole. A portion of the torque is generated by the bit, the remainder will depend on the bottomhole assembly and drillpipe. Therefore, torque is a function of the rotary speed and hole conditions. Torque is normally measured in foot-pounds. However, when a diesel electric or SCR rigs are used, the amount of electric power required by the motors to rotate the drillstring is electric torque, measured in amperes.

Relatively constant torque values indicates normal drilling conditions. Two levels reflect formation hardness:

- Low Torque Values - Soft or plastic, homogeneous formations
- Medium Torque Values - Soft to medium hard homogeneous formations

Erratic torque readings can indicate one or more of the following:

- Reaming of the stabilizers
- The bit is undergauge
- Interbedded formations
- Bit balling

- Rotary Speed changes
- Keyseats or doglegs
- Excessive weight-on-bit
- Junk in the borehole

Sporadic or constant increases in torque may indicate:

- A formation change
- Unoptimized bit weight
- Unoptimized rotary speed
- An undergauge bit
- A drillstring washout
- Increasing borehole inclination
- Increasing filter cake thickness

Sporadic or constant decreases in torque may indicate:

- A formation change
- Unoptimized bit weight
- Unoptimized rotary speed
- Decreasing borehole inclination
- Bit Balling
- Decreasing filter cake thickness

## Drilling Exponents

A drilling exponent is a method of normalizing the ROP for changes in WOB, RPM, and hole size. A corrected version has functions for ECD and normal formation pressure to take into account differential pressures while drilling. Some mud-logging companies have “second and third generation” exponents to account for tooth efficiency and formation abrasiveness. These drilling exponents are dimensionless.

Changes in exponent values are generally attributed to formation changes, either lithology or porosity. It should be noted that variations in exponent trend may occur through hydraulic action, such as in soft clays where jetting is the main influence on drilling rate. Exponents are generally used as a formation pressure indicator.

The most common drilling exponent is the DXC, and is calculated using;

In standard oilfield units

$$Dxc = \frac{\log \frac{R}{60N}}{\log \frac{12W}{10^3 B}} \times \frac{N.P.P.}{ECD}$$

where:

| | |
|---|---|
| R | = Rate of penetration (ft/hr) |
| N | = Rotary speed (rpm) |
| B | = Hole diameter (inches) |
| N.P.P. | = normal (lb/gal) |
| ECD | = Equivalent circulating density (lb/gal) |
| W | = weight on bit (klbs) |

The metric equivalent is:

$$Dxc = \frac{\log \frac{R}{18.29N}}{\log \frac{W}{14.88B}} \times \frac{N.P.P}{ECD}$$

where:

| | |
|---|---|
| R | = Rate of penetration (m/hr) |
| N | = Rotary speed (rpm) |
| B | = Hole diameter (cm) |
| N.P.P. | = normal (g/cc) |
| ECD | = Equivalent circulating density (g/cc) |
| W | = weight on bit (tonnes) |

The normal formation pressure is referenced from the flowline, and is expressed as a gradient. It will always be less than the true formation pressure gradient which is referenced from either the water table (onshore) or sea-level (offshore).

## Drilling Fluid Parameters

The mud system and the various components of the mud chemistry affect the interaction between the drill bit and formation. The Wellsite Geologist should have an understanding of these interactions and be aware of the properties that influence them.

The mud system serves many purposes and though functions are more relevant to the drilling operation, those that are of interest to the geologist include:

- Controlling subsurface pressures (mud density)
- Cuttings removal (viscosity)
- Suspending cuttings when not circulating (gel strength)
- Providing an impermeable wall cake (filtrate)
- Releasing cuttings at surface (viscosity & gel strength)

## Mud Density

One of the main functions of mud density is to provide a balance between the fluid column and formation pressures. The pressure at the bottom of the borehole is a function of the vertical height of the fluid column and the density of the fluid. This pressure is defined as the “mud hydrostatic pressure” and is referenced to the flowline.

$$P = 0.0519 \times W \times TVD$$

where:

| | |
|---|---|
| P | = hydrostatic pressure (psi) |
| W | = mud density (ppg) |
| TVD | = vertical depth (ft) |

or

$$P = 0.0098 \times W \times TVD$$

where:

| | |
|---|---|
| P | = hydrostatic (kPa) |
| W | = mud density (kg/m$^3$) |
| TVD | = vertical depth (m) |

When circulating, the pressure exerted by the mud column increases due to frictional pressures losses within the borehole annulus. Those pressure loses can be calculated using:

Annular Pressure Loss in laminar flow (Bingham):

$$P = \frac{L \times YP}{200(Dh - Dp)} + \frac{L \times PV \times V}{60000(Dh - Dp)^2}$$

where:

| | |
|---|---|
| L | = length of annular section (ft) |
| V | = annular flowrate (ft/min) |
| Dh | = Hole diameter (inches) |
| Dp | = Drill pipe diameter (inches) |
| YP | = Yield point (lbs/100ft$^2$) |
| PV | = Plastic velocity (cps) |

This annular pressure loss is calculated for each individual annular section. The equivalent circulating density is then calculated by adding those pressure losses to the mud density.

$$ECD = MW + \frac{\sum Pla}{0.0519 \times TVD}$$

Should the mud hydrostatic pressure fall below the formation pressure, (i.e. become underbalanced), the possibility of fluid incursions into the well-bore is greatly increased. The amount of incursion will be dependent upon the formations porosity and permeability. When formation pressure is greater than the mud hydrostatic pressure the following may be seen:

- Large quantities of cavings (due to wellbore instability)
- Connection gases
- Trip gases
- Increased background gas
- Fluid incursions to the mud system

If the hydrostatic pressure is greater than the formation pressure, (i.e. overbalanced), then flushing of the formations will take place.The degree of overbalance by the mud column will affect both the ROP (impeding cuttings removal) and the gases recorded at surface (due to flushing).As a general rule, the drill rate will decrease as the mud weight is increased.

### Viscosity

As has been mentioned earlier, viscosity has an effect on cuttings recovery. Intuition suggests that a more viscous fluid would have an increased carrying capacity and hence retrieve cuttings more effectively. Viscosity also affects the flow regime of the fluid, which has an even greater effect upon the carrying capacity of the mud system. Generally, the higher the viscosity of the fluid, the more likely the fluid is to be in laminar flow. Though annular flow is not as effective as turbulent flow for removing cuttings, using turbulent flow throughout the annulus would result in a washed out hole.

Plastic viscosity (PV) is a measure of resistance to flow caused by the mechanical friction between the drilled solids in the mud, the make-up solids and liquids, and the shearing properties of the mud itself. This is one of the primary reasons for controlling mud solids.

In the mud system there are solids that are an integral part of the mud (bentonite, starch, CMC, etc.) and solids that are undesirable (sand, limestone, dolomite, etc.). As the mud density is increased, by the addition of barite or hematite (more solids), the plastic viscosity will automatically increase. The PV is also a function of the viscosity of the fluid phase of the mud. So as temperature rises, the viscosity of water decreases, hence PV will decrease also.

### Yield Point

The yield point (YP) is a measure of the electro-chemical attractive forces within the mud under flowing conditions. These forces are a result of positive and negative charges located near or on the particle surfaces within the mud. The yield point then is a function of the surface properties of the mud solids, the volume concentration of the solids and the concentration and type of ions within the fluid phase.

It is also measure of flocculation, which can be caused by the introduction of soluble contaminants such as salt, cement, anhydrite, or gypsum. The breaking of clay particles by the grinding action of the bit and pipe also causes flocculation. Introduction of inert solids causes the particles to be closer together and hence have an increased attraction and the drilling of hydratable clays introduces active solids which may flocculate.

### Gel Strength

Gel strength is a measurement that denotes the thixotropic properties of the mud. It is a measurement of the attractive forces of the mud while at rest or under static conditions. As this and yield point are both measures of flocculation they will tend to increase and decrease together.

### Filtrate/Water Loss

Loss of fluid (usually water and soluble chemicals) from the mud system into the formation occurs when formation permeability is such that it allows fluid to pass through the pore spaces. As fluid is lost a build up of mud solids occurs on the face of the wellbore. This is filter cake. Two types of filtration occur, dynamic, while circulating and static, while the mud is at rest. Dynamic filtration reaches a constant rate when the rate of erosion of the filter cake due to circulating matches the rate of deposition of the filter cake. Static filtration causes the cake to grow thicker with time, which results in a decrease in fluid loss with time.

Mud measurements are confined to the static filtration. Excessive filtration and thick filter cake build up are likely to cause the following problems:

- Tight hole, causing excessive drag.
- Increased pressure surges due to reduced hole diameter.
- Differential sticking due to an increased area of pipe contact in filter cake.
- Excessive formation damage and evaluation problems.

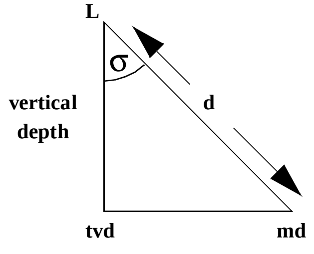
Most of these problems are caused by the filter cake and not the amount of filtration. The aim is to deposit as thin and impermeable a filter cake as possible. A low water loss may not do this, since the filter cake is also dependent upon the solids size and their distribution.

### Other Mud System Properties

There are other mud properties that should be observed by the Wellsite Geologist. Changes in chlorides content may indicate the drilling of a permeable formation with a different fluid content. Small incursions may not be spotted by the drill crew if excessive mud treatment is being carried out, but changes in the chlorides content may indicate their presence.

## Estimation of True Vertical Depth (TVD)

A rough estimation of TVD, based on MWD or other directional survey data, can be made using the following formula:




$$TVD = (\cos\sigma \times d) + \text{last } TVD(L)$$

where:

| | |
|---|---|
| $\sigma$ | = cosine of survey angle (degrees) |
| d | = course length |

This formula assumes that the well path between individual survey points is a straight line, whereas in reality it will be curved. Generally, with frequent surveys, the results should be within a couple of feet when compared to the more complicated formulas (i.e. Minimum Curvature Method).

## Information Acquired During Drilling

Information acquired by the Wellsite Geologist during the drilling operations is vital to the success of the well. As the well gets deeper and more data is collected, the geologist's recommendations can have a significant impact on the well program.

### Interpretation of the Drill Rate

Measuring the drill rate can vary from recording the time (in minutes) it takes to drill a five-foot interval on the kelly, to sophisticated computer printouts in feet-per-hour (or meters-per-hour). Drill rate is one of the few rig parameters recorded “real-time” and can give an indication of what is happening at the bottom of the borehole. This parameter is especially useful when looking for lithology changes, for picking formation tops, and when looking for potential zones of interest prior to coring.

An experienced driller can interpret the nature of a formation just by “feeling” how that formation drills. The classic drilling-break (increase in rate of penetration and decrease in torque) is often associated with a friable formation (porous and permeable). The exact opposite, a sudden reduction in drill rate and an increase in torque, often indicates a hard formation. If the pump pressure increases at the same time, it may suggest bit balling, or a worn bit.

Fracture porosity can often be inferred when drilling becomes rough, with fluctuating torque and kelly bouncing (kelly jitter).

As mentioned at the beginning of this chapter, there are many variables which affect the rate of penetration, so conclusions concerning the significance of drill rate changes must be evaluated against all drilling parameters. If all are constant, then the changes in drill rate reflect changes in lithology. When comparing data from several wells, it is “changes” in the rate of penetration, rather than the actual value that is significant when correlating.

A different dimension is introduced when directional or horizontal drilling. The angle at which the bit penetrates the formation will strongly influence the drill rate. For example, when “vertical wells” in the same field are correlated, some formations will drill faster than others, whereas in “directional wells”, the same formation will drill differently, even if the drilling parameters are kept constant. This anomalous effect is not fully understood, but the difference in “surface vs. downhole” drilling parameters have some effect, as does the angle of the borehole in relation to the formation dip. In these situations considerable skill is required for subsurface interpretation while drilling is in progress, especially if sample quality is poor.

When drilling with an “automatic driller”, correlations between drill rates can be very difficult, especially if the offset wells did not use the automatic drilling system.

All pipe tallys and drillers depths should be checked regularly and all discrepancies accounted for, with the request for strapping out if necessary.

The Wellsite Geologists should beware of poor drilling practices, such as drilling as fast as possible to complete the hole as soon as possible.The concept of “speed drilling”, especially with the new technology in the oilfields (i.e. exotic muds, mud motors, long-life fixed cutter bits, etc.), must be considered when correlating drill rates between wells. Wells in the past drilled a lot slower than today. Thus the concept of drill rate changes rather than actual values takes on added significance.

Drilling characteristics of certain horizons are often more revealing and informative than geological markers in correlation work. The Wellsite Geologist and driller should communicate on a regular basis and always be alert to variations in the drilling parameters. The well should “talk” to both of them.

## Geological Considerations

As formation tops are picked, the geologist should determine if:

- The pre-well structural interpretations are correct
- The pre-well stratigraphic interpretations are correct
- If facies changes have occurred in the stratigraphic section

As cuttings samples are evaluated, the geologist should determine if:

- The suspected reservoirs are present
- The reservoirs are as thick as determined in pre-well planning
- The reservoirs have both a source rock and a trapping mechanism

- Do the samples indicate potential drilling problems

As hydrocarbon shows are interpreted, the geologist should determine if:

- The quality of the reservoirs fit the pre-well expectations
- The hydrocarbons support pre-well indications

As the geologic information is evaluated and drilling progresses, the Wellsite Geologist should use the information to assist in the modification of the drilling program, in particular:

- Are the types of drill bits sufficient?
- Does the mud system require modifications?
- Which formations require testing?
- Which formations require coring?
- Does the wireline logging program require modification?
- Does the casing program require modification?

And the most important question: **Should drilling continue?**

•Notes•

# Lithlog/Striplog Preparation

## Preparation and Drafting of the Lithlog/Striplog

The Wellsite Geologist's lithlog is a permanent record of their observations at the wellsite. While much of the information on it will be similar to that on the mud log, due to inconsistencies and lack of information on many mud logs, oil companies have their own standard lithlog forms that are used on their wells. In addition, the lithlog provides a more detailed lithologic record than many mud logs.

As with other wellsite reports, when preparing lithlogs, be consistent with the client’s offset lithlogs.

The log is generally hand-drafted, but software packages are allowing the geologist to input data and have the log computer-drafted. It is common for the lithlog to be produced at a similar scale to the other wellsite logs (mud logs, wireline logs and MWD logs). This allows for correlation, easy comparison while drilling is taking place, and provides space for detailed cuttings descriptions. Many such logs contain the following real-time and lag-time information.

### Rate of Penetration

The method of drill rate calculation (ft/hr, m/hr, min/ft, min/m) should be displayed in the column, along with the variable scale. The scale should be constructed so that the drill rates increase from right to left (this allows easy correlation with the SP or Gamma Ray log). Either linear or logarithmic scales can be used. The scale chosen should be one that makes the best use of the whole column without recourse to scale changes or back-up scales. As with wireline and MWD logs, the scale should have the “average” drill rate in the center of the column, and the slowest drill rate should fall on the second scale division from the baseline. If a back-up (or wrap-around) scale is necessary, the normal back-up is “x10”. If scale changes are necessary, then a prominent note should be made illustrating the previous scale and the new one.

The drill rate curve can be drafted either in a histogram fashion or as a vector plot. The most common calculation interval is every 5 feet. Generally, it is an average of the ROP over that five foot interval. Coring intervals are often plotted at smaller intervals than the drill rate.

A notation or symbol indicating the casing shoe depth should be placed inside the right margin of the penetration rate column. Visual porosity (if it doesn't have its own column) can be displayed in this column, with porosity increasing from right to left.

Intervals “logged after trip” (LAT) and intervals circulated out (CR) can be noted in the drill rate column. Flow checks are noted using “FLC” followed by (+) denoting a positive flow check or (-) for a negative flow check.

### Depth

The depths, at the appropriate scale (generally 1-inch = 100 ft), should be aligned to exactly bisect the depth line on the log. Try to avoid depth markings which overlap at the top and bottom of the sheet, but if this is unavoidable, be sure that they will align properly when the log is spliced.

### Interpreted Lithology

This column is interpreted lithology as opposed to cuttings lithology. While cuttings lithology is intended to portray the actual lithology and percentages seen in the cuttings sample, interpreted lithology permits the Wellsite Geologist to use other data such as drill rate, gas, etc. as well as cuttings lithology, to better interpret the actual rock being cut.

The symbols used when drafting lithology should conform to industry recognized standards (AAPG/SPWLA), unless the oil company has reasons to deviate from them. Do not change any symbols without prior consultation with the client’s Operations Geologist or their supervisor.

### Lithology Description

Sample descriptions should be placed often enough to accurately describe the lithology column. All lithology descriptions must follow the format described in Chapter 2. All abbreviations must conform to the SPWLA/ AAPG standardized abbreviation format. Any word not listed (see Appendix A) must be spelled out in full.

When describing a lithology, put yourself in the place of the person who will read it. Make the description readable and useful. If “as above” (a/a) is needed, use it. Changes in a lithology are generally more important than a repeat description.

### Show Description

The show description should follow the format described in Chapter 3. Include the show number.

## Gas with Chromatographic Breakdown

Some lithlogs do not require gas curves to be plotted by the Wellsite Geologist. More often, gas curves are incorporated by the logging company onto the mud log. In their place, the Wellsite Geologist can plot gas ratios or a cumulative gas (a sum of all the chromatograph gases). Gas values can also be entered into a spreadsheet in an ASCII format for analysis through a number of computer routines.

When drafted, the gas curves should be carefully evaluated before they are drawn onto the log. Remember, chart recorders are time constant, while the log is drawn against depth. When transposing from chart to log, try to incorporate on the log as much of the peak and trough detail as possible. The Continuous Total Gas curve is drawn as an unbroken straight line in proportion with the curve seen on the chart recorder.

Gas curves should be drafted in SPWLA recognized units (percent EMA or ppm). Generally, the Wellsite Geologist will follow the mud loggers gas units, but this is not always the case.

When produced gases are recorded, they should be aligned under one another, except where this would obscure the total gas curve. The following abbreviations are used:

| | | | |
|---|---|---|---|
| TG | Trip Gas | STG | Short Trip Gas |
| CG | Connection Gas | SVG | Survey Gas |

When chromatograph gases are plotted, the curves should be labeled by a number representing the gas (e.g. 1 for C1, 2 for C2, etc.). The re-appearance of a gas onto the plot should also be labeled in this way, otherwise it is not necessary to re-label the curves again on the sheet unless confusion would result from not doing so. Peaks in the chromatograph curves should correspond to peaks in the Continuous Total Gas curve.

## Engineering Data

Drilling information which affects the drill rate, lithology, hydrocarbon evaluation, etc. should be included on the log. The most important are weight-on-bit (WOB), rotary speed (RPM) and pump pressure (SPP). The pump strokes (SPM) can be added if desired. Radical changes in the drilling parameters should be noted at the depths where they occur. For example:

| | |
|---|---|
| WOB 35 Klbs | Incr WOB |
| RPM 100 | or |
| SPP 2500 psi | Decr RPM |
| SPM 90 | |

### Mud Data

Mud checks and mud properties information can be included on the lithlog, especially when changes affect the drilling operations and interpretation parameters. Mud density and viscosity should be noted more frequently, particularly when drill rates are high. Other parameters worth noting are; filtrate loss, pH, chlorides, PV, YP, and filter cake thickness. When using an oil-based drilling fluid, also include the oil/water ratio and the electrical stability (ES) in the mud data.

### Remarks

Additional information such as formation tops, sample sieve sizes, shaker screen sizes, bit data, casing shoes, wireline and MWD log runs, formation tests, conventional and sidewall cores, and drilling problems information can be added to make the lithlog a complete source of information.

As this is the most timely, graphic way of depicting the geologists interpretations it must be kept up to date. This will aid in correlation and allow rapid data transmission to local offices by facsimile.

## Interpretation of the Lithlog

The interpretation of the lithlog is only as good as the information plotted on it, and the knowledge of the person reviewing the log. As with any type of interpretation, it is imperative that all parameters be looked at in total.

### Lithological Interpretation Problems

During the drilling process, large scale sedimentary features are usually broken up by the drill bit. However, some can be recognized and reconstructed in the cuttings samples. Any extrapolation and interpretation of a drilled section using cuttings can be confirmed with cores, wireline or MWD logs.

Poorly consolidated sediments, especially very fine sands, which may fall through the shaker screens or through the sieves used for washing, can be detected by looking elsewhere. It is always advisable to check the de-sanders and de-silters when a cuttings sample is collected. Matrix material (clay and silt) can also be washed out of a sample.

Limestones can be drilled into a paste, and can wash out of a sample, or occur as a structureless mass in a washed sample. For example, when drilling a limestone with chert streaks, if the limestone becomes a paste, the section can be interpreted as all chert, as opposed to minor chert streaks in a limestone.

Conglomerates can be identified from cuttings. Even though the pebbles and coarse particles will be broken up, rounded edges will still be identifiable. Those edges will also have a weathered appearance. The identification of a conglomerate might indicate an unconformity. Though this evidence is inconclusive, it is important to extrapolate using additional evidence. For example, if there are concentrations of phosphate, pyrite or glauconite also in the cuttings, this may confirm an unconformity. Basal conglomerates are generally more heterogeneous and weathered (weathered chert and blackened limestone pebbles) than the “bone and tooth” type conglomerates which accumulate as lag zones overlying the unconformity.

Salts and evaporites, if drilled with an non-inhibited mud system, will go into solution and be absent at the surface. Many times all that survives the travel to the surface is the space where those minerals occurred (i.e. salt casts in dolomite and anhydrite). Probably the most common indication of drilling through a salt or evaporite section will be the lack of cuttings, when no loss of circulation is occurring. Anhydrite cutting can become soft and plastic, resulting in rounded, spherical cuttings.

The type of bit used while drilling will have a profound effect on the shape and size of the drill cuttings. Powdering and pulverization of the cuttings by the grinding action of the bit can cause the cuttings to form “rock flour” or paste. This paste can then be washed out during the cleaning process. Fixed cutter bits (PDC, diamond and TSP) will shear the formation as they drill. In hard formations this action will “burn” cuttings, and in soft to plastic formations this action will result in large, crenulated cuttings being formed.

A very good description of bit-generated cuttings can be found in the AAPG Bulletin, V.70, No. 9, “Bit-Generated Rock textures and Their Effect on Evaluation of Lithology, Porosity, and Shows in Drill-Cuttings Samples”, by William Graves.

•Notes•

Chapter **6**

# Mud Logging Operations

## Introduction

Mud logging is a contract service, which the oil company employs to monitor wellsite activities, and to analyze the drill cuttings for lithology identification and hydrocarbon shows. The resulting plots of those wellsite activities and cuttings analysis versus depth is termed a mud log.

The quality control of those operations is the responsibility of the Wellsite Geologist. The Wellsite Geologist must be certain that the equipment necessary to monitor wellsite activities is working properly, and is used to its best advantage. To be effective there must be close communication between the geologist, the mud loggers and the rig personnel.

In addition, much of the information required by the Wellsite Geologist is obtained from the mud logging unit. It is therefore essential that the data quality be as valid as possible. Depending on the situation, the mud logging unit may be a simple standard unit (monitoring gas, ROP and pump strokes only), or a more sophisticated computerized unit monitoring a large range of drilling and tripping parameters around the rig.

One of the most important aspects of initial inspection is the quality control of logging unit installation and checking that all company and government requirements regarding safety have been met. This will usually fall under the drilling departments jurisdiction, but the geologist will most likely be the person entrusted with ensuring that the logging unit and crew operate effectively. In general, quality control of the mud logging unit will include:

1. Ensuring that the logging unit and equipment are installed properly and maintained. Regular equipment calibrations should be performed and witnessed.
2. Gas detectors (Total Gas, Chromatograph, $H_2S$, $CO_2$) should be checked regularly. Alarm set-points should be noted.
3. Gas detectors are to be correctly zeroed with pure air and calibrated with gases of known composition. A record should be kept of these calibrations.
4. All drilling parameter recorders must function correctly and read accurately. The most important recorded parameters are WOB, RPM, Torque, Mud Density, Mud Temperature and Return Flow Rate.

With computerized logging units, it is possible for much of the monitoring to be automatic, and sophistication can also lead to the logging crew to become lax with checking the equipment.

The mud logging crew should never display false or inaccurate data on rig monitors (i.e. Return Flow). They should let the company man and client know of any malfunctions or inoperative equipment. In some areas (e.g. Norway), drilling can be halted if critical equipment (i.e. gas detectors) are inoperative.

Carbide lag checks should be run regularly. These allow the monitoring of hole integrity, and are performance checks on the entire gas system. An example of a regular check is to have it performed at least once a day. Carbide is inserted into the gas trap for gas system checks, as well as placed in the drillstring. This allows for a comparison of the time it takes for a sample from the ditch to reach the recorders and provides an approximation of the mud system's gas retention capabilities.

During the course of the well, the logging unit crew will be producing the mud log, and the geologist should be familiar with it's layout. Though each contractor has it's own style, the information recorded on it is essentially the same. The SPWLA has put forth a “recommended format” and the contractor should try to adhere to this standard. While the Wellsite Geologist’s lithlog and the mud log will not be identical, the geologist should perform periodic checks to ensure that major discrepancies do not occur. Lithologic percentages should be similar and lithologic changes should occur at the same point on each log. Oil and gas shows should also be checked for consistency.

The Wellsite Geologist should ensure that bit data, mud data, casing point depths, wireline logs, and other “additional information” is recorded correctly. Major disagreements between the mud loggers and the geologist should be reported to town if it cannot be resolved at the wellsite. The mud loggers should keep a tabular record of all gas peaks, and produced gases such as connection and trip gases. Mud reports and deviation surveys are other types of information that should be collected by the mud loggers.

## Quality Control Procedures

As mentioned earlier, the range of services provided by the mud logging company can vary, generally the more “unknown” the area to be drilled, the more advanced the service. There are certain aspects of mud logging services that are standard to all, such as:

### Mud-Gas Separation Methods

All mud logging operations use some sort of “gas trap” to release hydrocarbons from the drilling fluid. The extracted gases are then transported, via some type of tubing, to the logging unit for analysis. Though relatively efficient (at the present time) this method does not allow for quantitative formation gas analysis.

The gas trap is located at the shale shaker, in the possum belly. A few basic QC methods include:

1. The gas trap should be cleaned of drilling fluid. A blockage of inlet air will cause variations in the gas readings.
2. The shale shaker is considered to be in a “hazardous” zone. If possible, the agitator motor should be an air driven motor.
3. The lines carrying the gas/air sample to the logging unit should be straight, with no loops, and free of condensate.
4. If the mud flow rate changes, the gas trap should be re-positioned. A change in the flow rate will cause variations in the amount of drilling fluid entering the trap, and therefore the amount of hydrocarbons released by the drilling fluid.

### Pit Level Recorders

These sensors are placed in the dirtiest place on the rigsite, in the mud pits. Because of this, the sensors are usually difficult to maintain. They are, however, critical for early prevention of well problems (i.e. kicks, lost circulation), and they must be operable at all times. For example:

1. The floats on the sensors must be clean of filter cake.
2. The sensors must be positioned so they are not obstructed by other equipment in the mud pits.
3. Pit level recorders must be accurately calibrated to monitor a ± 5 barrel gain or loss. Alarms must be set that close (when on floating rigs, a larger range may be necessary to compensate for rig movement) to prevent well problems.
4. There should be a sensor in each active pit, the trip tank, and any other pit which may receive or transfer mud.

### Drill Rate/Depth Recorder

This sensor will vary with the mud logging company. Some of the more common types are:

1. A simple wheel tied into the geolograph. This type monitors drill rate and depth with the geolograph and is affected by the same problems affecting the geolograph.
2. A water-filled bottle tied to the gooseneck. Changes in hydrostatic pressure, as the kelly or top drive moves, is

transferred to a mechanical transducer. This system is independent of the geolograph.

3. A block height sensor, which is tied into either the crown block or draw works. It monitors the position of the drill line.

Regardless of the system, the depth at any time should always be known. Though agreement between the drillers depth, mud loggers depth and wireline depth is difficult to maintain, any discrepancy should be noted and the cause of the discrepancy ascertained. When the “correct” depth is determined, all depth measurement devices (pipe tally, geolograph, mud loggers recorder) should be made to use the agreed upon depth.

## The Mud Log

As stated earlier, the SPWLA (Society of Professional Well Log Analysts) has put together an “agreed upon” policy to standardize the mud log format. Their “Recommended Procedures” can be obtained through the SPLWA, and the Wellsite Geologist should take a copy to the wellsite. To ensure compatibility between mud logging companies, those recommended procedures should be followed as closely as possible. This includes:

1. The mud log should be prepared on the same depth scales as the other well logs (MWD and wireline).
2. Rate of penetration should be plotted on a scale where the slower “shale” drill rates are two columns away from the right baseline. The drill rate should increase from right to left (to correlate with the GR or SP)
3. The description of the lithology being drilled should be complete as possible. AAPG format and abbreviations should be used. Carbonate descriptions must include the Dunham classification.
4. All bit trips should be recorded, with bit type, footage drilled, drilling hours and maximum trip gas included in the report.
5. There should be a mud check recorded daily. When there is a significant change in a mud parameters, it should be noted.
6. Note any depth corrections, and the reason the depth was corrected.
7. The new date should be placed at the appropriate depth. The date is entered at 00.01 hours.
8. Horizontal scale changes (x10 for gas and ROP, and changes in the drill rate scale) should be labelled clearly.
9. Information concerning formation testing and coring should be recorded and attached to the log as a separate report.

10. All instrument checks and calibrations should be recorded. This includes carbide lag checks and gas system performance checks.

11. Lost circulation should be recorded. Include the depth of loss, amount lost, and the type of LCM added to the mud system

12. Chemical additions to the mud system should be recorded, especially organic-based additives

13. Any extended rig downtime (abandonment for emergency, stuck pipe, waiting for equipment, etc.) should be recorded

It is realized that the mud log format is not sufficiently large enough to contain all possible information. For this reason, the mud logging company should have a “logging work sheet” which contains all the information. It will be the mud logger's responsibility to determine what and how much of the work sheet information gets transferred to the mud log. The Wellsite Geologist should review this decision-making process.

## Supervision of Mud Logging Operations

Supervision of the mud logging operations and mud loggers is the direct responsibility of the Wellsite Geologist. The main item of concern with mud logging operations is the dissemination of information. The Wellsite Geologist must ensure that the mud loggers provide all rigsite personnel with up-to-date, accurate information regarding formation characteristics, changes in the drilling or tripping parameters, hydrocarbon appearances, and safety matters. Communication of this information is vital to the success of the drilling operation.

The Wellsite Geologist should discuss with the mud logging crew the requirements regarding reporting procedures, sampling intervals, log scales, sample shipping locations, and information security. If any concerns are brought up (e.g. fast drill rates may cause the sampling interval to be adjusted, or a “sample catcher” brought to the wellsite) or additional pieces of equipment are needed they can be resolved before the concern becomes a problem.

To ensure that everyone has all the information necessary, the Wellsite Geologist should make the correlation logs and well prognosis available to the mud loggers. This will ensure that problem formations, target intervals and pressure profiles are known to the people that will probably be the first to see them.

In areas where re-supplying may take days, or be impossible, the Wellsite Geologist should check that adequate supplies and spare parts are carried by the mud logging unit. The logging unit should have a standard inventory sheet which can be cross-checked against the supplies in the unit.

During the course of the well, the Wellsite Geologist should ensure that the required reports and logs are produced and delivered on time and to the right people.

When the well is completed, the geologist must ensure that all the information collected during the course of the well, and any information given to the mud loggers is returned to the oil company. All final well reports and final logs should be completed before the logging crew and unit are released.

Also, before the Wellsite Geologist goes to sleep, they must make sure that the logging crew are fully aware of any likely events any must know the geologists requirements for those events. Encourage them to wake you if they feel it is necessary, and never give them a hard time if it turns out to be trivial. Who knows, the next time they wake you it may be an unexpected reservoir.

## EXAMPLE OF A MUD LOGGING QUALITY CONTROL CHECKLIST

### I Gas Extraction Equipment

A. Gas Trap Position

1. Positioned properly relative to flowline?
2. Mud level set to vendor's specifications?
3. Supported properly to prevent sinking?
4. Bottom lip on gas trap present?

B. Mud Agitation

Motor Type: Electric Air

Agitator Motor Speed: ____________ rpm

Blade Type: ________________ and number ________

1. Is the motor running within five percent of vendor specifications?
2. All agitator blades submerged in the mud?
3. Are there agitator malfunction alarms in the logging unit?

C. Maintenance, Operation and Spares

1. Is the gas trap washed and inspected after each trip?
2. If air agitator motor, are the air regulator and oiler in good condition?
3. Are the agitator blades in good condition?
4. Is there a spare gas trap on location?
5. Is there a spare agitator motor on location?
6. Are there spare agitator blades on location?

### II Gas Sampling Lines And Vacuum System

A. Water Vapor Condensaters

Type: _______________ Number: _______ Installed at: _____________

1. Vapor condensers checked and drained frequently?
2. Spares available on location?

B. Gas Lines

Type:____________ Diameter at Gas Trap ____________ (inches)

Diameter at Logging Unit __________ (inches)

1. Are all lines in good working condition?
2. Are there minimal splices in the lines?
3. Are the lines free of condensation?
4. Are the lines protected against adverse conditions?

C. Transfer Time

Time from gas trap to peak response: ________________ (seconds)

Response for _________ $cm^3$ carbide is a___________% C1 EMA gas peak

1. Transfer time reduced as much as possible?

D. Vacuum System

Sample Flow: _________scfh    Sample Pressure: __________ psi

1. Flow rates within five percent of vendor's specifications?
2. Are the lines from the as trap to vacuum pump free of leaks?
3. Is the vacuum pump free of leaks?
4. Is the vacuum system well maintained?
5. Is there a spare vacuum pump on location?
6. Is automatic sample dilution available?
7. Are there high/low vacuum alarms in the logging unit?

III **Total Hydrocarbon Detector**

Number present and working continuously: ____________

Type: FID Catalytic Thermal Conductivity

Time between calibrations: ________________ (hours)

A. Calibration Gas

Low Range Composition_________% C1 EMA @ __________ psi

High Range Composition_________% C1 EMA @ __________ psi

1. Laboratory analysis certificates on bottles?
2. Is there enough Low Range gas for length of well?
3. Is there enough High Range gas for length of well?
4. Are the gas bottles turned off after calibration?

B. Detector Calibration

Response with Low Range gas_______________% C1 EMA

Response with High Range gas_______________% C1 EMA

1. Detector calibrated in the last 24 hours?
2. Detector "zeroed" within two attempts?
3. Detector spanned to within ± 5% of Low Range gas?
4. Detector spanned to within ± 5% of High Range gas?
5. Calibrations marked on charts and recorded on worksheet?

C. Detector Maintenance, Operation and Spares

1. Is the high gas alarm in use?
2. Is the high gas alarm set to current gas levels?
3. Are the recorder charts annotated with depth, events and scales?
4. Are anomalous gas events indicated on charts?

FID only: Block Temperature __________ Sample Pressure __________

1. Is the Hydrogen Generator operating properly?
2. Is an alternate source of hydrogen available?
3. Is the detector set-up to vendor specifications?
4. Are there spare anodes and cathodes on location?

Catalytic only: Voltage ____________ Flow Rate ___________

Time since filament last changed _____________ (days)

1. Is the voltage set to vendor specifications?
2. Is there a flash suppressor installed?
3. Are the flash suppressors clean?
4. Are there sufficient spare filaments for the length of the well?

Thermal Conductivity only: Voltage ___________ Flow Rate ________

Time since filament last changed ______________ (days)

1. Is the voltage set to vendor's specifications?
2. Is there a flash suppressor installed?
3. Are the flash suppressors clean?
4. Are there sufficient spare filaments for the length of the well?

IV **Chromatograph**

Type: FID Catalytic Infrared Thermal Conductivity

Number of Columns: ________ Cycle Time: __________ minutes

Time between calibrations: ___________________ (hours)

1. Is a reporting integrator used?
2. Is the integrator measuring peak area?
3. Can the chromatograph routinely analyze pentanes?

A. Calibration Gases

Low Range Gas: at ____________ psi

| | | | | | |
|---|---|---|---|---|---|
| C1 | _____________ | ppm | iC4 | ____________ | ppm |
| C2 | _____________ | ppm | nC4 | ____________ | ppm |
| C3 | _____________ | ppm | iC5 | ____________ | ppm |
| | | | nC5 | ____________ | ppm |

High Range Gas: at ____________ psi

| | | | | | |
|---|---|---|---|---|---|
| C1 | ____________ | ppm | iC4 | _____________ | ppm |
| C2 | ____________ | ppm | nC4 | ____________ | ppm |
| C3 | ____________ | ppm | iC5 | ____________ | ppm |
| | | | nC5 | _____________ | ppm |

1. Are the laboratory analysis certificates on the bottles?
2. Is there enough Low Range gas for the duration of the well?
3. Is there enough High Range gas for the duration of the well?
4. Are the cylinders kept at a suitable temperature?
5. Are the cylinders turned off after calibration?

B. Calibration

1. Has the chromatograph been calibrated in the last twenty-four hours?
2. Does the chromatograph calibrate in three attempts?
3. Are the methane/ethane peaks clearly separated on the chromatogram?
4. Are the heavy components responses clearly visible on the chromatograms
5. Are iso and normal butanes calibrated separately?
6. Are iso and normal pentane calibrated separately?
7. Are calibrations clearly marked on the chart recorders?

C. Maintenance, Operations and Spares

Time since the columns were last changed: _____________ days
Drilling fluid base liquid: __________________

1. What are the lowest attenuations being used?
2. Are the attenuations being marked on the chart recorders?
3. Are the chromatograms marked with depth and events?
4. Are anomalous gas events identified on the chromatograms?
5. Are spare columns present in the logging unit?

FID only: Block Temperature ___________ Sample Pressure ___________

1. Chromatograph set up to vendor's specifications?
2. Are there spare anodes and cathodes in the logging unit?

CCD/TCD only: Voltage ____________ Flow Rate ____________

Last time filaments were changed ____________ days

1. Chromatograph set up to vendor's specifications?
2. Spare filaments present in the logging unit?

## V Hydrogen Sulfide Detector

Time since last activated: _________________
Time since last calibrated: ________________
Date sensor last changed: ________________
Sensor Type: _____________________________

1. Is all ditch gas entering the logging unit continuously passing over the $H_2S$ detector?
2. Are there alarms in use?
3. Are there spare sensors in the logging unit?

## VI Drill Rate / Depth Recorders

System Type: MicroSwitch Hydraulic Crown Block DrawWorks

1. Is the system independent of the rig's depth system?
2. Does the system cover the entire “kelly” movement?
3. Is the system spanned and linear?

## VII Lag Determination

Time since an “actual” lag determination conducted: _________________
Last lag depth: _________________
Tracer used: ________________ Volume used: _________________
Gas detector Response: _________________ %EMA
Theoretical Lag strokes: _________________
Actual Lag strokes: _________________
Lag Time ________________ minutes at ______________ spm using pump # ______

1. Pump stroke counters present on every pump?
2. Are the counters independent of the rig system?
3. Are pump strokes used to lag samples?

VIII **Stand-Alone Gas Detector**

Vendor responsible for gas detector: ___________________________
Type of detector: ____________________
Time since last calibration: ______________________
Mud-Logging detector _______________ %EMA
Stand-Alone detector ________________ %EMA

1. Does the system have its own gas trap?
2. Is the system purged?
3. Is the system operating reliably?
4. Is a high gas alarm in use?
5. Is the high gas alarm set to current gas levels?
6. Is the chart recorder output clearly visible?

IX **Hole Monitoring**

Is the mud logging unit manned at all times?

A. Flow Show

1. Is a "flow show" installed and working?
2. Are alarms set close to operating conditions?
3. Are the alarms both audible and visible?
4. Are the alarms repeated outside the logging unit?
5. Does the mud logging crew appreciate the importance of the flow show sensor?

B. Pit Monitoring

Number of pits: _____________ Number of probes installed: ____________

1. Do all active pits contain probes?
2. Is volume or level displayed in the mud-logging unit?
3. Are the alarms set close to operating conditions?
4. Are the alarms both audible and visible?
5. Are the alarms repeated outside the logging unit?

X **Sample Catching Equipment**

1. Is an automated catching device in use?
2. Is a sample catching board installed?
3. Is the board cleaned after each sample?
4. Are samples routinely caught at the desander/desilter?
5. Are the samples being bagged and labelled properly?
6. Do the sample catchers understand the importance of their task?

XI **Cuttings Description Equipment**

1. Are the samples correctly washed in the muds base fluid?
2. Is the ultra-violet lamp working?
3. Are all samples screened for fluorescence?
4. Is the cutting solvent contaminated?
5. Are mineral identification chemicals used?
6. Is the microscope in good condition?

XII **Safety**

A. General Safety Aspects

1. Is the logging unit purged?
2. Does the logging unit have an emergency shut-down master switch?
3. Is there a usable emergency exit in the logging unit?
4. Is there a working internal ambient hydrocarbon detector in the logging unit?
5. Is logging unit access free of tripping hazards?
6. Is the logging unit appropriately cleaned and tidy?
7. Is the "No Smoking" policy observed in the logging unit?
8. Are fire extinguishers present in the logging unit?
9. Are the fire extinguisher inspections current?
10. Is there a usable first-aid kit in the logging unit?
11. Are the rig intercoms linked into the logging unit?
12. Does the logging unit have MSDS material for all chemicals?

B. Personnel Safety Aspects

1. Is there a life jacket available for each crew member plus a visitor?
2. Is there an emergency air pack available for each crew member plus a visitor?
3. Does the mud logging crew attend the rig safety meetings?
4. Are correct hard hats used at all times?
5. Is approved safety footwear used at all times?
6. Are safety glasses used?
7. Are hazardous chemicals handled appropriately?

XIII **Confidence Factor**

Can the crew be relied upon to provide responsible and reliable information?

Can the logging equipment be relied upon to provide information safely and efficiently?

Chapter 7

# Coring Procedures And Practices

## Introduction

Since most coring operations are conducted for geological information, the oil company's geology department will put forth their expectations on the type of data they want from the core. As a result, coring operations are undertaken for a variety of reasons. Due to the larger size of the sample, recovered cores allow more detailed assessment of rock properties. Primarily a core allows quantitative measurements of the following:

- Porosity - The volume of voids within a unit volume of rock.
- Permeability - The quality of the connections between the voids.
- Saturation - The composition of the fluids filling the voids.

Of a secondary importance is the additional information relating to formation boundaries, large scale sedimentary structures, undisturbed paleontological data, and the opportunity for uncontaminated geochemical sampling.

Most of the basics behind coring operations is presented in the *Advanced Logging Procedures Workbook*, however, it is best to review the two main reasons why coring takes place at the wellsite

1. **Stratigraphically** - the oil company will core a formation (generally accomplished on development wells)
2. **Hydrocarbon Shows** - the oil company will core any formation based upon unexpected hydrocarbon shows (generally done on wildcat wells)

Two types of coring operations are used:

- Conventional (at the time of drilling)
- Sidewall (while wireline logging)

### Conventional Coring

Cores can be cut as lithological confirmation (primarily at TD or in reservoirs), either as company policy or as a government requirement. This is especially true if basement is encountered very high in relation to the well’s prognosis. The Wellsite Geologist may be involved with decisions to include coring in the well program, and they should be aware that the decision to cut a core is a costly one, involving rig-time, extra contractors and laboratory analysis.

In order for coring to be successful, it must be recognized from the beginning that the objective of the coring operation is not to make hole rapidly, but to successfully obtain the core. Therefore, success is measured by core recovery. To achieve this, the Wellsite Geologist's duties will involve seeing that the core is cut at the correct depth, that it is retrieved properly, described, packed and dispatched in an expedient and safe manner. Make no mistake about it, coring operations are complex, and expertise is required to successfully cut and process a core.

### Sidewall Coring

Sidewall coring is a supplementary coring method used in zones where core recovery by conventional methods was less than expected or where cores were not obtained as drilling progressed. Sidewall coring is useful in paleontological work, for it is possible to get shale samples for micropaleo analysis at definite depths.

The sidewall coring device, is lowered into the hole on a “wireline cable” and a sample of the formation is taken at the desired depth. This is done by shooting a hollow “bullet” into the borehole wall, then pulling it out of the wall and up to the surface. There are as many as thirty bullets per gun, and since two guns can be used, up to sixty cores can be obtained during one run. If electric logs have been run previously, a spontaneous potential (SP) or gamma-ray (GR) curve is used to determine gun position by direct log correlation.

## Core Point Selection

Coring points are usually selected through correlation with known marker horizons, if a database exists. This practice is more common in development or delineation wells. Picking the core point is thus a matter of stratigraphic correlation. From seismic data and correlation wireline and mud logs, the approximate top of the reservoir will be known, and at the wellsite, correlation with offset logs is used to pick a point as close as possible to the top of the selected formation.

One drilling parameter that can be used at the wellsite is the drilling exponent. Since exponents have lithology and porosity dependent characteristics, when plotted on suitable scales, they can illustrate minor, but distinctive variations (related to lithology), which can be correlated with other logs from offset wells. The wireline log most used with drilling exponents is the sonic log.

If drilling exponents are not being calculated, correlation between the drill rate and offset logs is possible. This requires the geologist to monitor the well very closely, possibly requesting a slower ROP when approaching the potential core point. When using the drill rate, it is advisable to keep in mind that the drill rate will vary if the drilling parameters are altered. These variations will have to be taken in account. With this in mind, it is best to have the drillers agree to maintain steady drilling parameters when approaching the potential core point.

Even when drilling exponents and drill rate are used for correlation, confirmation of the core point generally requires gas or lithology data. This means frequent circulation of bottoms-up. Though this operation is expensive (in terms of rig time), the alternative of drilling beyond the core point, or coring too high, can be more expensive.

When the criteria for coring is met, then the decision to core can be made. If not, drilling is resumed until the correct depth is reached. In an exploration well, the instructions for coring may be rather general, in the form of “coring zones of interest” or “coring when good shows are encountered”. In these instances the geologist is required to discuss with the Operations Geologist the intention for coring prior to making the decision to core. Generally, the nature of reservoir lithology and the presence of hydrocarbons will have to be discussed. In any event, it is best to clarify what constitutes a good show in terms of percentages of fluorescence, types of fluorescence, gas shows in terms of percentages, before the possibility of coring occurs. The decision can then be left to the discretion of the Wellsite Geologist.

When the core point is reached, the usual routine is to stop drilling, flow check, circulate bottoms up and evaluate all the data available (cuttings for lithology, porosity, oil shows, gas shows, drilling exponents, ROP, torque, etc.) prior to making the decision to trip out of hole.

The actual coring depth is always confirmed by the Wellsite Geologist. Several criteria that will assist in selecting the coring depth are:

1. Review of the prognosis concerning the formation to be cored and comparison with data from the present well.
2. Review of the various correlation plots and logs.
3. Confirmation of the core point from circulation data, hydrocarbons and lithology from drill cuttings.

The correct depth must be confirmed. Any discrepancies must be resolved before the trip out begins. For this reason, it is common to “strap out” of the hole. Strapping out is the oilfield term for measuring the drillstring as it is tripped out. It is normally measured stand by stand using a tape measure (Steel Line Measure - SLM). This is a time consuming operation, and normally done when there is a unresolved discrepancy in depth, or when the depth must be accurately known. Coring being one operation when the exact depth is paramount.

One factor that can prevent a successful coring operation, regardless of the sophistication of the coring equipment, is hole problems. As with drilling operations, hole problems during coring should be a prime concern of the Wellsite Geologist. A complete review of correlation well reports and a review of previous bit runs can pin-point where and what type of hole problems may be encountered during coring. Typical problems include:

| | |
|---|---|
| Lost Circulation | Kicks |
| Sloughing Formations | Chert or Pyrite |
| Doglegs | Stuck Pipe |
| Key Seats | $H_2S$ |
| Unconsolidated Formations | Junk |

During coring, a careful watch must be maintained on the pit level, all coring parameters and gas values.

Adherence to the pre-well information and consistent monitoring of all aspects of the coring operations will prevent many borehole problems. For example, when coring in carbonates special considerations should be made regarding the likelihood of lost circulation. Consultation with the drilling department is required when lost circulation is a possibility.

## Coring Procedures

Prior to the coring process, there should be a wellsite meeting with all those involved in the coring operations. The drilling supervisor must ensure that:

- all drilling-related items in the prognosis are satisfactory, including the rig equipment, gauges and indicators
- the correct drilling fluid properties have been obtained
- the borehole is cleaned
- the core barrel has been assembled correctly

The Wellsite Geologist and mud loggers can assist in this preparation by supplying information about the hardness and abrasiveness of the formation, the degree of consolidation, the likelihood of fractures, and the possibility of hole problems, especially geopressure problems.

Arriving at the optimum coring parameters is based on many factors. In addition to those already mentioned, others include; the type of core bit being used, the coring parameters, positioning the core catcher for the best recovery, the length of the core to be cut, and BHA design. All have to be taken into consideration.

Most of these will have been decided upon prior to coring, however as each hole is different, there should be little hesitancy in modifying the parameters to meet any specific problems or to make the operations more cost-effective.

When the core barrel is nearing the bottom of the hole, if contact is made with cavings, it will be necessary to rotate and circulate (wash) ten feet at a time until the hole is clean. Be sure that all measurements are correct to determine the bottom has been reached. Abnormally high pump pressures can indicate that there is debris in the core barrel or core catcher, which must be pumped clear before coring can commence. Once bottom is reached, pick up off bottom one to two feet and circulate with sufficient annular velocity to condition the mud and keep the hole clean. This is done with the ball out, for 15 minutes to one hour, or longer if necessary.

After the bottom is cleaned, the drillstring should be raised several feet off bottom while circulating to ensure the inner barrel is clean. The kelly is then raised to the first joint of drillpipe. Circulation is stopped, the kelly is removed, and the ball is dropped into the drill pipe. Once the ball has been dropped, the kelly is replaced and circulation started to pump the ball down at a good rate. While the ball is falling, record the pump rate and standpipe pressure. As the ball nears the setting position, the pump rate is reduced to allow the ball to seat properly. As soon as the ball is seated, the drillstring is returned to bottom. Once the ball is seated in the check valve, the circulating fluid is diverted through the circulating ports between the inner and outer barrels and out the discharge ports in the bit face, in the conventional manner.

It is important to know the type of bit that has drilled the previous section of hole. Each bit type cuts in a particular pattern, and for proper seating of the core bit on bottom, this hole pattern must be taken into account. Once on bottom, rotation should begin slowly (30-40 rpm), and weight added in increments of 2000 lbs. Weight-on-bit, rpm, and fluid volume should be gradually increased until the optimum coring parameters are reached.

The first few inches of actual coring are the most important because:

- it will determine the optimum coring parameters required to cut and recover the core
- it will signify if problems are going to occur during the coring process
- it will verify that all the planning and precautions taken have proven worthwhile

While the core is being cut, careful monitoring of the coring variables is important to detect problems which may cause a halt to the coring operations. Many of the parameters monitored will not only be instrumental in determining how successful the present coring operation is, but will be used to assist in the planning of future coring operations.

Coring parameters (weight-on-bit, rotary speed, flow rate, and standpipe pressure) must be closely monitored and held as constant as possible. It is advisable to perform tests on the WOB, RPM and GPM until optimum coring rates and conditions are found.

Once found, these parameters should be held constant until there is a definite change in the coring rate or the entire core is cut.

Sudden changes in the coring parameters may damage the core bit or cause the core to break. Broken rock fragments can then lodge in the core catcher, jamming the core, and bringing the coring operations to a halt.

As mentioned earlier, during the trip-out prior to coring, the drillstring may be strapped to determine a “Total Measured Depth” for coring. If there is one hundred percent recovery, the depth and footage can be reliably determined. Unfortunately, there are several problems which can occur during coring which will result in inaccurate depth measurements.

1. Low weight-on-bit is used during coring, which means is a larger surface hookload. This will result in greater drillstring stretch. If drillstring stretch is not taken into account, a depth error will result.
2. If the weight-on-bit value is changed during coring, this will result in changes in pipe stretch and kelly height. A decrease in kelly height, due to increasing weight-on-bit may be interpreted as increased rate of penetration, when the only thing happening is a reduction in pipe stretch. These errors usually occur when coring is started and ended, and when a connection is made. These errors are normally seen when a 30 foot core barrel appears to cut a 32 foot core, or the barrel appears to jam at 28 feet, when 30 feet was actually cut.
3. Lost core pieces from the bottom of the core barrel, especially when making a connection or when tripping out, can either be drilled up when coring resumes, or can reenter the core barrel as whole core or broken fragments. This will result in a loss or gain in the length of core recovery, making the actual length difficult to determine.

Once coring is completed, the depth and core length which is finally reported will be a compromise between the drillers depth, the mud loggers figures, and the recovered core length. Though this figure may be imprecise, it is generally accepted. Whatever figure is decided upon, that figure should appear on all reports, logs, and core annotations.

During the cutting of a core, have the mud logging crew catch samples at a smaller than normal interval. If coring is slow this may be as small as 2 ft or 1 m. In the event of poor recovery these cuttings may be the only lithological evidence available. The monitoring of gas and cuttings during coring will also give the first indication of reservoir quality.

The fluctuations in weight-on-bit, as mentioned above, will result in inaccurate drill rate measurements. Drill rates will be erroneously high when weight-on-bit is being applied, and low when the weight-on-bit is being drilled off. When the weight-on-bit is held relatively constant, good rate of penetration data can be recorded. During coring operations, the rate of penetration is recorded at one foot intervals and smaller intervals can be monitored if necessary. With relatively constant drilling parameters, minor variations in the drill rate can be diagnostic in changes in the formation characteristics (i.e. hardness, fractures, etc.).

Careful monitoring of the depth and drill rate will indicate when a complete core has been cut. When the core barrel is filled, the rate of penetration will decrease rapidly. When this occurs, the bit should be allowed to drill-off the weight-on-bit at a slightly increased rotary speed. This will ensure a clean cut at the bottom of the core. The bit is then slowly picked up off-bottom with circulation continuing.

When picking up off-bottom, with the full core barrel, the brake should be operated gently and the weight indicator watch carefully. If the core catcher operates properly, an overpull will be observed first. When the core breaks, the weight will fall back to normal. Overpull should not be allowed to exceed 30,000 lbs above the string weight, or the maximum rating of the safety joint (whichever is less) since this can damage the core barrel or cause the drill string to back-off from the core barrel. If the core cannot be broken, the brake should be set with 20,000 to 30,000 lbs overpull, and the core rocked with small back and forth movements, using the rotary table, until the core breaks.

When the desired formation has been cored and coring operations are concluded, it is time to bring the core to the surface. Fast movements and sudden stops during the trip out can cause the core to fall out of the core barrel. To prevent this, tripping out of the hole is performed so as not to cause the drillstring to rotate or to move up or down suddenly. Spinning chains are normally used to break-out the pipe. It is also general practice not to circulate returns prior to tripping out with the core.

During the trip to the surface, there will be a steady and constant reduction of pressure within the core, until the core is at atmospheric pressure (14.7 psi) at the surface. This reduction in pressure will cause dissolved gases to be released from solution and cause a portion of the contained fluids to be expelled from the core. At the same time, oil will undergo some shrinkage as its dissolved gas is released.

## Core Retrieval

The type of core being cut will have a direct bearing on the handling procedures once the core is on the surface. Security precautions should also be taken into consideration. Coordination between several groups; the drill crew, the Wellsite Geologist, the coring company, and the core analysis company is necessary to get the core collected and shipped to the laboratory quickly, conveniently, and in good condition.

Most conventional cores are handled on the rig floor. The inner core barrel is suspended in the derrick and raised periodically to allow the core to slide onto the rig floor to be collected. Some wireline retrieval core are caught this way, and broken into lengths for easy handling.

If there are problems with the core sticking in the core barrel, or if specialized coring has been done (sponge coring, pressure coring, rubber sleeve, special liners), the core barrel will have to be laid down on the cat walk. Wireline cores are often laid down this way to facilitate removal. To prevent small diameter cores from breaking, they are placed into a rigid container before being laid down.

Once on the catwalk, lifting subs are removed and a rubber plug or core pusher may be inserted in the top of the barrel. A pump-out connector may be made up on the inner core barrel and high pressure air or water is used to pump-out the core.

The main concern of the drilling crew is to either resume drilling as soon as possible or to re-dress the core barrel so it is ready for another core. It is the Wellsite Geologist's responsibility to retrieve the core correctly and allow these operations to continue as soon as possible without jeopardizing the quality of the core. A methodical approach is required, do not rush the removal or initial inspection of the core.

The Wellsite Geologist should enlist the help of the mud logging crew and delegate certain aspects of the retrieval to them. Ideally, a work area adjacent to the mud logging unit should be prepared, with The work area being covered, well lit and "safe" (in so far as electrical equipment such as the U.V. lamp and wax bath are concerned). It may be necessary to obtain a "hot work" permit for the wax bath. If possible, a bench should be utilized that allows the full core to be laid out. In offshore locations, space constraints may make this difficult, but the Wellsite Geologist should strive for as large an area as possible.

A supply of core boxes, marked Top and Bottom and numbered should be present near the drill floor prior to the core reaching surface. Some sample bags, a hammer and a note book should also be present on the rig floor. When the core reaches the surface the Wellsite Geologist should supervise the catching of the core. **At no time should you place a hand under the core barrel!** If the core leaves the barrel in a continuous piece it will have to be broken using a hammer in lengths of less than 3 ft, so it will fit into the core boxes. Retrieval rate is governed by the rate at which you can catch and box the core. Should the core come out fragmented, ensure that the core is not allowed to come out faster than you can catch the pieces and correctly orient them in their boxes. It is essential that you do not let the drill crew hurry you during retrieval.

The core must be retrieved so that no confusion occurs as to the orientation of fragments. Do not let other people help you by picking up pieces of the core as they may mistakenly up-end them. Any rubble or fragments that falls out of the core barrel should be placed into sample bags and put into the approximate position within the proper box. The first part of the core to be retrieved will be positioned at the bottom of box #1. The last part of the core retrieved will be at the top of the last box. If the work area is a long way from the rig floor it may be useful to have a pallet on the rig floor that the catching boxes may be placed on, and a crane used to move the boxes. Otherwise, have the mud loggers carry the boxes to the work area.

In the designated work area a second set of core boxes should be assembled, which are also numbered and labeled. More sample bags should also be available, a supply of clean rags, a measuring tape, some marker pens, a notebook/clipboard and sufficient sealing and wrapping supplies. Having retrieved the core in the catching boxes, these will be taken to the work area. The catching boxes should then be assembled with the respective core boxes. The core boxes at the work area will become the cores final resting place.

At this point it may be necessary to make a decision to resume drilling or continue coring. While recovering the core, the Wellsite Geologist should be making an assessment of the lithology. Small samples may be taken from the base of the core for examination under the UV lamp and microscope. If the decision to resume drilling or coring is in doubt, or the Operations Geologist has requested notification, the following information should be relayed:

- Depth interval of core
- Recovery of core
- Lithology of core
- Hydrocarbon shows observed

The core is then cleaned with dry rags, unless specifically instructed to use damp rags (to remove the filter cake). The core is then re-aligned, closing any gaps or fractures so that an accurate length measurement can be made.

To measure the core, start at the very top of the core (at the top end of the highest numbered box), because this will be the depth at which coring commenced, using the drill crew depth figures. Markings on the core is usually conducted with indelible felt markers. Initially, two different colored lines are run down the length of the entire core, marking each piece, arrows are placed along these lines pointing towards the top (the usual colors are red, on the right, and black on the left). These lines ensure that all core pieces remain in the correct orientation to each other. Once this has been completed, the core may be depth marked.

From the top of the core, markings are made to the nearest foot and to the end of each box interval. These markings should also be made on the inside of the box at the same level. This process continues until the bottom of the core is reached. It is generally assumed that if any portion of the core is missing it is lost from the bottom of the core. If the core recovery is found to be greater than presumed cut (i.e. 110%), the recovery is treated as correct and the depth of the next core, or drilling is adjusted.

If the core is required for engineering data, such as fluid saturations, it may be necessary to seal the core immediately in wax. If wax baths are required, the core is first wrapped in plastic cling film or saran wrap, then wrapped with heavy duty aluminum foil. Depth markings and core tops are then marked upon the foil with an indelible marker. A piece of string is tied around the core to enable the core to be dipped into the wax bath to seal the core entirely. The core is then removed from the bath using the string and hung up to dry. When dry, the string is cut and that area wax sealed to prevent fluid leakage.

If sealing procedures are not used, then a detailed core description can take place. Core descriptions will be similar to cuttings descriptions, except that larger scale sedimentary features such as bedding, formation contacts, fractures and macrofossils can be described. Fragments may be removed from the core at intervals to allow for microscopic examination.

Hydrocarbon show evaluation will also be similar to that of cuttings, with the addition of oil and gas bleeding from the core and petroleum odor being described. Once descriptions are completed, the core can be sealed with cling film and then wrapped in aluminum foil. This is especially important if the core is fragmented.

## Packing The Core

Once the core has been described and wrapped, it is placed back into it's respective boxes and the boxes filled with either paper or rags to ensure that the core does not shift within the box during shipment. The outside of the core boxes should be marked with the following information:

- Well Name
- Top and bottom number (i.e. 1T, 1B, 2T, 2B etc.)
- The address of the recipient.
- The core number (i.e. core #1, core #2)
- The box number and total number of boxes (i.e. Box 1 of 7, Box 2 of 7)

Depth data is not normally put on the outside of the boxes. The core is then weighed and the total weight of the core calculated for freight manifests. Finally, the Operations Geologist and the addressee on the core boxes should be notified immediately once the core leaves location. This will facilitate customs clearances and any other potential problems.

If a fiberglass or metal liner is used, the recovery process and packing procedures are somewhat different. The liner is laid down on the catwalk and cut into 3 feet (1 m) lengths, after measurement and marking. Core chips are removed from the cut sections for “quick look” inspection. Once the chips are taken, caps are fitted to the ends of the liner and taped on. The liner lengths are then packed in core boxes or placed into core crates.

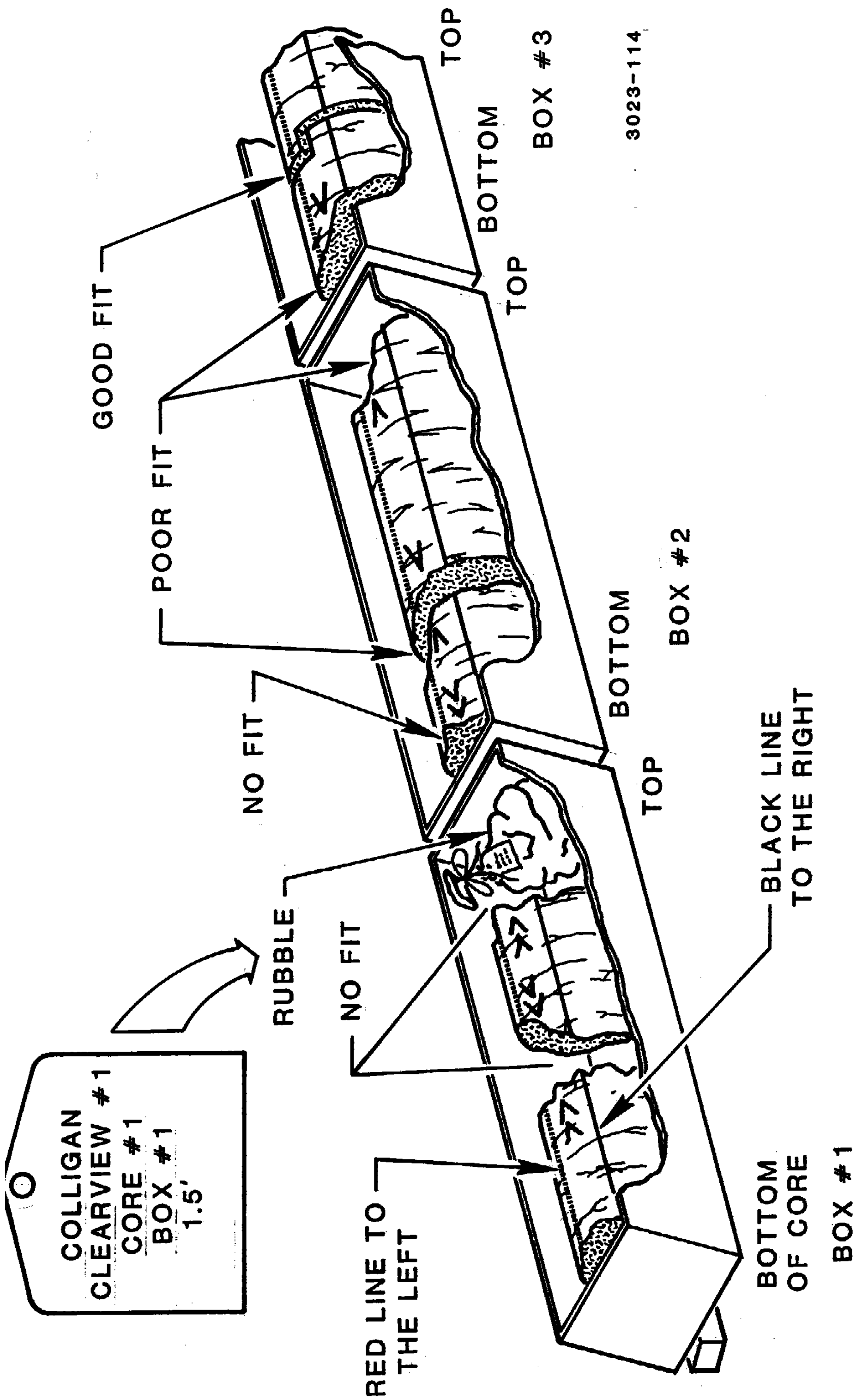



Figure 7-1: Labeling and Packing a Core

Chapter 8

# Witnessing Wireline Logging Runs

Even though the Drilling Superintendent or company man at the wellsite is in overall charge throughout wireline logging operations, they should be assisted and advised by the Wellsite Geologist and the logging engineer throughout the logging operations. When given the authority, the Wellsite Geologist will personally supervise all petrophysical or sampling operations.

To ensure satisfactory results, the Wellsite Geologist will be responsible for:

- Safety aspects during logging operations
- Meeting the data requirements of the wireline logging program
- Organizing personnel and equipment logistics
- Data accuracy
- Accurate records of events during logging operations

## Pre-Run Preparations

Prior to the actual drilling of the well, the wireline logging program will have been prepared by the oil company. The oil company personnel involved in the preparation will be drilling engineers, geologists, geophysicists, and reservoir engineers. Any significant deviation from the established program must be authorized by the local oil company management, which will generally be the Operations Geologist.

### Onshore

Discuss the logging program and any special requirements with the Operations Geologist or petrophysicist. Obtain log prints of any offset wells for correlation purposes.

### Offshore

Discuss the logging program with the logging engineer and ensure that all the necessary tools, back-up tools and relevant fishing tools will be available on the rig in good time.

Ensure that all logging tools and their back-ups are tested on the surface, and that any problems or faults are noted and rectified.

If fluid samples are to be taken, ensure that an adequate supply of containers (plastic bottles for water and 1 gallon metal cans for oil) are on hand during the operation. Also, ensure that liquid measuring vessel, a gas meter, and resistivity meter are available.

Ensure that the log header information is correct. This includes:

- Well Name
- Field Name
- Latitude and Longitude of Well
- Derrick Floor and RKB Elevations
- Seabed Depth
- Driller T.D. and Bit Size
- Casing Sizes, Weights, and Shoe Depths
- Mud Type, Density, Viscosity, pH, and Fluid Loss
- Time Circulation Stopped

In wells drilled with a water based mud, have the mud logger supply the logging engineer with samples of mud, filtrate and filter-cake, taken from the flowline prior to circulation being stopped. The Wellsite Geologist should be present when the $R_{mf}$, $R_m$, $R_{mc}$ and surface temperature are measured.

If data transmission is required, perform a transmission test before logging and ensure the receiving computer center is aware of the required log distribution. Make sure passwords or userwords have not been changed and that the computer center will be functional when you need it.

## Procedures

Before the logging runs begin, ensure that all tripping related work is completed and the rig floor is as clean as possible. The drilling fluid level should be checked at the bell nipple before, during, and after logging operations, and that this fluid level is maintained throughout.

The wireline logging engineer should be ready to rig-up as soon as the pipe is out of the hole. On floaters, make sure the sheaves are compensated for rig motion.

Review with the logging engineer the previous log suites, or correlation logs to determine; expected SP values in clean sands, Gamma Ray values in shales, and expected resistivities and porosities in zones of interest.

## Depth Control

Wireline log depths are usually the standard depth reference for all future operations in the well, and all evaluations of that well. It is essential that every effort be made to ensure that the depth is as accurate as possible.

On any logging suite, the primary control is the logging contractor's depth measurement system, with a secondary check being the casing shoe depth, and the cased hole overlap from a previous logging run.

Depths measured with drill pipe may be significantly different than wireline depth, especially in deep and deviated wells. This is because the driller does not take drill pipe stretch into account, so the drillers T.D. may be different. The borehole may also fill up with cavings, which will also cause discrepancies in the wireline depth. Depths measured using casing information are usually much closer to wireline depths. The driller, mud logger and wireline engineer should agree within 2 ft at 5,000 ft, and within 5 ft at 10,000 ft as to the correct depth.

All formation tests, sidewall samples, and CBL runs are generally tied to the depths from the density log.

### First Survey

On the first logging run into the well, the tool should be zeroed at the RKB or the Derrick Floor. Following the standard checks on the cable mark, the tool should be stopped on entering the open hole and the casing shoe logged. Any discrepancy of more than 2 ft at 5,000 ft, and 5 ft at 10,000 ft between casing depth and log depth should be investigated.

For this reason it is useful to retain the casing talley at the wellsite, and forward copies of the list to shore in the event of such a depth discrepancy. If the reasons for the discrepancy are not clear, the log can be run and the surface zero depth checked at the completion of the run. If any depth adjustments are deemed necessary after the logging run, they should be recorded in the “Remarks Section” on the log header, and applied before any playbacks, tapes, or data transmissions are made.

### Subsequent Surveys (Same Interval)

Subsequent logging runs over the same interval should be tied into the first survey, and any depth adjustments, applied before playback, field tape production, or data transmission.

### Subsequent Surveys (Deeper Intervals)

All subsequent logging runs should be on absolute depth. In addition to the above checks, deeper logging runs should include a section of overlap with a “through-casing” Gamma Ray. If this overlap agrees within the tolerances stated previously, after a stretch correction, the depths should match and logging can continue. If a depth discrepancy is outside the tolerances, the reason for this should be investigated.

If it is proved that the new depth is more accurate than previous depths, this should be noted in the “Remarks Section”, and the survey run with a through-casing Gamma Ray recorded over the previously logged intervals for correlation. If the shallower logged interval is still in open hole, the complete interval should be re-logged to compensate for the depth adjustment.

As an additional check on depth, a short section of log over the casing shoe should be recorded on the first descent of every log suite, after stretch corrections have been made, but before tieing-in and proceeding to T.D. As stated above, the casing shoe depth should agree with the driller depth within 2 ft at 5,000 ft, and 5 ft at 10,000 ft.

### Investigating Depth Discrepancies

In the event that the driller's and logger's casing shoe depths are substantially outside the accepted tolerances, the following checks should be undertaken:

1. Were the logging contractors depth control procedures applied correctly? Was an excessive shift applied to tie-in to the previous run?
2. Check the addition on the casing talley.
3. In the event that neither of the above pin-point the discrepancy, the problem should be discussed with the client's petrophysicist, and the possibility of running a CCL inside the casing to surface, and checking this against the talley sheet. With this in mind, a CCL should be included in the first or second tool string in each logging suite.

### Change of Rig or Derrick Floor Elevation

In the event of a change of rig or adjustment in the Derrick Floor elevation during the course of the drilling operations, all log depths should still be referenced to the original Derrick Floor elevation.

In the case of development wells drilled from a jack-up, a permanent datum point should be established on the wellhead or casing hanger. The original RKB height above this datum point should be reported on the log headings. The current RKB (or deck) height should be noted in the “Remarks”, and the difference added or subtracted when zeroing the tool at the surface before logging.

In the case where the wells are drilled from floaters, mean sea-level will remain the permanent datum point.

### Cased-Hole Operations

Cased hole logging runs, which include a Gamma Ray, should be tied into the appropriate open-hole Density-Neutron log.

Logging runs, without a Gamma Ray, should be tied into the CBL using the CCL. If a pup joint is present in the casing string, it should be logged and presented on film; if not, enough casing joints must be logged above and below the zone of interest to avoid ambiguity.

### Bottom Hole Temperature

At least two maximum reading thermometers should be run with each logging suite and all temperatures recorded for each logging run, including RFT, Dipmeter, and CBL. The elapsed time from stopping circulation until tool on bottom should be recorded.

If a real time temperature measurement is made, temperatures should be recorded on tape for one log over the complete logged interval.

### Log Numbering Sequence

Unless the client stipulates otherwise, logs should be distinguished by numbers and letters, the numbers referring to the overall job and the letter to the times that particular service has been run. Runs which produce no final print (e.g. tool failures), are not allocated a run number.

| **Top Hole** | |
|---|---|
| DIL/Sonic/GR | Run 1A |
| **Intermediate** | |
| DIL/Sonic/GR | Run 2B |
| Density Neutron | Run 2A |
| **Total Depth** | |
| DIL/Sonic/GR | Run 3C |
| Density Neutron | Run 3B |
| DLL/MSFL | Run 3A |
| Dipmeter | Run 3A |
| RFT | Run 3A |

### Repeat Section

A 200 ft repeat section is required on all logs. Ideally, this should be run at, or near, the casing shoe on first entering open hole. This will allow the maximum time to elapse in order to check tool stability. Alternatively, consideration may be given to running the repeat section over any reservoir interval. It is advisable to run the repeat section prior to the main log, so any tool problems can be immediately apparent.

If running logs in drillpipe (high angle wells), it is best to log down and log up without repeat sections.

### Calibrations

Calibration records must be made *before* and *after* each logging run. Records of these, together with the shop calibration record, should be attached to the log films before printing.

### Depth Scales and Curve Line Types

Log scales will vary, depending on the units required. Imperial units (1:240 and 1:1200) or metric (1:200 and 1:500) are common. The following are the basic line types for the curves:

| Curve Line | Line Type |
|---|---|
| Gamma Ray | Solid |
| Caliper | Dashed |
| Density | Solid |
| Density Correction | Dotted |
| Neutron | Dashed |
| Deep Resistivity | Dashed |
| Med/Shallow Resistivity | Dotted |
| Micro-Resistivity | Solid |
| Sonic | Solid |

A tension curve should be presented on every log run.

### Remarks

All relevant comments and remarks should be recorded in the appropriate section on the log heading.

If logging in drillpipe, keep a close eye on the head tension (AMS tool) as this will indicate any compression of the drillstring, if tight hole or ledges be encountered. Always check the seating of the wet connectors and cable tension prior to powering up, as a check for electrical contact.

## General Quality Control and Procedures

### Logging Down

The Induction/Sonic log should be logged down, at least over any zones of interest. There is no need to reduce the running speed, and the down log should not be presented, unless no up log is obtained.

In difficult holes (highly deviated/hot) consideration should be given to logging the Density/Neutron down. In this case the running speed will need to be reduced to 3000 ft/hr or less, and the Gamma Ray log is not normally valid due to formation activation.

### Logging Speed

All logs over any reservoirs should be run at 1800 ft/hr, and at no more than 3000 ft/hr, above or below the zones. Some of the newer spectral tools require logging speeds in the range of 600 ft/hr to 900 ft/hr. In washed-out holes, the log quality can be improved somewhat by slowing down the logging speed.

In logging the Gamma Ray to surface, running speed can be increased over long intervals with little character (i.e. salt). However, make sure that the speed is reduced well below expected formation tops.

### Cement Bond Log

This log should always be run from TD to a minimum of 100 ft above the top of the cement.

### Repeat Formation Tester

- Pressure

    1. In all reporting of measured pressures (i.e. Pretests), care should be taken to record the correct units (i.e. absolute (psia) or gauge (psig)). Quartz pressure gauges normally record psia, however this may have been modified by the contractors software.
    2. If quartz gauges are run, they will take time to thermally stabilize. This will normally involve a wait of one-half to three-quarters of an hour at the casing shoe when first entering the hole. At each measuring depth, a short wait may also be necessary. As a guide, sufficient stabilization will have been achieved if measured hydrostatic pressure agrees within 1 psi, before and after the formation measurements. Most tools have a resolution of 0.01 psi, but stabilization to less than 1 psi is often unrealistic.

3. The formation pressure should be allowed to build up until it is constant to ± 0.5 psi for two minutes, unless hole conditions dictate otherwise.

4. To prevent hysteresis effects, pressures should be measured going into the hole (i.e. with pressures increasing), although should checks be required on the way out, they are usually OK.

5. During testing, mud hydrostatic and formation pressures should be plotted against vertical depth. The mud pressures should lie on a straight line with a gradient consistent with the reported mud densities. Formation pressures should be less than mud pressure and should be consistent with the reservoir fluids, horizontal pressure barriers and expected depletion.

6. When formation pressures are much higher than hydrostatic pressure, “supercharging” should be suspected (higher pressures due to ECD will affect low permeability formations).

7. Tests which do no follow the expected trends should be repeated.

8. Ensure that during pressure testing the driller does not adjust the mud level in the hole. If they do, it should be reported and noted in the “Remarks” section.

9. If you have a time limit for each Pretest, because of potential sticking problems and the formation has low permeability, it is not uncommon to have the pressure test chambers partially blocked-off. In the RFT tool there are two 10cc chambers and these can be blocked-off to give a total of 15, 10 or even 5 cc. However, if the size of the Pretest chambers are reduced, the results of calculated permeability will be erroneous to some degree.

- Fluid Samples

1. Unless otherwise instructed, all wireline formation fluid samples should be taken as segregated samples with the first portion of the flow being directed into a larger of the tool’s two chambers. In order to obtain as representative a sample as possible in the smaller segregated chamber, the flow should be switched to this chamber before the pressure has fully built-up in the large chamber (in other words, before flow has stopped and allowed filtrate invasion to recommence). Ideally, the flow should be switched immediately and any pressure build-up noted while filling the first chamber.

2. Pressure should be allowed to build up to a stable formation pressure in the segregated chamber.

- Sample Analysis

  1. The best wellsite estimate of salinity in water samples is obtained by resistivity measurements. This can be performed by the mud logger or wireline engineer. Resistivity and temperature should be reported.

  2. If a measurement of chloride content is made by chemical titration, this should be reported as Chloride Content, in ppm. This can be performed by the mud logger or mud engineer.

- Data Presentation

  Log prints of wireline formation test data should display motor speed in Track 1.

  If a quartz pressure gauge is run, strain gauge pressures should still be reported, preferably in psia, either digitally, alongside the quartz gauge pressures in the "depth" track, or on a separate print.

### Sidewall Samples

- In wells with a borehole temperature greater than 300°F, the guns batteries should be replaced after each sidewall coring run.
- If the sonic and density logs suggest hard or dense formations, notify the logging engineer to see if extra charges or different bullets are required.
- To save rig-up time, in case of tool failure or poor recovery, a fully armed back-up gun should be ready on the surface during each run.
- Watch out for cross-contamination upon recovery of the plugs from the bullets.
- See Figure 8-1 for sidewall bullet characteristics for various lithologies

| **Lithological Group** | **Sonic Reading** (µsec/ft) | **Ring Size** | **Bullet Type** | **Load (gm)** |
|---|---|---|---|---|
| | >85 | Large/Reversed | Combo | 10.0/12.0 |
| Arenaceous | 72-85 | Small | Combo | 12.0 |
| | <72 | None | Combo/Hardrock | 12.0/13.5 |
| | >105 | Large | Combo | 12.0 |
| Argillaceous | 84-105 | Small | Combo | 12.0 |
| | <84 | None | Combo | 12.0 |
| Carbonate | >62 | None | Combo/Hardrock | 12.0/13.5 |
| | <62 | None | Hardrock | 13.5 |

**Figure 8-1: Bullet Requirements for Various Lithologies**

**Note:** *If the differential pressure is greater than 800 psi, add a ring or replace small ring with a large ring*

## Quick Look Log Analysis

Upon completion of the first logging suite, the Wellsite Geologist should carry out a quick-look analysis over any potential reservoir intervals (see Appendix C). The logs should be correlated with the mud log and offset logs. The results then reported to the client's office, and should include:

- Top and bottom of each reservoir interval, in feet
- Net footage (thickness) for each reservoir interval
- Type of hydrocarbon and hydrocarbon/water contact
- Average and range of calculated porosity and water saturation values for each interval
- $R_w$ in the clean, water-bearing formations

If the log scales are suitable, overlays can be used, otherwise use the charts available from the wireline logging company. Remember, your results will be semi-quantitative in clean formations and only qualitative in shaly or gas-filled formations. These results, however, are generally satisfactory for well site evaluation.

The oil company will usually have a computer analysis performed on the log data after the logging operations.

## Communication

During wireline logging operations, the Wellsite Geologist reports directly to the client's drilling supervisor, and must ensure that the drilling supervisor is aware of the status of any operation involving the borehole at all times. They must inform them immediately of any deviation from the planned operational program.

The primary onshore technical contact is the client's petrophysicist. Prior to the job, the petrophysicist will prepare the logging program, including any special instructions, which can be hand-carried or sent to the rig via fax.

Significant modifications to the program (i.e. extra tool runs or cancelled runs), must be confirmed through the Operations Geologist. The Wellsite Geologist and drilling supervisor must ensure that both operations and the petrophysicist are aware of, and have agreed to, such changes.

Detailed operational instructions, such as wireline pressure and sample depths, will be communicated, or at least confirmed by fax, whenever feasible. Otherwise, they can be communicated by telephone.

## Log Quality Control

The Wellsite Geologist should have in their possession copies of any offset logs, and the new logs should be critically compared with these, paying particular attention to shale beds and other marker intervals. These are used to check for possible shifts in tool responses. Any discrepancy should be investigated, and if an acceptable explanation is found it should be noted in the "Remarks" section, otherwise consideration should be given to re-running the survey with a back-up tool.

For more details on Log Analysis refer to Appendix C or the *Advanced Wireline & MWD Procedures Manual*.

General Quality Control checks include:

### SP Log

- There should be no evidence of noise, magnetism or other unnatural effects
- The curve should look reasonable opposite highly resistive formations
- The baseline should not have unreasonable drift

### Laterolog

In the Dual Laterolog, the deep and shallow curves should track one another in shale sections

### Induction Logs

- The conductivity should have sufficient amplitude in water zones
- It should not have spikes at boundaries of high resistivity formations
- The resistivity values should correspond to conductivity values
- The curves should track one another in shales

### Velocity Logs

- Check the $\Delta t$ values in formations of known composition (i.e. anhydrite)
- Ensure the $\Delta t$ value in casing is 57µs/ft
- Check for cycle skipping

### Nuclear Logs

Check porosity and density values in formations of known composition. Repeatability on these logs should be good, but they will never be perfect.

## Data Distribution

Data should normally be transmitted as soon as it is available (i.e. while pulling out of the hole).

Normally the open-hole porosity and resistivity logs will be transmitted. To save on transmission time, do not include the repeat sections and calibration data.

After transmission, the same logs should be faxed to the operations center, to the attention of the drilling superintendent.

Field prints of the logs should be produced on site, or after logging. These will include the repeat section, calibration data and full heading information on a non-API format. For non-transmitted logs, such as RFT and dipmeter, field prints plus one sepia should be produced. One set of prints should be retained on the rig, one set should be sent to the drilling superintendent, the remaining sets and the sepias should be sent to the petrophysicist.

The logging engineer will retain the films and tapes, awaiting final instructions from the petrophysicist. Finalized logs will be produced with an API heading to distinguish them from the transmitted and field prints.

A “Daily Logging Operations” fax should be sent to the client's petrophysicist and to any partners at 0600 every day during logging operations, and on the conclusion of the job. Information should include:

1. Title - “Wireline Logging Operations:” with well name, time and date
2. Activity Summary - Tabulate time commenced, duration, activity. Include any relevant details (i.e. logged intervals, any downtime, extra repeats, etc.).
3. Quick Look Analysis - Of all potential reservoir intervals, giving top, bottom, net, average, and range of porosity and water saturation.
4. RFT Summary (when run) - Tabulate test number, depth, hydrostatic pressure before and after, formation pressure, and remarks (i.e. permeability, supercharged, seal failure, sample). For samples, report pressure at surface, fluid recovered, water resistivity. Also include mud and formation fluid densities.
5. Sidewall Cores (when run) - Tabulate sample number, depth, recovery and brief description.
6. Future Program - The remaining logging operations.

This is only an example format, but the above information should be supplied in any client report. Include any other points of interest.

## Time Breakdown and Downtime

A logging time breakdown form should be completed. Times should be recorded to the nearest 15 minutes. Rig-up and running times should be recorded separately.

Running time is taken when the tool leaves the surface until it is back on the drill floor. The rig-up time for all but the last tool can be included in the rig-up time of the next tool.

Downtime should be recorded in a downtime column, as well as in the operating time column.

This form is the responsibility of the logging witness, even though separate breakdowns may be kept by the logging engineer and the driller. There is no need to reconcile these on the rig.

The complete time breakdown forms should be forwarded to the petrophysicist.

**Example Logging Time Breakdown Report**

Well:____________________Depth:_____________Page ____ of ____

Date Logging Started: ____________Date Logging Finished:__________

| Date | Log | Run No. | Rig-Up/ Run | Start | | Finish | | Operating Time | | Down Time | | Remarks |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Hr | Min | Hr | Min | Hr | Min | Hr | Min | |
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1. Report times to the nearest 15 minutes totals
2. Report rig-up time separately for each run
3. Include downtime in operating time
4. This form should be completed independently by the witness. Any reconciliation with other time breakdowns will be carried out in the office.

Operating Time: ________

Down Time:____________

% Downtime: __________

(DT/OT x 100)

•Notes•

# MWD Logging Runs

## Introduction

The quality control of MWD operations requires many of the safe guards which are performed in wireline operations. Care and scrutiny must take place from the time the tools are on the rig, through their downhole operations, until the tools are returned to the service company's base. The size, weight and expense of MWD tools necessitate that quality control and safety requirements be monitored to ensure there is no damage to the tools, or to the individuals moving those logging tools.

MWD log responses are becoming very similar to wireline tool responses, and many MWD companies have their own “Log Interpretation Charts” for their inventory of tools. Interpretation fundamentals require the Wellsite Geologist to remember that the tool's response, and ultimately the curve drawn on the log, is “real time” (and all that this entails) as opposed to post-drilling responses from wireline logs.

## Benefits of MWD

The benefits of MWD services fall into three distinct areas; directional drilling savings, real-time or near real-time formation evaluation, and the resulting safety aspects concerning drilling optimization.

### Directional Control

Using multiple accelerometers and magnetometers, MWD surveys provide much more accurate determination of the drill bit's location in the borehole. These survey's take place during a connection, so there is much less survey downtime, reducing the risk of differentially sticking the drillstring. Taking surveys more often results in reduced dogleg severity, reduced rig time and costs of drilling motor correction runs, and savings due to not running multishots prior to setting casing

### Formation Evaluation

Real time logging provides quick evaluation of formation data resulting in fast, accurate correlation decisions. Information can be gained before significant hole deterioration takes place, prior to significant filtrate invasion, and the hole is logged and information gained before the possible loss of the hole.

There will also be better bed resolution due to the slower logging speeds, because logging speeds are based on the drill rate. Present FEMWD information includes:

- Gamma Ray, for correlation and shale volume determination
- Resistivity, for Rt, invasion and water saturation, and pore pressure calculations
- Density, for bulk density, porosity and water saturation
- Neutron Porosity

In many cases, this real time information can reduce the need for top hole wireline log runs, and the real time pore pressure information can extend or eliminate planned casing strings. Both being tremendous cost saving measures.

### Drilling Safety and Optimization

The information provided by MWD allows for improved drilling efficiency, improved bit performance and coring point location, by indicating formation changes. The information allows for improved pore pressure evaluation, one of the safety aspects of MWD.

## Tool Quality Control

The Wellsite Geologist must be involved in the quality control aspects of the MWD tool during its stay at the wellsite. Most MWD tools are much more expensive than their wireline counterparts. In addition, the oil company will usually have to pay a daily insurance rate or pay for the tool if it is lost in the borehole. This bill can be as high as a million dollars, so it is in the best interest of the oil company to ensure that the tool is in the same condition when it leaves the wellsite as it was when it arrived. Close communication with the MWD crew is essential.

### Arrival of a MWD Tool

Prior to the arrival of the MWD tools, the Wellsite Geologist should review:

- the log/tool requirements (i.e. directional, porosity, etc.)
- depth intervals (kick-off, entire well, etc.)
- the area for storage of the tools
- that all applicable subs and crossovers are shipped with the tools

When the tools are on location, review the paperwork with the service company's representative to verify that all the tools that were requested are present at the wellsite.

### Initial Checkouts and Calibration

Before a MWD tool is attached to the drillstring, it should be checked out to ensure it is in working condition, and all the sensors, valves, generators, etc. are functional. To do this, the tool will have to be moved out of its carrying container and moved to an area close to the service company's logging unit (the cat walk is an ideal location). If it is a collar-based tool, box and pin thread protectors should be on the tool before it is moved.

The hydraulic parameters which will be used during the run should be rechecked to ensure the proper valves, screens, and nozzles are installed in the tool. The MWD crew should ensure that the relevant parameters are “initialized” into the tool and that communication between computer and tool is possible. Sensor calibration or verification of shop calibration can take place at this time.

### Movement of the Tool to the Drill Floor

Any time a MWD tool is moving, there should be constant communication between the MWD crew and the members of the drill crew moving the tool. Again, ensure that the thread protectors are on the box and pin threads before movement begins.

The tools have a standard carrying method, and it is the MWD crew's responsibility to inform the drill crew of that method and ensure that only that method is used. This will prevent damage to the threads and internal components. For collar-based tools, ensure that all subs and crossovers are on the drill floor prior to moving the tool. This will save time during tool make-up. The Wellsite Geologist should check to see that the BHA tally figures are correct before any make-up begins.

### Pre-Drilling Checks of the MWD Tool

During the trip into the hole, the MWD tool can be checked to ensure that pulsing is taking place and the tool is functioning. Each tool has certain set points to tell the MWD tool's processor when to send data to the surface. Typical transmission triggers include:

1. Stop Pumps
2. Wait 15 Seconds
3. Start Pumps

During trip in fill-ups, such pre-test procedures can be followed to see if the MWD tool will pulse data to the surface. These pulse traces can be observed in the MWD logging unit, and parameters such as pulse size, transmission speed, and data type can be monitored.

If the tool appears to have failed, a retest should be conducted. If the tool does not respond to any retests, then the Wellsite Geologist may have to decide whether to trip out and replace the defective tool or to continue to bottom and rely on the tool to record data while drilling, then have the downhole memory “dumped” when the tool is back on the surface.

### Post Drilling Surface Checks

When the MWD tool is back on the surface, it should be observed for any damage which may have occurred during drilling. Areas to check are:

- the resistivity sleeve for wear and tear
- resistivity rings for looseness/cracks
- there are no wires showing
- erosion marks on the metal or outside bolts
- erosion on the float valve or Totco ring
- thread damage or galling
- junk damage

When nuclear tools have been run, a close inspection of the source location (i.e. MWD stabilizer blades) is warranted to ensure that if the tool is rerun the source will not be compromised and possibly lost down hole. Similar radiation safety procedures apply if lithium batteries are used in probe-based MWD tools.

When the tool is still on the rig floor, determination can be made whether to rerun the tool or to lay it down and run another. Considerations include:

- is this the only tool at the wellsite
- are any of the sensors damaged
- has tool stopped pulsing
- is there enough memory available
- is it transmitting, but no memory
- do the pulse sizes indicate significant wear on the pulser, which could mean failure during the next run

The MWD crew must be able to respond to these questions and provide their recommendations as to the ability of the tool to withstand another run. They should also be able to state the tool's MTBF (Mean Time Between Failure), and these hours checked against the time on the present tool. If there are any questions which remain unanswered, and another tool is available and checked-out, it is best to run the newer tool. The old tool can then be laid down and a thorough inspection made of the components. If the tool passes these checks, it can be rerun at another time.

## Shipment of MWD Tools Back to Base

Tools will have to be removed from the wellsite if there is a failure, if the tool is close to failure hours, or if the MWD job is completed. The same carrying procedures should be followed, with box and pin protectors placed on the threads, and the tool secured in it's carrying container. Any special packing requirements are the responsibility of the MWD crew (these should be known and communicated in advance).

## Conclusion of the MWD Service

MWD services can be conducted throughout the entire well, or over certain sections (kick-off points, build sections, etc.). The service can be concluded whenever there are excessive tool failures, or cost over-runs.

All logs, reports, and plots should be received and reviewed as soon as possible. During the review process, the MWD crew should be available to answer questions, provide advice and to explain their recommendations. Points to note are:

- Do the log curves match up with the wireline curves? If not, what are the reasons?
- Does the survey data match up other survey data and is it acceptable for regulatory requirements?

All paperwork should be completed and reviewed by the Wellsite Geologist. Any questions which arise should be answered before any reports or invoices are signed.

A written report concerning the service should be made and forwarded to the oil company. The report should include:

- tool performance
- crew performance
- surface system performance
- effect on drilling operations
- any problems
- recommendations on future use

The report should also high-light the effects of the MWD information on the drilling operations. Was it cost-effective? Did the MWD operations save rig time? Was the MWD crew knowledgeable about their service, the tool, the surface system, and the log output? Did the crew provide recommendations concerning drilling efficiency, formation pressures, and log interpretation? What else did the MWD service provide that proved useful?

## Wireline/MWD Comparison

Some disadvantages of wireline logging systems include: 1) increased rig time costs while wireline operations are underway, 2) wireline logs are run several days to several weeks after drilling resulting in increased filtrate invasion and hole washouts, 3) the logging speeds are very fast, from 1800 to 6000 feet/hour, resulting in poor vertical resolution, and 4) large environmental corrections are required to compensate for 2 and 3.

Wireline logging is expensive, generally running in the $100,000+ range, and the wireline information is post-drilling and therefore cannot be used to assist in the present drilling operations.

MWD logging also has its disadvantages. Compared to wireline logging, it has low data acquisition and transmission rates and few measuring systems (though this is improving). Because of its newness, environmental corrections and interpretation abilities are lagging. Since most of the research and development involves improving the reliability of the tools, log interpretation techniques are still behind wireline techniques. In addition, rig site tool calibration is difficult, causing concern among petrophysicist’s, and there are few test facilities for the instrument subs.

## MWD Transmission or Telemetry Systems

Once the information has been gathered by the downhole sensors, it must be transmitted to the surface. Design and patent considerations have resulted in a few telemetry systems being used at present. The types used in the field today are generally company specific.

### Electromagnetic System

This system allows data transmission through electromagnetic waves, with either the electrical or magnetic component being received at the surface. Electromagnetic transmission allows for two way communication, a high data rate, and transmission when the mud is not circulating (few problems with mud additives exist). In addition there is a low cost of equipment because regular drillpipe can be used with no erosion or wear problems.

Electromagnetic transmission does require a high signal attenuation and a very low signal to noise ratio for the system to be effective. With depth, there will be a need for signal repeaters, and some sort of downhole power generation. Receivers have to be placed over a wide area, and this limits their use offshore.

This system is used by Geoservices.

### Continuous Wave (Mud Siren) System

This system uses a slotted disk, and creates a frequency modulation in the carrier wave. The speed of transmission is between 4000-5000 ft/sec in the drilling fluid.

This type of pulsing system requires no major modification to the rig. The siren system has a higher data rate when compared to the positive and negative pulsers and because of this, more sensors are possible.

The main drawbacks of the mud siren are; the slotted disk is prone to plugging by LCM, there is no transmission with the pumps off, and the system has a low signal to noise ratio.

This system is used by Schlumberger/Anadrill.

### Positive Mud Pulse System

This system causes a periodic, partial restriction of the drilling fluid inside the MWD collar. The speed of transmission is between 4000 - 5000 ft/sec in the drilling fluid. The positive pulse system is relatively low cost and no rig modifications are necessary. It has the added advantage that it is not affected by LCM.

The system does have a slow data rate and is limited to a digital encoding scheme. Other disadvantages include, a low signal to noise ratio, no transmission with the pumps off, and downhole power generation must be increased in order to restrict the mud flow.

This type of system is used by Baker Hughes INTEQ, Smith Datadril, Sperry-Sun and Western Atlas.

### Negative Mud Pulse System

This pulsing system uses periodic venting of drilling fluid from inside MWD collar into the annulus for pulse telemetry. The speed of transmission is between 4000-5000 ft/sec in the drilling fluid.

Negative pulse systems uses less power than positive and siren systems, create sharper pulses for easier detecting/encoding, and can use either time analog or digital encoding schemes.

This system has a relatively slow data rate, the valve can be eroded by the drilling mud, and the pulser valve is susceptible to failure from plugging with to LCM.

This system is used by Halliburton Geodata.

## MWD Sensor Types

MWD has been seen as the replacement for wireline logs, since much of their information is “real-time”. This real-time component however, is based on how far the sensors are behind the bit. MWD tools also have the ability to re-log sections of the borehole during tripping or reaming. These “Measurement After Drilling” or MAD runs are used to verify the readings taken by the first pass (like a wireline repeat run) and have been used to illustrate how much flushing is taking place over a period of time.

Many of the wireline sensors have MWD equivalents. Though they are equivalent, they are not the same.

### Gamma Ray Sensors

The Gamma Ray sensor is usually located nearest the bit. As with wireline logging, it is used as a lithology identifier and a correlation tool. The two types of detectors used are the Geiger-Mueller and the Scintillation Counter. The differences are:

| Geiger Mueller Detector | Scintillation Detector |
|---|---|
| Rugged, Gas Filled Tube | CsI Crystal - Phototube |
| Low Counting Efficiency | Efficient Counter |
| Gross Count-Rate Efficiency normalized for Borehole Size and Mud Density | API Calibrated Before Run |

### Resistivity Measurements

Resistivity sensors also have their MWD counterparts. Many times the resistivity measured by the MWD resistivity devices is considered to be Rt or close to Rt, so there are relatively few conversion or “correction charts”. Most of the corrections are for hole size.

#### Short Normal Device

This was the first MWD resistivity sensor produced. Its design permits good measurements in fresh water muds, when mud and formation resistivity are about the same and borehole effects are minimal. The sensor has good response to formation resistivities between 0.2 and 30 ohm-m.

The Short Normal has correctable vertical response limited to beds thicker than the tool spacing (16 inches). The sensor is calibrated prior to the run, and is borehole corrected for downhole mud resistivity and downhole temperature.

### Focused Current Devices

The focused design permits good resistivity measurements in conductive muds. The device has excellent response to formation resistivities between 0.1 and 1,000 ohm-m. Correctable vertical response is limited to beds greater than 4 inches (100 mm). The sensor is calibrated prior to the run, and is borehole corrected for downhole mud resistivity and downhole temperature.

### Electromagnetic Devices

Electromagnetic resistivity devices are the most common resistivity sensors used with MWD tools. Their design permits good measurements in very fresh and oil-based muds. They have very good response to formation resistivities between 0.2 and 50 ohm-m, and have a correctable vertical response limited to beds greater than 6 inches (150 mm).

Both amplitude (amplitude ratio) and phase (phase difference) measurements are possible, therefore two response curves are recorded and plotted. When combined with focused current devices, the MWD resistivities can handle all mud and formation conditions.

The sensor can be calibrated prior to the run, and borehole corrections are made for downhole mud resistivity and temperature.

## Porosity Measurements

Porosity devices have made MWD tools equivalent to wireline logging in many respects. These are the newest tools available, with research and development continuing on source efficiency, source retrievability, and interpretation methods.

| Neutron | Density |
|---|---|
| Dual detector, compensated system | Dual detector, compensated system |
| Epithermal neutrons detected | Scintillation detectors |
| Excellent clay response | API calibrated porosity |
| API calibrated porosity | |

## Special Hydraulic Considerations

MWD tools operate over a wide range of conditions and drilling fluid types. However, due to the complexity of the internal components, some considerations must be made to ensure those components continue to function and are not destroyed. Several precautions include:

### Sand Content

The sand content should be kept at an absolute minimum, preferably below 1%. Significant amounts of abrasive sand can erode pulser components resulting in the loss of telemetry.

### Lost Circulation Material

LCM can be used if pumped slowly and should never be slugged. Large amounts, pumped rapidly, can plug up a pulser. If pulser fails, however, it should not affect downhole memory.

### Oil-Based Muds

Oil-based mud systems attenuate the pulse size at the surface much more than water based muds. Some software corrections need to be made by the operators.

### Mud Turbines

Turbines have a very high pressure drop which pulsers have to work against. Turbines are more prone to high frequency pump pressure noise, which can cause distortion of the surface signal.

### Positive Displacement Motors

These motors will also produce a high frequency pump pressure noise depending on the type of motor. MWD tools are usually placed above PDM's, which means they have to work against the pressure drop of the motor and the drop at the bit.

## Checklist for MWD Services

The checklist below summarizes this chapter and; 1) lists the questions that should be asked by the Wellsite Geologist, 2) procedures to be followed, 3) output required during MWD logging runs, and 4) post drilling requirements.

### Pre-Drilling Program - Primary Use of MWD Services

- Requirements for Better Bed Resolution
- Determination of Coring Points
- Pore Pressure Evaluation
- Real-Time Formation Evaluation
- Downhole Drilling Parameters
- Directional Control

### Initial Contact By Wellsite Geologist

- Review Program, Expected Lithologies, Drilling Conditions
- Check if Back-Up Tools are Required
- Check if all Accessories (XO's, batteries, etc.) are on Location
- Check Surface Equipment
- Check Tool/Shop Calibrations
- What type of pulse system is being used?
- Is output to mud loggers required?
- Are surveys required on every connection?
- What happens if tool fails?

### Morning Report Requirements

- One Copy: 1-inch = 100 ft (m) of logged interval
- One Copy: 1-inch = 500 ft (m) of logged interval
- One Copy: Summary of Survey Data and TVD
- One Copy: Summary of Pore Pressure Interpretation
- *Any special requirements from oil company*

### Tripping-In

- Sensors, Valves and Generators/Turbines working
- Valves, Screens and Nozzles matched to hydraulic parameters
- What is the transmission trigger - Observe
- What is the pulse size - Observe
- What is the transmission speed - Observe
- What is the data sequence - Observe
- What is the Sand Content in the drilling fluid - Observe Test

### While Drilling

- Do curves show a “wireline” appearance?
- Is the appearance of the pulse consistent?
- Confirm pore pressure interpretations
- Is the driller waiting for the signal before resuming drilling
- Is the depth (pipe tally, mud loggers, MWD) consistent

### Post-Drilling

- Is all log header information correct?
- Are the field prints labeled correctly?
- Note tool response vs wireline response
- Note hole invasion from MWD vs wireline
- Note any downtime, tool problems, and tool condition
- Does memory download correctly?
- When will final log prints be available?

Chapter **10**

# Drill Stem Testing

A drill stem test (DST) is a temporary completion whereby the desired section of the open hole is isolated, and relieved of the mud column pressure through the drill pipe (drillstem).

The decision to run a drill stem test on a zone is often based on shows of oil in the cuttings which, in the opinion of the geologist or engineer, deserve detailed investigation. This may happen many times in the course of drilling a well, with as many as 20 or 30 tests being conducted on a single well. Although the cost of such detailed testing is quite high, it is much better to test for a productive zone rather than miss the zone entirely.

## General Considerations

Proper planning and consideration of the factors involved are essential to successful testing. The following points are of particular importance.

1. **Condition of the hole**: The close tolerance between the hole and the tool assembly requires a full gauge, clean, well bore if the tool is to reach bottom in an undamaged, unplugged condition. Wall cake and cavings shoved ahead of the packer may plug the perforations and choke valve when the tool is opened. It is common practice to circulate for some time prior to testing, so that all cuttings are removed from the hole.

2. **Pressure surges**: The drill stem test conditions represent a severe case of pressure surge, because the lower end of the pipe is closed, necessitating displacement of the total drill pipe volume. Special consideration should be given to pipe running and pulling speeds to avoid undue pressure surges.

3. **Operating conditions**:

   *Length of section*: The length and location of the test section governs the amount of tail pipe required and the choice of a conventional or straddle test. The testing of short sections are more conclusive, and are generally preferable. Also, the volume of drilling fluid below the packer should not fill the pipe to such an extent that its back pressure interferes with the test.

   *Packer seat*: The packer seat location (while of no particular importance for tests run inside casing), is critical for a successful open hole test (Figure 10-1). The test should be performed in a true gauge hole, where the packer is opposite a dense, consolidated formation. Limestones, dolomites, anhydrites, or hard dense shales are all satisfactory.

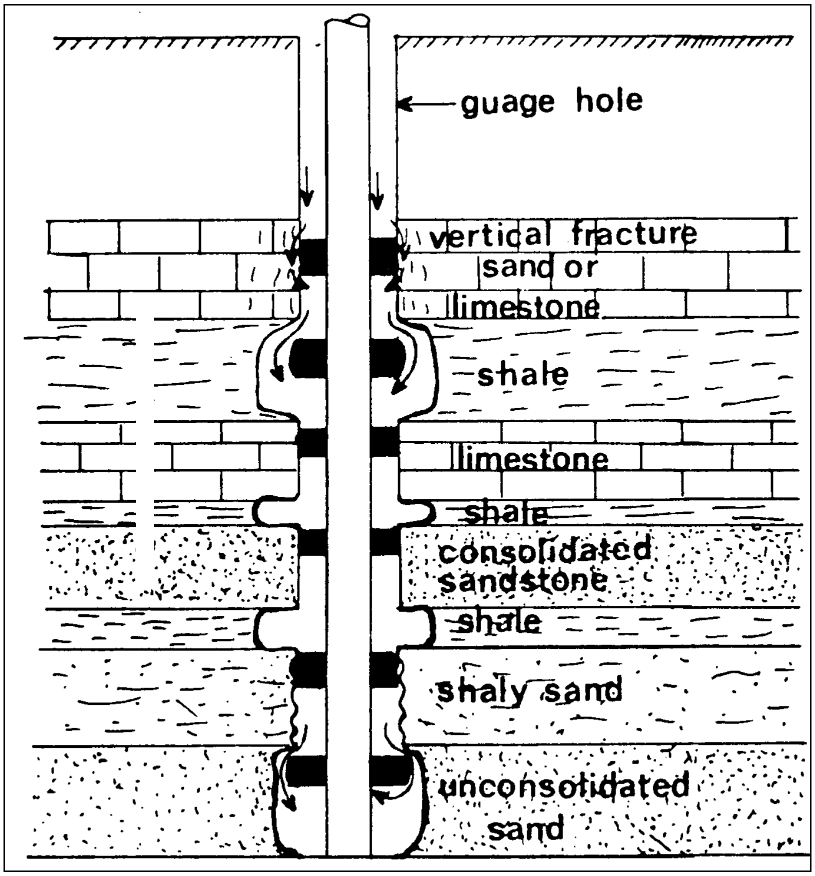



**Figure 10-1: Selection of Packer Seats For a DST**

*Choke sizes*: The size of the bottom hole and surface orifices depends on the anticipated test conditions. The bottom choke is of prime importance and is used to govern the flow rate. The top choke is used primarily as a safety measure and should be considerably larger than the bottom choke, to minimize surface pressure in case a flowing test is obtained. The producing pressure drop around the borehole depends on the flow rate, which in turn is governed by the bottom choke size.

*Use of cushions*: This refers to the practice of placing a certain length or volume of liquid inside the drill pipe, rather than run it dry (Figure 10-2). This is commonly done by two reasons: first, to reduce the collapse (external) pressure on the drillpipe in deep holes, and second to reduce the pressure drop on the formation across the packer when the tool is first opened.

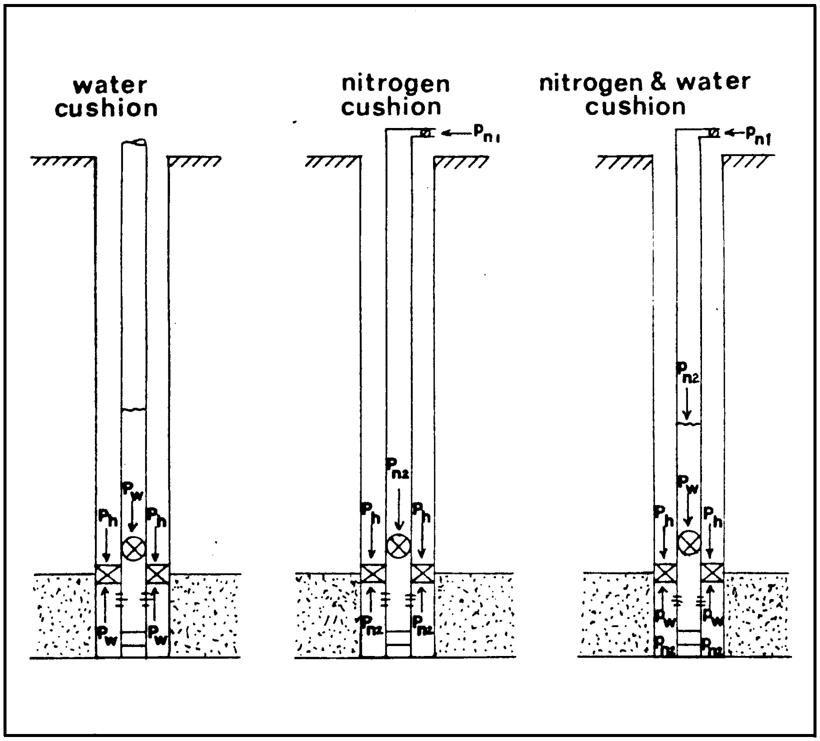



**Figure 10-2: Using a Cushion During a Test**

*Length of test*: This is difficult, if not impossible, to predict until after the test has commenced and some observations are available. In hard rock areas where the pipe is not in too great a danger of sticking, the flow test is often several hours long. If the fluid has not reached the surface within this period of time, it is usually desirable to leave the tool open, as long as appreciable entry into the pipe is taking place. The shut-in period after the flow test should be long enough to establish a stabilized static pressure.

## Types of DST Tools

The basic test tool assembly (Figure 10-3) consists of:

- A rubber packing element or packer which can be expanded against the hole to isolate the annular sections above and below the element.

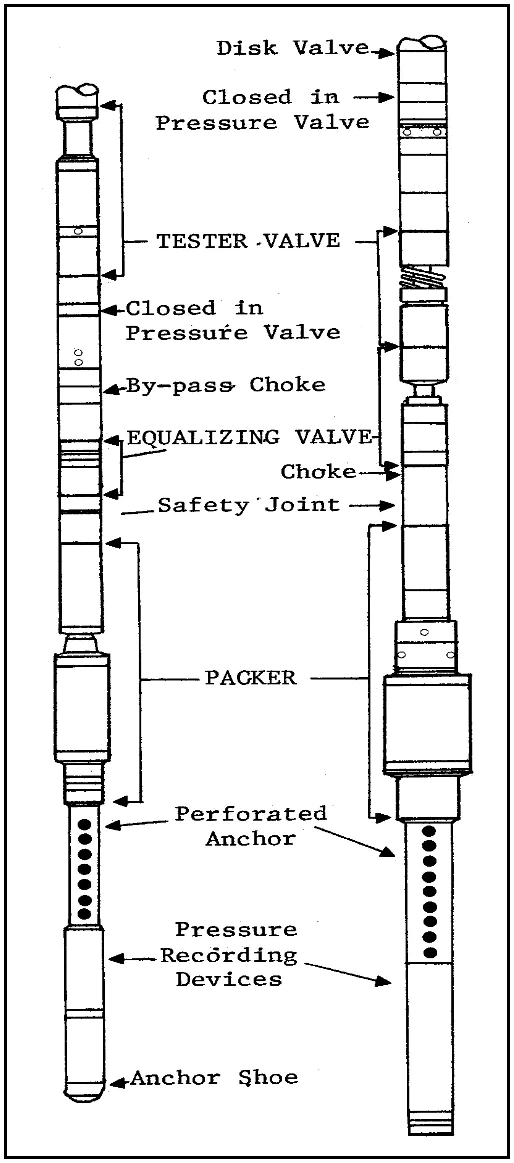



**Figure 10-3: Typical DST tools**

- A tester valve to control flow into the drill pipe. This is to exclude mud during entry into the hole and to allow formation fluids to enter the hole during the test. The valve will by-pass fluid to allow pressure equalization across the packer after completion of the flow test.

The drill stem test tools are of the following types:

- The most common, and safest, type of tool is the conventional bottom-hole test. This is where the packer is set some distance up hole and the test zone is located at, or near, the bottom of the hole.
- The straddle packer test is necessary when isolation from formations both above and below the test zone is necessary. Straddle testing is less desirable than conventional testing, from both a cost and an operational hazard standpoint. Two packers are more likely to become stuck than one, since any formation material which sloughs or caves from the test interval may accumulate between the packers.
- Zones behind casing may be tested through perforations by the same basic procedures except that the packer used has slips which engage or grab the casing wall. These are commonly called hook-wall assemblies. Testing inside casing is widely used in soft rock areas where open hole testing is particularly hazardous.

## Procedures Prior to Testing

Before running a test, the borehole and drilling fluid must be in good condition. Several circulations are required to clean the hole of cuttings and to ensure the mud properties are correct. The mud density should be continuously checked in order to determine the correct hydrostatic pressure, so it can be checked against the DST's pressure recorder.

## Performing a Test

The procedures and packer configuration for running a DST can be seen on (Figure 10-4). The operation is as follows:

1. When the tool is run into the hole, the packer is collapsed to allow the displaced mud to flow around the tool. As the tool is lowered, the pressure recorder indicates the increasing hydrostatic pressure.
2. After the tool has reached bottom, the packer is set (compressed and expanded) by slacking off the weight of the drillstring, which is then transferred to the anchor pipe, below the packers. Setting the packer isolates the lower zone from the rest of the borehole.
3. A further slack-off of drillstring weight opens the tester valve, and the isolated section is exposed to the low pressure inside the drillpipe. Formation fluids from the test interval will enter through the ports of the test tool and rise into the drillpipe. The rate and height at which the fluid rises will depends on the effective productivity and pressure of the formation, and the weight of the cushion (mud, water or nitrogen). The formation

fluid produced will reach the surface and continue to flow if conditions are favorable.

4. At the surface, the first thing noticed is a “blow of air” from the open end of the surface system. The strength of the blow is a measurement of the rate of fluid rising in the pipe. If the fluid continues to rise, this blow will be followed by flows of drilling fluids (or cushion), gas-cut mud, gas, water, and/or oil. If the formation pressure is not great enough to lift the reservoir fluids to the surface, a pressure equilibrium will be obtained within the drillpipe, and all flow will cease.

5. At the end of the test, the tester valve is closed to trap any fluid above it. The bypass valve is then opened to equalize the pressure across the packer.

Much information can be gained during this shut-in period, especially if the shut-in time is sufficient to allow the pressure in the borehole to approach the static reservoir pressure. This information is the basis of the Horner Plot analysis.

6. The setting weight is taken off, and the packer is pulled free. The drillstring is removed from the hole and broken off. If there is any fluid inside the drillstring, the fluid can be examined. The number of stands of fluid is recorded, and converted into barrels as a basis for estimating the formation productivity.

Because of time considerations, sometimes such stand-by-stand sampling is not performed and circulation is reversed. This reverse circulation is performed by closing the BOP’s and pumping mud down the annulus. The mud enters the drill pipe through reversing ports, thereby displacing fluids in the drill pipe.

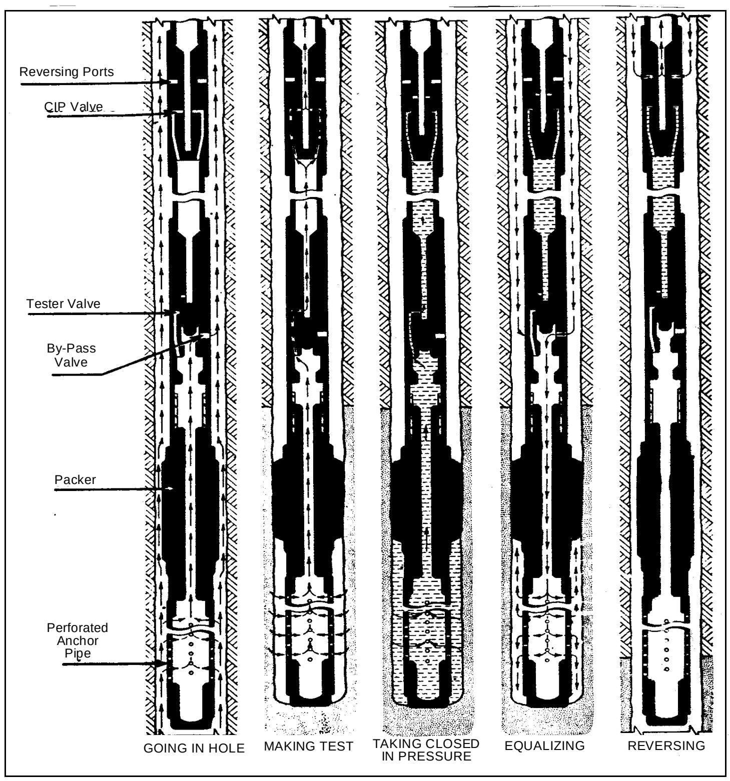



**Figure 10-4: A Typical Bottom-Hole Drillstem Test**

## Insuring an Effective Test

To obtain a successful test, it is necessary that the packer, or packers seal effectively, that all equipment functions properly, and that the test procedures are planned and carried out so that stabilized conditions are obtained in each portion of the test cycle.

Certain rules have been proposed for the various test operations. Which rules can be used to assist in the planning stage?

1. The initial shut-in period should be at least 60 minutes in length. Based on a series of tests only 50% of the wells reached maximum static pressure within 30 minutes, 75% in 45 minutes, and 92% in 60 minutes. The remaining 8% were in tight formations, and were non-commercial.

2. One to two hours of a “good to strong blow” will usually yield satisfactory drawdown data; otherwise, when the blow dies, the tool can be shut-in for build-up.

3. Shut-in time should never be less than 30 minutes. For a well with a good flow to the surface, it should be at least one half the flowing time. For an average well blow, it should be equal to the

flowing time, and for a well with poor flow characteristics, it should be at least twice the flowing time.

## Surface Equipment

The surface equipment is designed to carry produced formation fluids to a suitable storage, or disposal area. This assembly will usually be equipped with a control choke to restrict the rate of flow and protect the system from high pressures (Figure 10-5). Flow rate metering equipment will also be included.

Therefore, the test records should include a description of fluid production as a function of time.

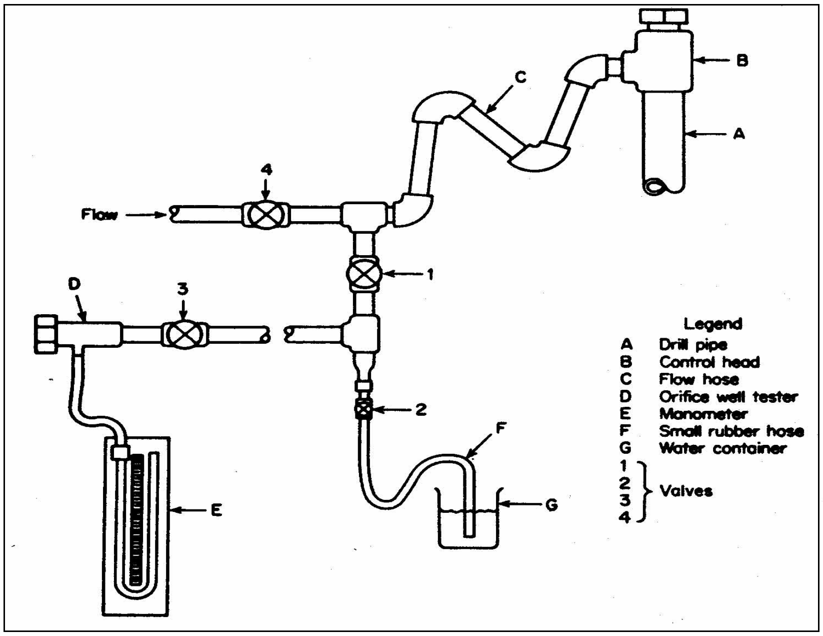



**Figure 10-5: Schematic Arrangement of Surface Equipment**

When the tool is opened, the entry of fluid into the pipe displaces air so that a “blow” is obtained through the hose, F (valves 1,2 open; valves 3,4 closed). If the blow is excessive, valves 3 or 4 may be opened. If the fluid surfaces, it is diverted through valve 4. If gas surfaces, the gas is metered through value D.

For example, a gas flow may be described as “weak”, “medium”, or “strong” blow of gas - lasting 15 minutes. Flow rates may be reported as “oil flow of 25 bbls/hr through 5/16-inch choke.”

It is necessary that quality data be obtained to serve as basis for test interpretation.

## Surface Blow Interpretation

There are some general statements that can be made regarding the interpretation of surface blow on DST's. (Figure 10-6)

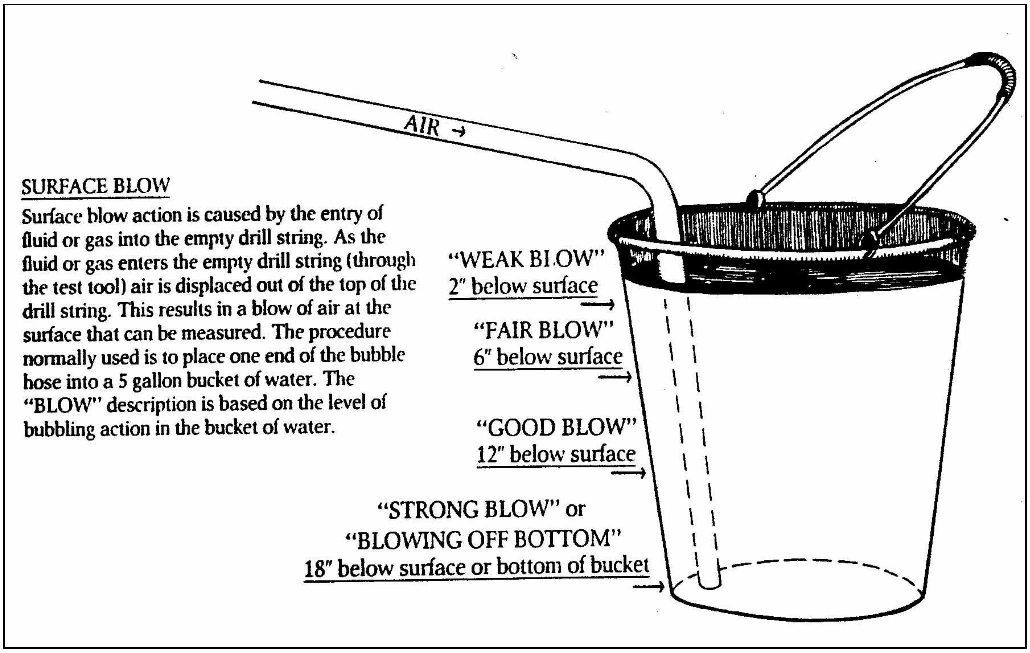



**Figure 10-6: Surface Blow Interpretation**

1. Weak blow at the surface indicates slow entry of fluids into the drill string. This can be caused by several factors as:
   - tight zone - low permeability
   - plunged anchor or tool
   - highly damaged test zone
   - low pressure test zone
2. A strong blow at the surface usually indicates that there is rapid entry into the drill stem. This indicates:
   - good permeability
   - good formation pressure

## DST Data

The data from a drillstem test consists of all the qualitative, quantitative, and procedural information recorded at the surface and the pressure charts retrieved from the bottom-hole test assembly. All of these data sets are necessary for complete and proper interpretation of the test results.

A qualitative inspection of the pressure chart (Figure 10-7) should be made to ensure that the sequence of events is understood and that no irregularities or tool failures occurred.

The pressures listed below should be taken from the chart and recorded. They are computed by measuring the deflection above the base line and obtaining a corresponding pressure from a calibration curve for the recorder used.

Current instruments are reportedly accurate to 1% and can detect changes of 0.5 psi. Various chart magnification techniques are used to obtain more accurate chart deflections. These pressures include:

1. Initial Hydrostatic Pressure (IHP), exerted by the mud column
2. Initial Shut-In Pressure (ISIP)
3. Initial Flow Pressure (IFP), the lowest pressure recorded just after the tool is opened
4. Final Flow Pressure (FFP), The pressure just before the tool is closed
5. Final Shut-In Pressure (FSIP)
6. Final Hydrostatic Pressure (FHP)

In planning and conducting a drillstem test, it is important to remember that each test is as individualistic as the formation being tested. Specific, local experience is the only means by which a complex series of test procedures can be designed with any real degree of confidence.

Figure 10-7, is an example of a typical, but idealized, drillstem test pressure chart for a test with one flow and one final build-up. This chart is a mechanical record of pressure versus time.

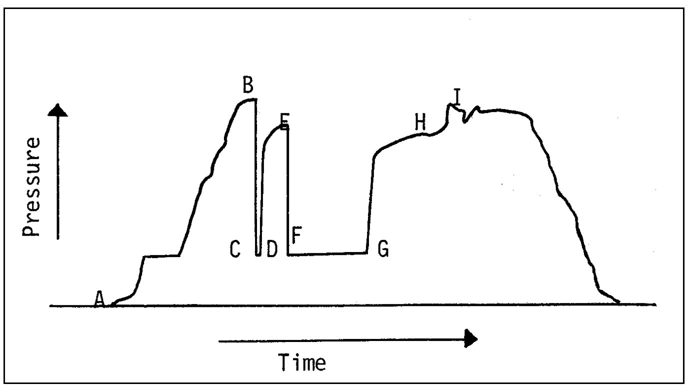



**Figure 10-7: Typical DST Chart**

- AB - Increasing Hydrostatic Pressure as tool is run to depth
- B - Initial Hydrostatic Pressure

- BC - After Packers are set, tool is opened
- CD - Initial Flow Period
- DE - Initial Shut-In Pressure
- EF - Tool is opened a second time
- FG - Final Flow Pressure Curve
- HI - Mud column is allowed into test interval and packers are unseated
- I - Final Hydrostatic Pressure

## Drillstem Test Analysis

Advances in the technology within the petroleum industry have introduced methods (the Horner Method is one) by which engineers and geologists can take DST data and use it as a tool in formation evaluation.

The data obtained from a DST includes a physical description of reservoir fluids, a volume of recovered fluids, flow times, shut-in, and a bottom hole pressure-time chart showing the well bore pressure measurements during the various tool manipulations.

Reservoir characteristics that can be calculated from this DST data are:

1. Permeability - The average effective permeability of the formation to the actual fluid produced.
2. Well Bore Damage - Whether or not the bore hole has been damaged by the drilling action.
3. Reservoir Pressure - Determination of the static reservoir pressure.
4. Depletion - Determination of the total area of the reservoir for production purposes.
5. Radius of Investigation - Determination of the effect that the removal of fluids has on the formation.
6. Barrier Indications - If some type of barrier or anomaly (a fluid contact) exists within a formation.

## The Horner Method

The Horner investigation on fluid flow during a drillstem test is based on the premise that when flow is shut-in and the formation pressure is allowed to build-up, the well bore acts as if it is the same as the reservoir. As a result, any pressure recorded in the well bore, during build up, is the same as the pressure recorded at any point in the reservoir.

The Horner method is the most accepted type of pressure build-up analysis used today. Horner, along with other build-up methods, is based on how a formation recuperates (shut-in) from taking a known volume of fluid from it (flow period) (Figure 10-8).

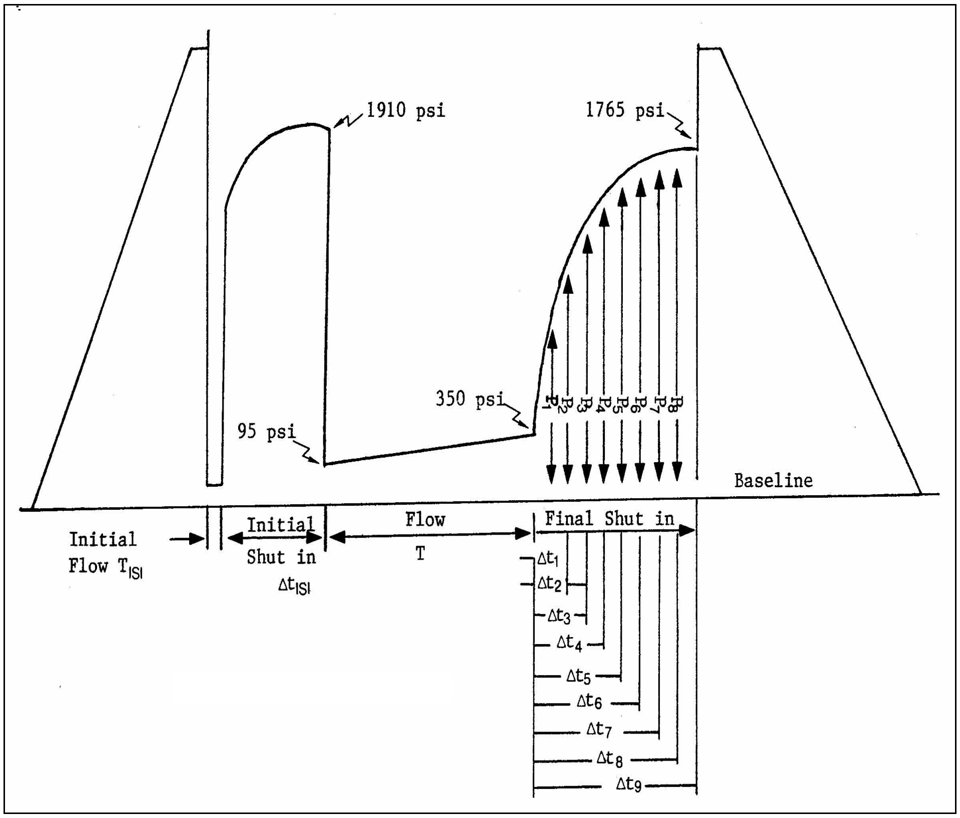



**Figure 10-8: Pressure vs. Time Breakdowns**

The ability of a formation to give up fluid is proportional to its ability to recuperate from the loss of fluid. Most formations given long enough shut-in time, go through three phases of build-up:

1. After flow
2. Horner straight line
3. Pressure stabilization

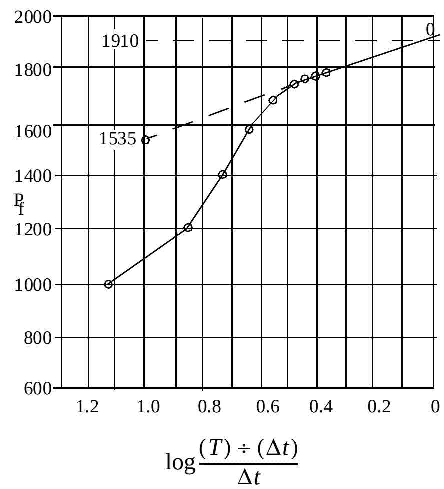
The Horner method also makes the following assumptions:

- Single phase flow
- Homogeneous matrix
- Radial flow
- Infinite reservoir
- Constant flow rate

Any variations from these assumptions will be considered an anomaly. The Horner plot is a relationship of shut-in pressure vs. the log (T + Δt/Δt). The Horner straight line slope is the change in pressure over one log cycle (T=flow time, t=time into shut-in). As “T” approaches infinity, T +Δ t/Δt approaches 1, and the log approaches 0. From this we extrapolate a maximum reservoir pressure.

| (1) Point | (2) Shut-In Time, Δt | (3) Pressure $P_f$ | (4) | (5) |
|---|---|---|---|---|
| 1 | 5 | 965 | $\frac{65+5}{5} = 14.000$ | 1.146 |
| 2 | 10 | 1215 | $\frac{65+10}{10} = 7.500$ | 0.875 |
| 3 | 15 | 1405 | $\frac{65+15}{15} = 5.333$ | 0.727 |
| 4 | 20 | 1590 | $\frac{65+20}{20} = 4.250$ | 0.628 |
| 5 | 25 | 1685 | $\frac{65+25}{25} = 3.600$ | 0.556 |
| 6 | 30 | 1725 | $\frac{65+30}{30} = 3.167$ | 0.500 |
| 7 | 35 | 1740 | $\frac{65+35}{35} = 2.857$ | 0.455 |
| 8 | 40 | 1753 | $\frac{65+40}{40} = 2.625$ | 0.419 |
| 9 | 45 | 1765 | $\frac{65+45}{45} = 2.444$ | 0.388 |

**Table of Pressure Breakdowns**




**Plot of Pressure Breakdowns**

In this example, maximum reservoir pressure is mechanically measured by the initial shut-in pressure, or 1910 psi. The final shut-in pressure has been identified by point 9 as being in “steady state”, so it can be as Pf’ or 1765 psi, at a shut-in time (Δt) of 45 minutes.

So by definition:

$$M = \frac{Po - Pf'}{\log\left(\frac{T + \Delta t}{\Delta t}\right)} = \frac{1910 - 1765}{\log\left(\frac{65 + 45}{45}\right)} = \frac{145}{0.338} = 374 psi/\log cycle$$

Since a plot has been made, “M” can be solved using the graph or:

M =Point a - Point b = 1910 - 1535

M= 375 psi/log cycle

In this work on pressure build up, Horner used all information available to formulate an equation to solve for the above reservoir characteristics. In oilfield units, Horner's equation reads:

$$Pf' = Po - \frac{162.6QuB}{kh} \times \log\frac{T+\Delta t}{\Delta t}$$

Where:

| | |
|---|---|
| Pf' | = formation pressure during build up (psi) |
| Po | = maximum formation pressure at T (psi) |
| T | = time of flow (minutes) |
| $\Delta$t | =time of shut-in (minutes) |
| Q | = rate of flow (bbls/day) |
| u | = fluid viscosity (cps) |
| B | = formation volume factor (vol/stock tank) |
| h | = formation thickness (feet) |
| k | = formation permeability (millidarcies) |

From available information, most of these unknowns can be solved. For example "Q" is the recovered fluid volume during T, "u" and "B" are determined from tables if the oil gravity and gas/oil ratio is known, "h" from electric logs, and "Po" can be measured by the leveled out initial shut-in build up. This leaves only permeability (k) as an unknown.

Given the basic assumption of the Horner Method, steady state, single phase flow conditions, and a homogeneous formation, several of the above terms will remain constant. They are Q, u, B, k, and h. Horner then derived the constant "M" by:

$$M = \frac{162.6QuB}{kh}$$

and by finishing the equation:

$$M = \frac{Po - Pf'}{\log\left(\frac{T+\Delta t}{\Delta t}\right)} = \frac{162.6QuB}{kh}$$

This constant "M" is representative of a given fluid having physical properties uB flowing through a formation having physical properties kh at a rate Q. Each rate Q will have its own constant for that particular formation.

Chapter 11

# Interpretation of Formation Test Results

The procedures for running a wireline formation test and Pretest operations (Figure 11-1) are described in the "*Advanced Wireline/MWD Procedures*" manual. Besides knowiht the procedures, the observation, quality control, and review of test data is a vital part of the Wellsite Geologist's responsibility whenever these tests are performed.

## The Pretest

An important reason for conducting Pretest's is to ensure the collection of a good sample by pretesting the formation for a good hydraulic seal and to make sure it had sufficient permeability. Pretesting is accomplished by monitoring pressures when small "test" samples of fluid are drawn from the formation. With an accuracy of ± 30 psi and a resolution of ± 1 psi (for a 10,000 psi pressure gauge), pretesting is an important test in its own right.

As mentioned above, one piece of information that can be gained from a Pretest is an estimate of the formation's permeability. This is done by monitoring the formation pressure "drawn-down" caused by the Pretest. However, it should be remembered that this draw-down measurement has a shallow depth of investigation and the permeability calculated will only be indicative of the permeability within a few inches of the borehole.

Figure 11-2 is an expanded portion of the RFT pressure recording. With the pressure track scaled from 0 to 10,000 psi and the test times measured in seconds, both pretest chambers contain a set volume (i.e. 10 cc).

To determine the amount of formation pressure that is drawn down ($\Delta P$), the values read from the recording are subtracted from the formation pressure. For example:

| | |
|---|---|
| Formation Pressure: | 5775 psi |
| First Pretest: | 2350 psi |
| Second Pretest: | 1100 psi |

$$\Delta P_1 = 5775 - 2350 = 3425 \text{ psi}$$

$$\Delta P_2 = 5775 - 1100 = 4675 \text{ psi}$$

The flow rates are measured directly from the pretest recording, using the test times. For example:

| | |
|---|---|
| First Pretest: | 15.5 seconds |
| Second Pretest: | 7.5 seconds |

$q_1 = 10 \text{ cc} \div 15.5 \text{ sec} = 0.645 \text{ cc/sec}$

$q_2 = 10 \text{ cc} \div 7.5 \text{ sec} = 1.333 \text{ cc/sec}$

The model most commonly used in RFT testing to determine permeability is the" steady-state quasi-hemispherical flow", using:

$$k = \frac{C \times \mu \times q}{2\pi \times r_p \times \Delta P}$$

where:

| | |
|---|---|
| $k$ | = draw-down permeability (md) |
| $q$ | = flow rate (cc/sec) |
| $\mu$ | = viscosity of flowing fluid (cp) |
| $\Delta P$ | = draw-down pressure (psi) |
| $r_p$ | = radius of sampling orifice (in) |
| $C$ | = flow shape factor (1.00 for hemispherical flow, 0.50 for spherical flow, 0.75 for flow into probe set in an 8-inch borehole) |

The fluid withdrawn from the formation during the Pretest is usually filtrate, so the viscosity can be determined (corrected for formation temperature). Also, if the borehole is larger than 8-inches, C will decrease (i.e. the flow becomes more spherical). Because both C and $r_p$ are based hole size (the larger the hole size, the larger the RFT tool and hence the larger the orifice), the term $C/2\pi r_p$ can be evaluated separately. When this is done and the equation converted into oilfield units, the equation becomes:

$$k = Z \times \frac{q \times \mu}{\Delta P}$$

where:

| | |
|---|---|
| $Z$ | = 5560 when a "standard" RFT is used |
| | = 2395 when a large-diameter or "fast-acting" probe is used |
| | = 1107 when a large-area packer is used |

Therefore, if a standard RFT tool is used in a water-based mud (having a filtrate viscosity of 0.5), then:

$$k_1 = 5660 \text{ x } \frac{0.645 \text{ x } 0.5}{3425} = 0.53 \text{ md}$$

$$k_2 = 5660 \text{ x } \frac{1.333 \text{ x } 0.5}{4675} = 0.80 \text{ md}$$

It is often observed that the permeability calculated from the second pretest is higher than the first. This is usually due to the cleaning of the formation during the test.

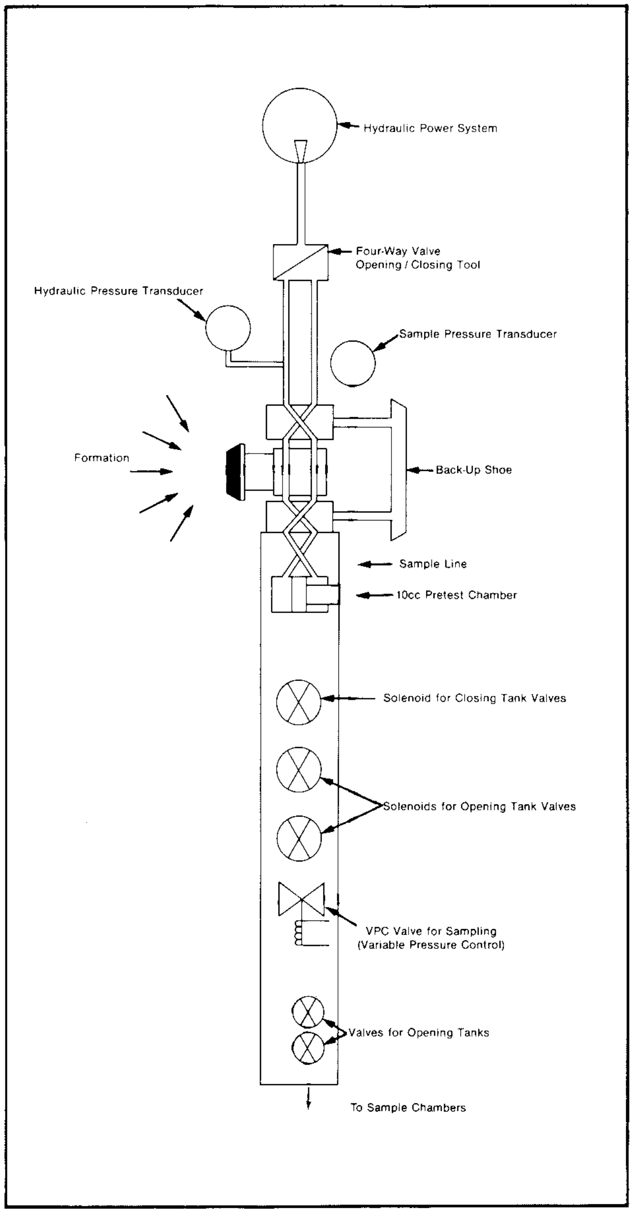



**Figure 11-1: Schematic Diagram of a Formation Test Tool**

## Fluid Recovery

The Wellsite Geologist will be responsible for the safe and proper testing of the fluids recovered during formation testing. Since the fluids recovered will be oil, gas or water and more often than not, all three in some sort of combination, this makes the collection and dispatch even more important.

When the tool is returned to the surface, it will be suspended in the rotary table and clamped in place. A small Christmas tree will be screwed into the sample chamber's drain connection and a flexible hose connected to the sampling manifold, gas/liquid separator and a gas meter.

1. When the Christmas tree valves are opened, the opening pressure should be recorded, along with the temperature. Higher pressures indicates gas recovery. Lower opening pressures usually indicates mud filtrate recovery, and extremely low opening pressures indicates that the chambers are full of filtrate or empty (because of a failure). If a failure has occurred, the cause should be pin-pointed as soon as possible.
2. When a sufficient gas sample has been collected, all remaining gas is bled through the gas meter.
3. When the chamber pressures are atmospheric, all valves should be closed and the gas sampling manifold removed from the system. The Christmas tree is replaced by a hose adaptor connected directly to the gas/liquid separator.
4. The sample chamber valve is opened again and all remaining liquids and solids are recovered by displacing the floating piston upwards. The tool must remain vertical during this operation.
5. The final reading of the gas meter is recorded and the contents of the separator bottle removed and taken to the wellsite laboratory/ mud logging unit for examination and evaluation.

### Gas Recovery

The gaseous hydrocarbons can appear in solution (in water or oil) or as free gas. As mentioned above, the separator will have some sort of gas meter attached to it to determine the gas volume collected under “standard” conditions. An accurate gas volume measurement at the opening pressure and atmospheric conditions are required to calculate the gas/oil ratio (GOR).

## Water Recovery

Water collected from the formation test can be filtrate, formation water, or a mixture of both (usually a mixture). Determination of the amount of interstitial or formation fluid in the mixture is an important parameter in formation evaluation, and is easily calculated.

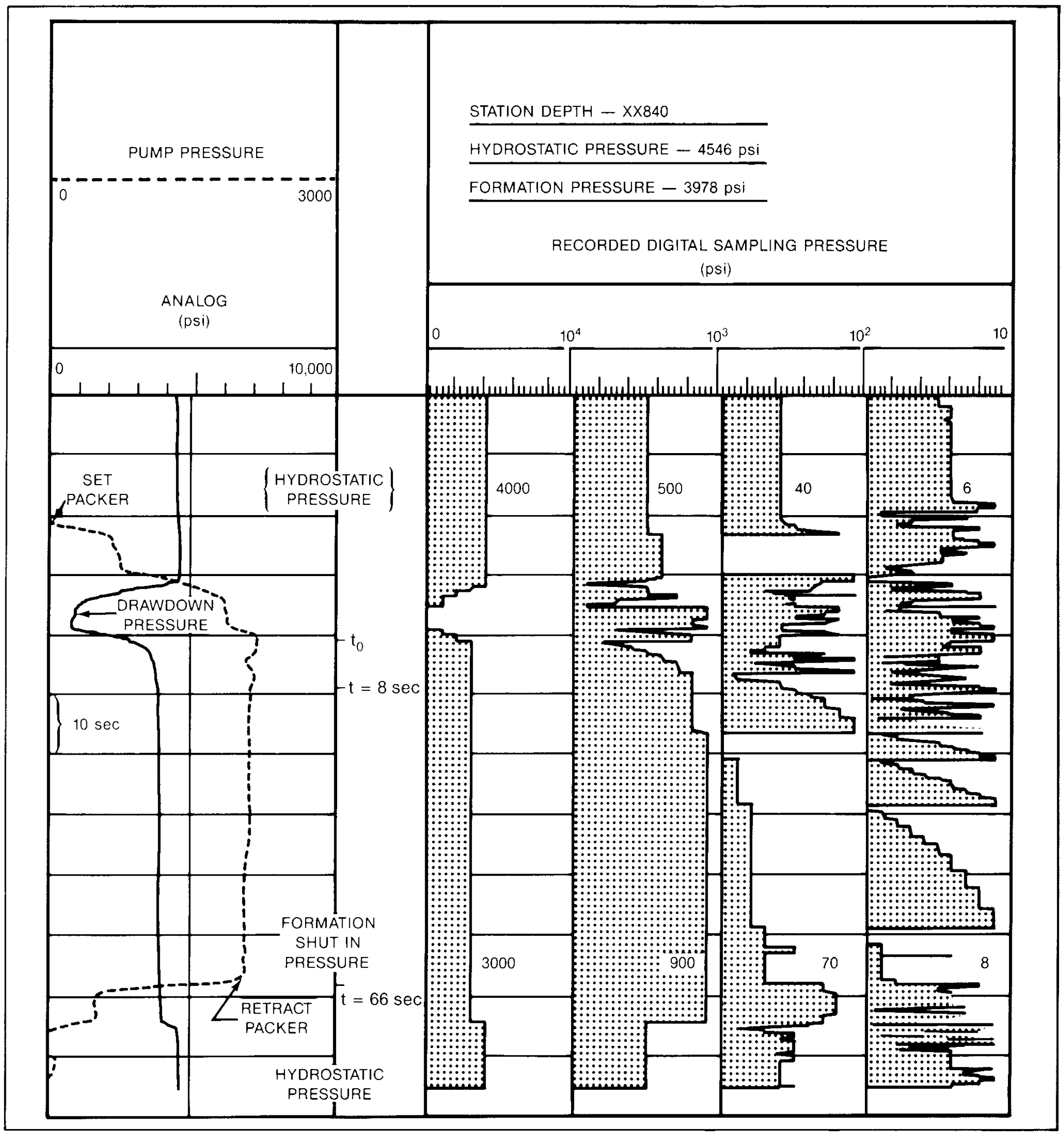



**Figure 11-2: Example of pretest pressure recording**

Using wireline logging results and by the service company's resistivity-salinity charts, we can determine:

- $R_{mf}$ = mud filtrate resistivity (Ω-m)
- $P_{mf}$ = mud filtrate salinity (ppm)
- $R_w$ = formation water resistivity (Ω-m)
- $P_w$ = formation water salinity (ppm)

Using a standard resistivity probe, we can measure the resistivity of the test fluid ($R_{tf}$) and then determine it's salinity ($P_{tf}$). Remember that all the resistivities must be at the same temperature (this can be done at surface temperature or formation temperature). Then the percentage of formation fluid ($\%_{ff}$) in the test sample can be calculated, using:

$$\%_{ff} = \frac{P_{tf} - P_{mf}}{P_w - P_{mf}} \times 100$$

- When two samples are taken from the tool, if the $\%_{ff}$ increases, it can indicate that one formation may produce a higher proportion of water.
- If $P_{mf} > P_{tf}$ , it can indicate that either the filtrate recovered is from a different mud system than the one used when the test was taken, or the formation water is less saline (fresher) than the mud filtrate.
- If the $\%_{ff}$ is small (≈ 30%), the formation will probably produce only hydrocarbons. It would then be advisable to determine the amount of hydrocarbons (gas and oil) that was recovered with the test water.

## Oil Recovery

The amount of oil recovered is generally very small. This is due to the flushing process while drilling. If the volume of oil is large enough, the specific gravity (S.G.) can be measure using a hydrometer and the Gas/Oil Ratio (GOR) can be calculated using:

$$\text{GOR} = \frac{\text{cubic feet of gas}}{\text{cubic centimeters of oil}} \times 159{,}000$$

When two oil samples are recovered, especially if the oil contains a significant amount of gas, one of the chambers should be sent to the laboratory for a PVT (Pressure, Volume, Temperature) analysis. The “bubble point” can then be determined.

## Quality Control Procedures

Proper quality control methods are important prior to, during, and after the formation test in order to ensure accurate interpretation of the data. Standard quality control methods include:

1. **Critically checking the test/sampling conditions**

   When the decision has been made to test, a review of the wireline logs (5-inch scale) is necessary. Carefully review the DIL/Sonic/GR and the FDC/CNL/GR/CAL, paying particular attention to the test points. Remember, the test points should always be the most porous intervals.

   The two most important aspects with regards to formation testing are; 1) the condition of the borehole and 2) the condition of the formations to be tested. Keeping track of the drilling fluid parameters and rechecking the caliper across the test formation will eliminate many of the problems associated with formation testing. When the testing company arrives on location, inform the test engineer of the hole conditions and the hydrostatic/pore pressure values.

   Two maximum thermometers must always be run with formation tests, and must be read after each run into the borehole.

2. **Keep administration of all data separate from the service company's records**

   When the test program is announced, the Wellsite Geologist should ensure that the correct forms are on location. For an FIT, the standard FIT form. For an RFT, the standard RFT form. These forms are to be filled out by the Wellsite Geologist. Though it is wise to consult with the test engineer, especially when determining whether or not the tool is operating satisfactory, all information entered on the forms is the responsibility of the Wellsite Geologist.

3. **Witness all operations involving pressure gauges and check the marking of charts**

   Pressures, both analog and digital, are to be recorded by the test company on the standard log format. The normal time scale is equivalent to twenty feet per minute. The paper speed should be five times normal during setting, pretest and the early part of the build-up. Normal paper speed can be used during the rest of the test. The time scales used should be indicated on the log.

The hydrostatic pressure must be recorded for at least a half-minute before and after each setting of the tool, and the tool should not be set until the hydrostatic pressure has stabilized.

After the tool is set, the pretest will begin automatically. It usually takes 15 to 20 seconds to fill the two 10 cc pretest chambers, after which the build-up starts. The pretest is completed when the final build-up is constant for at least two minutes.

4. **Witness all sample taking/recovery operations**

If the build-up has not started three minutes after setting the tool, retract the pad and move the tool one foot upwards and try again. If this second try does not yield a formation pressure, go to the next depth, unless otherwise specified.

A sample should only be taken after the pretest has indicated sufficiently high permeability to be able to sample within a reasonable amount of time.

The maximum amount of time to fill a sample chamber can be calculated using:

$$t = \frac{63.1 \text{ x } V \text{ x } \Delta P_{pt}}{Q_{pt} \text{ x } P_f}$$

where:

- $t$ = sampling time (min)
- $V$ = volume of the sample chamber (gal)
- $P_{pt}$ = pressure draw-down during pretest (psi)
- $Q_{pt}$ = flow rate during pretest (cc/sec)
- $P_f$ = formation pressure (psi)

When a sample is taken, the pressure should be allowed to build up for at least 1.5 times the flowing period before the chamber is closed. After recovering the sample, the pressure should be recorded for another two minutes.

5. **Availability of sampling equipment and containers**

The sampling equipment supplied by the testing company includes:

- the Christmas Tree
- “high-pressure” transfer hose
- “low-pressure” transfer hose
- the gas/liquid separator

- gas meters

Sampling containers are the responsibility of the oil company. These include:

- stainless steel “high-pressure” gas bottles
- atmospheric sample bottles for liquids

Any cross-over connections that may be required between the hoses and the sample containers is the responsibility of the oil company.

Samples which are required for PVT analysis should not be bled off, but removed from the tool while still under pressure. These should be clearly marked “Caution High Pressure Sample”.

**6. Familiarize yourself with the contractors tool**

When formation testing has been decided upon, it is the responsibility of the Wellsite Geologist to familiarize themselves with the testing tool and testing procedures. It is best to request a catalog and/or service bulletin from the service company. When the tools and engineers arrive on location, question the engineers about the tools operation and procedures in case of malfunctions.

As with other formation evaluation tools (wireline sondes, MWD tools, gas detectors), proper calibration of the formation testing tool is a vital component in the tool's operation. Primary calibration is accomplished using a precision dead weight tester, which is used to apply a known pressure to the strain gauge while maintaining the electronics at a known temperature. This should be performed every 3 months. Secondary calibration is done downhole, using an internally generated reference signal.

Several contractors provide formation testing services. The most common tools and calibration procedures include:

**Schlumberger: Repeat Formation Tester (RFT)** - This tool generates a calibration signal downhole, then the readout is adjusted to 9995 psi (for the 10K psi gauge), and 19995 psi (for the 20K psi gauge).

**Atlas: Formation Multi-Tester (FMT)** - The FMT is calibrated using two reference signals generated by the tool. In addition, FMT's have a “Variable Pressure Control (VPC)” which allows the test engineer to control the drawdown from the surface during sampling.

**Welex: Sequential Formation Tester (SFT)** - The SFT is very similar to the RFT, except that only one 20 cc pretest sample is collected every time the tool is set. The hydraulic pressure pad can be set at the surface to a suitable pressure for the formation to be tested.

**Gearhart: Selective Formation Tester (SFT) -** This SFT is also similar to the RFT in design and calibration, except that there is a hinged connection above the sample chamber to minimize tool sticking. It also has a variable pretest chamber.

**BPB: Repeat Formation Tester (RFS) -** The RFS is similar to the RFT. During downhole calibration, two reference signals are generated by the tool.

7. **Report all unusual observations to the company man and client engineer**

In order to detect anomalies, a graphical output of pressure versus depth is plotted during the recording stage. Any suspect points should be re-tested, several feet (± one meter) above or below the suspect depth. This will enable interpretation to be made at a later date. Several points to note are:

- A setting failure can be noted when a rapid return to hydrostatic pressure is seen, instead of the expected formation pressure.
- Impermeable sections can be recognized by a zero or negative pressure readings during the pretest.
- Abrupt variations in the hydrostatic gradient can be indicative of nonstabilized pressure readings. Gradual changes may be due to a dropping fluid level or the settling-out of the solids in the mud system.

Other problems that can occur during a formation test are listed starting on page 11-14.

8. **Ensure consistency with all test reports**

As with #2, the contractor reports and the reports filled out by the Wellsite Geologist, should contain the same information. The data concerning pressures and sampling times should not differ. The interpretations may be different, but the type of information contained in the reports should be the same.

The Wellsite Geologist should review the service company's report form to ensure consistency in format and information that must be entered. All inconsistencies should be “ironed out' before the test begins.

The type of information includes:

| General Information | Formation and Mud Data |
|---|---|
| Test Number: | Formation Name: |
| Depth: | Porosity (%): |
| Test Type: (open hole or cased hole) | Rt (@ $^{o}$F): |
| Tool Type: | Rw (@$^{o}$F): |
| Probe Type: | Water Saturation (%): |
| Flow Control: | Rmf (@$^{o}$F): |
| Tool Number: | NaCl (ppm): |
| Sample Unit Size (cm$^3$) | |

| Pressure Data | Recovery Information |
|---|---|
| Initial Shut-In (psi): | Gas (m$^3$): |
| Build-Up Time (min): | Distillate (cm$^3$) and API Gravity: |
| Sampling Range (psi): | Oil (cm$^3$) and API Gravity: |
| Sampling Time (min): | GOR: |
| Final Shut-In (psi): | Water (cm$^3$) with NaCl (ppm): |
| Final Shut-In Time (min): | Drilling Fluid (cm$^3$) and Sand (cm$^3$): |
| Hydrostatic Pressure (psi): | Formation Water (%): |
| Surface Chamber (psi): | |

It is the Wellsite Geologist's responsibility to ensure consistency with the reports and reporting procedures. This responsibility for consistency also includes all interpretation and remarks concerning the test.

**9. Properly dispatch all samples, charts and reports**

The Wellsite Geologist should have all addresses for shipping samples, paperwork and logs. If any discrepancies are noted, the correct shipping addresses should be confirmed by the client.

**10. Service tickets of the contractor must be approved, signed and sent to the client engineer**

Before the service company leaves location, the service tickets must be reviewed by the Wellsite Geologist, the company man, and the test engineer. The services rendered must be agreed upon and the service ticket signed by all parties. One copy is retained at the wellsite, one given to the service company, and one sent to the client's office.

**11. Upon returning to the office from the wellsite, review the test with the client engineer**

When the Wellsite Geologist returns from the wellsite (i.e. completion of the well, rotation schedule, etc.), the geologist should contact the client engineer responsible for the well to discuss the formation test procedures and results. Follow-up on such an important aspect of formation evaluation is necessary. This discussion will allow both engineering and geological aspects to be discussed and evaluated before completion work is initiated.

## Output Recording

During a formation test, a film recording is produced for each completed operation (see Figure 11-3). The recorded measurements are based on time rather than depth (because the tool is stationary in the borehole), where each time grid represents two seconds (rather than two feet on a depth-based log).

Track 1 contains the pressure measurements, as analog traces, which provides a quick-look analysis of packer seating and formation permeability. Pump pressure is sometimes included in Track 1, as a dashed trace, to assist in the determination of packer setting and retraction. Tracks 2 and 3 are subdivided into half-tracks, with digital scales of the recorded pressures (units, 10's, 100's, 1000's).

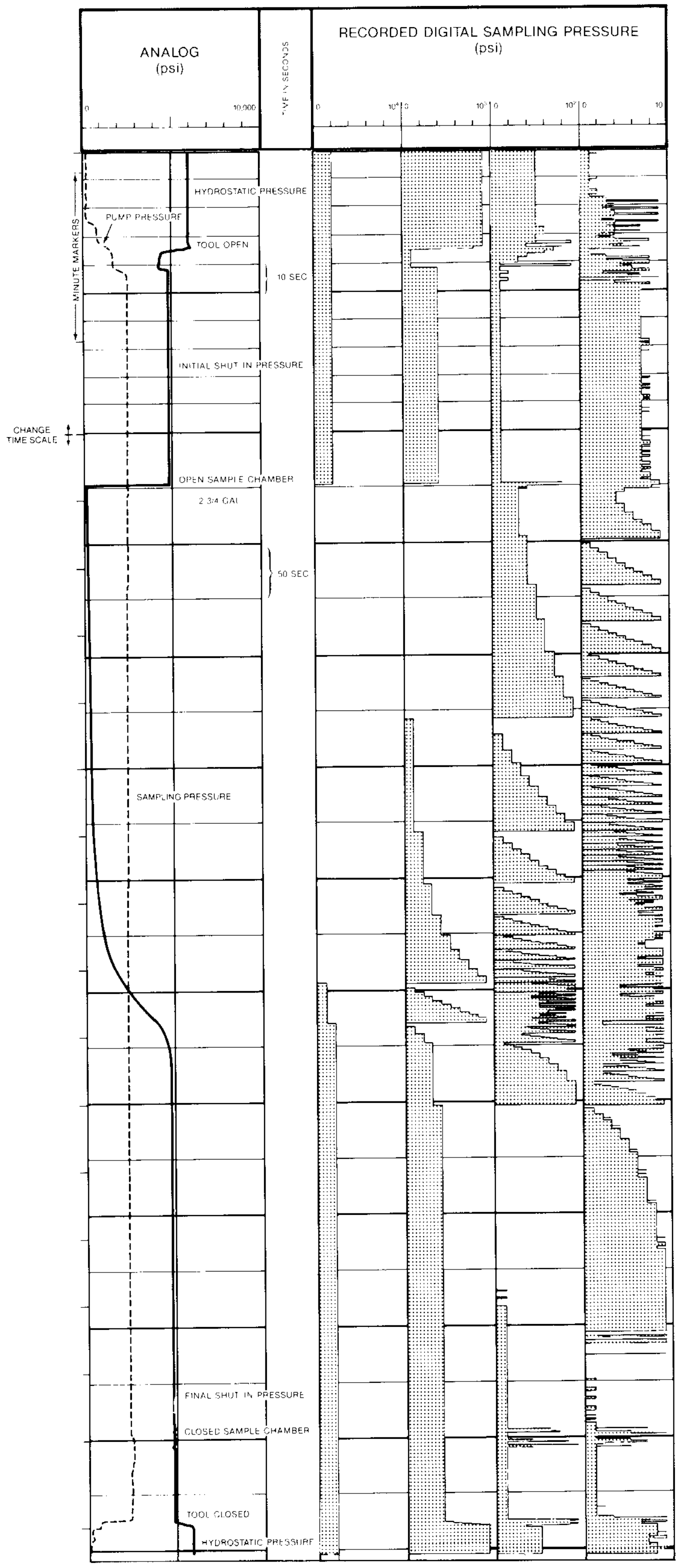



**Figure 11-3: Film record of pretest and sampling steps**

## Problems When Running Wireline Formation Tests

### Seal Failures

These comprise the majority of failures. They occur when drilling fluid leaks between the borehole wall and the surface of the seal pad. A seal failure will almost certainly occur if an attempt is made to set the tool in a zone where the borehole wall is very irregular or where the borehole is washed-out to a diameter greater than that of the fully expanded tool.

#### Primary Seal Failures

These occur immediately when sampling is initiated. They are caused the breakdown of the formation surrounding the pads or the rubber of the seal pad splits due to the high differential pressures induced across the seal at the time of sampling. They occur in low permeability formations.

#### Secondary Seal Failures

These occur at a later stage in the test. They are generally due to a gradual break up of the formation under the seal pad as a result of high inflow rates. Such failures can be prevented by changing to smaller choke sizes.

### Tool Plugging

During the sampling period, it is common for a considerable amount of formation solids to be carried into the sample chamber by the produced fluid. Occasionally, these solids become stuck in the flowline or associated parts and build-up to form a plug. When testing soft carbonates, it is found that lumps of rock can enter the flowline when sampling is initiated. It is thought that the rock breaks apart under the high initial drawdowns.

It is not always possible to differentiate a plugged flowline from a test in a low permeability formation during a test, but inspection of the tool at the surface will immediately reveal the difference. If a plugged tool is suspected, the test should continue as normal, but the sampling period should not be extended beyond fifteen minutes (in hope of obtaining a full sample chamber). It is possible to obtain good shut-in pressures in the flowline after closing the seal valve, as the volumetric inflow required for these is very small.

A different phenomenon which has the same characteristics as a plugged flowline is sometimes experienced in soft carbonate formations. The formation can be compacted by the pressure of the seal to such an extent that its permeability is reduced to nearly zero.

Improvements in the design of the RFT sampling probe has reduced the chances of tool plugging problems.

## Mechanical Failures

Failures in the hydraulic or electrical systems may prevent the tool from operating properly. If the failure is clearly recognizable, the test should be aborted and the tool pulled to the surface for inspection. However, the test should be continued if indications are not conclusive, followed by a close inspection of the tool after the test and it is at the surface.

## Stuck Cable

The “yo-yo” technique has been developed to reduce the chances of the cable becoming differentially stuck during the test. As soon as the tool is set, approximately 2 feet per 1000 feet of cable are slacked-off. Then about 1 foot per 1000 feet are then alternately reeled-in and slacked-off continuously (at ± 750 ft/hr) until the end of the test. At this time all the slack is taken up and the yo-yoing stopped. In this way the cable is never allowed to remain stationary during the test.

This technique should not be done in deviated boreholes (> 15°) as it may lead to keyseating. It is not necessary in cased holes or in carbonate formations, as there is little risk of differential sticking.

During the test, a careful watch must be kept on the cable tension indicator. The cable tension should follow an identical pattern through each “yo-yo” cycle. Any changes in the tension pattern may indicate the cable is becoming stuck or keyseated. In such cases the test should be aborted and the tool pulled out of the hole.

If the cable becomes stuck, the jar at the top of the tool cannot be operated, and the only recourse is to fish the tool with drillpipe using the over-stripping method.

## Stuck Tool

There are times when the formation test tool becomes stuck, while the cable remains free. This can happen if a dump valve fails or the pressure across the pads is not equalized, causing the seal and back-up pads to “dig-into” the formation when the tool is dumped. The tool can also become deferentially stuck.

If this occurs, the cable is pulled in tension. At 3000 lbs overpull (allow for the weight of the cable in the hole), the shear-pin in the hydraulic pressure system will break, equalizing the pressure in the hydraulic system with the mud pressure. At approximately 4000 lbs overpull, the hydraulic jar at the top of the tool operates. If this does not free the tool, it must be fished.

## Fishing

Fishing of formation test tools is the responsibility of the client's engineering department.

## EXAMPLE RFT REPORT

(To be filled in while running the formation test)

Well Name: ____________________ Run Number: _____ Date: ________________
RKB: _____________ Hole Size: _________ Hole Deviation: ___________________
Mud Type: _____________________ Mud Density: __________ Viscosity: ________
Water Loss: __________ Salinity: ___________ pH: ______ Resistivity: ___________

Depth Control with: _________________________ log

Pre-Test Data

| Setting Number | Depth (ft) | Mud Pressure | Tool Set Time | Final Pressure | Tool Unset Time | Operation Yes/No | Remarks |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |

Yes/No - Operation satisfactory, agreed upon between Wellsite Geologist and test operator at wellsite

Sampling Data

| Chamber Position | Size (gal) | Setting Number | Depth (ft) | Time Opened | Final-Flow Pressure | Time Closed | Shut-in Pressure | Time Unset |
|---|---|---|---|---|---|---|---|---|
| **Top** | | | | | | | | |
| **Bottom** | | | | | | | | |

Maximum Temperature _______°F at ____________ft at ________ hours after last circulation.

Setting Numbers must correspond with test company record

Chapter 12

# Wellsite Velocity Surveys

The following information is an introduction to downhole seismic services and list some generalized procedural guidelines to be followed by the Wellsite Geologist when velocity surveys are being taken at the wellsite.

Though this is a guide, most service companies providing downhole velocity/seismic services will follow similar procedures, and only details of the operations will vary from company to company.

In general, the Wellsite Geologist's responsibilities involve:

- Monitoring signal noise and signal quality (noting first arrival times and noise by observing the monitors within the recording unit)
- Station level and depth
- Facilitating the set-up of equipment and interaction with the company man and workboat (when using a movable source for walkaway-type surveys)

Vertical seismic profiles (VSP) generally give better resolution than surface seismic methods, mainly because the sound wave has less distance to travel and therefore is less attenuated. The main reason VSP's are not performed routinely at the wellsite is because of their cost.

These types of surveys can be taken in both open and cased holes.

## Service Companies

Since velocity surveys are a high cost operations, only the major oil-field service companies offer them. Primary wellsite velocity (seismic) survey companies are:

- Western Atlas Wireline Services
- Halliburton Logging Services
- Schlumberger Logging Services

The companies usually supply logging engineers to run the surveys, though some may include a seismic engineer, to acquire and process the data.

The company will also supply the downhole sonde with geophones (receivers), the surface acquisition equipment, and the shooting equipment.

Whenever velocity surveys are taken offshore, a navigation/positioning company will be required. When they are used, the following data is required to accurately position the workboat (energy source).

- Spheroid (Ellipsoid) System Location
- Datum Station Coordinates
- Projection (feet/meters Easting and Northing)
- Type Projection (Transverse Mecator, in degrees longitude & latitude)
- Datum Parameters

## Wellsite Velocity Survey Types and Objectives

### Velocity Surveys

Velocity surveys are travel time measurements acquired with receivers at known depths in the well bore, to arrive at accurate time-depth and seismic velocity results. They are used for calibration of surface (seismic) and downhole (wireline) log data.

The types of surveys include:

- Stationary Source types (the source is near the well bore)
- Vertical Incidence types (a moving source directly above the downhole receiver(s) in deviated holes)
- Ray-traced types (modeling to correct for velocity anomalies, well deviation and steep geologic dip)

Surveys are usually used for acoustic(sonic) log calibration, production of synthetic seismograms, and other time-depth related plots or projections.

### Vertical Seismic Profiles

Vertical seismic profiles are seismic waveforms measured directly in the borehole. They can be used to image the subsurface; either near, away from, or underneath the formations to better delineate reservoirs, faults and pinchouts. VSP data can be directly correlated to well logs and surface seismic sections.

VSP types include:

- Vertical Profiles
  1. Zero-Offset VSP’s
  2. Zero-Offset VSP’s with VSP-CRP transform (for deviated boreholes or dipping geology)

- Offset Velocity Seismic Profiles
  1. Offset VSP with VSP-CRP transform (for horizontal layers, straight or deviated boreholes and simple geologic structures)
  2. Complex Offset VSP with VSP-CRP transform (for complex layers, straight or deviated boreholes and complex geologic structures)
- Moving Source Vertical Seismic Profiles
  1. Walkaway VSP (for straight or deviated boreholes)
  2. Vertical-Incidence VSP/Corridor Stack or VSP-CRP transform (for deviated holes involving a moving source directly above a downhole receiver)

Surveys of this type of survey are used for VSP migration analysis, seismic inversion analysis, and a complex type of 3-component model-based rotation velocity survey analysis.

### Salt Proximity Surveys

These surveys measure seismic energy propagating through and around salt structures. Images are achieved from boreholes near or passing through diapirs or other salt structures. They are used to map complex salt surfaces where surface seismic is ambiguous.

These surveys can provide:

- 2-D Salt Profiling (solution in a 2-D plane)
- 3-D Salt Profiling (solution in 3-D and model based 3-D ray-tracing)
- Walkaways
- 2-D Salt Profiling with 3-Component Error Analysis

## Shear Wave (S-Wave) Surveys

This survey method uses 3-component receivers to measure the complex progagation of shear (S) waves. These S-waves can be used in porosity calculations, lithology and pore fluid identification, and vertical fracture orientation.

Types of surveys include:

- S-Wave Velocity Survey (Vp/Vs ratio) with the source near the well head
- Zero-Offset and Offset S-Wave VSP: with the source far away, multiple sources or walkaway-type
- S-Wave Birefringence

These surveys are used for acoustic (sonic) log calibrations, producing synthetic seismograms, multi-component summations, and for “Alford rotation” analysis.

### Fracture Monitoring Surveys

These surveys are used to monitor hydraulic fractures, and used to determine the direction and extent of induced hydraulic fracturing.

## Survey Equipment Requirements

As mentioned earlier, the logging company will provide the tools necessary to perform the velocity services. The typical equipment required to run velocity surveys falls into three general categories:

- **Energy Sources**

  1. Compact Sleeve Gun Array
  2. Tuned Air-Gun Arrays
  3. Compressional and S-Wave Vibrators
  4. ARIS Impulsive Source
  5. Explosives

  When using air-gun sources, the air-gun pressure should not fall below 1900 psi when shots are made.

- **Receivers (Geophones)**

  Single and Multiple Receiver Downhole Tools using;

  1. Wireline Logging
  2. Pipe Conveyed Logging (PCL)
  3. Tubing Conveyed Logging (TCL)

- **Analysis**

  Velocity survey processing and analysis generally requires the use of Sun Workstations, using Unix-based software.

## Wellsite Procedures and Recommended Practices

Wellsite velocity surveys are sometimes referred to as “checkshot survey” and can, depending on the intent, be a simple process or a lengthy, relative involved survey.

The most simple and basic survey involves making between 15 to 30 checkshot levels/stations in a vertical wellbore using an air-gun hanging over the side below sea level, with no wellsite processing required.

On the other extreme, a full walkaway survey, performed in a highly deviated well requires a work boat, full navigation company, 50 to 100 shot levels/stations, multiple guns, a complete wellsite location site survey or rig move survey. Also included will be a spheroid system, datum and datum parameter information (this data is required by the navigation companies for pinpoint satellite positioning for wellsite and seismic line locations). In addition all processing will be accomplished at the wellsite.

When a wellsite velocity or checkshot survey is listed in the well prognosis, every effort should be made to define exactly what type of survey is required, and when and where the data processing will be done.

### Timing of the Velocity Survey

An important component in the survey process is determining when the survey operations will be conducted. The most common timings are:

- At the final or TD logging runs - either before or after casing
- At an intermediate logging run - to check interval velocities in order to make corrections to the drilling program (generally on exploration wells)

Velocity surveys can be run at any point in the logging run, except directly after sidewall cores. If this is necessary, then a wiper trip will be required after the sidewall core run to condition the hole.

Regardless of when the survey is taken, the wireline and navigation companies need at least 48 hours notice to mobilize. If an offshore walkaway survey is being run, the company leasing the work boat will require the same amount of preparation time.

### Choosing Levels/Stations

Because of their knowledge and geologic expertise, the Wellsite Geologist may be involved in shot point determination. If nothing else, since they will have been at the wellsite during drilling operations, they will be asked to provide accurate formation/horizon tops.

Generally, the Operations Geologist or Geophysicist will choose the level/stations (depth intervals) for the checkshots. The Wellsite Geologist should attempt to get this information as soon as possible (i.e. before the casing/liner is run and the plugs set). If the checkshots are required in the deepest part of the borehole, the Wellsite Geologist may have to suggest an open-hole survey. Find this out before the casing is run.

The levels/stations are picked based on the depths of the primary targets and primary mapping horizons, so the travel times and interval velocities can be accurately determined. Spacing can be as little as 100 feet in the primary zones of interest and 500 feet above these zones to the surface.

Information required for station or depth determination includes:

- Casing Points
- Sonic Logs
- Caliper Logs
- Deviation Surveys
- Geological Tops

Several items to keep in mind when looking for shot point depths include:

- Do not take checkshots near casing joints.
- If "cycle skipping" is noticeable on the sonic logs, shots should be taken above and below this area.
- Where sonic logs are joined (i.e. between logging runs), take enough shots to ensure good coverage over that interval.
- Review the caliper log to ensure that the arms on the receivers will be able to clamp to the open hole.

Oil company philosophy varies as to how many shots are needed for a complete survey. Part of this is due to exactly how many shots are required to get the final output, a synthetic seismogram. Most of the time it only requires no more than 50 depth intervals per survey.

## Walkaway Velocity Surveys

### Logistics

Walkaways are one of the most time consuming and logistically demanding types of velocity surveys. Since the other types are less involved, there is less geological interaction required.

A walkaway velocity survey takes planning and coordination between the wireline company, the navigation company, the company man, workboat captain (use of the workboat for between 15 to 30 hours), the tool pusher and crane operator (utilizing the crane for 12 to 24 hours), the company drilling department (for the navigation company positioning survey of the rig or the original platform survey, if a platform is being used), and the Geology/Geophysics department (for the number of surveys, type of survey, processing and output required, and radius of accuracy for the source position).

Typical set-up times for a full survey will take about 8 hours, prior to running into the hole (RIH) with the receivers. The survey will take between 6 to 12 hours (25 to 50 levels) depending on the number of levels and amount of noise.

The energy source (usually an air gun) should be placed a minimum of 10 feet from the hull of the vessel or workboat (most captains will also want the source 30 to 45 feet below the hull to prevent damage to the boat's electronic systems).

Some workboats even have a crane on the main deck, which can be used. The workboat should also have "mid-hull positioning thrusters" to help maintain the boat's position while shooting and recording the survey.

As a rule of thumb, once the workboat is positioned within the source target area (as previously defined by the Geophysicist) it only takes between 3 to 4 shots to complete each level (if the signal is repeatable and noise free). Most of the time is spent positioning the source and receiver. An example of the wellsite layout can be seen in Figure 12-1.

The wireline company will generally subcontract a navigation company, and this will often be stated in the oil company's contract.

The wireline and contractor should have their equipment/communication bugs worked out before they reach the wellsite, however the Wellsite Geologist should start pressing them as soon as possible.

Important items to check are:

- Ensure the downhole receiver clamping mechanism is operative
- Gun firing and pressure gauges operate to company standards
- The depth recorder is zeroed by suspending a receiver at the RKB
- The gun hydrophone should have a clear time break register for time-zero pinpointing

Some fine-tuning will probably be required after the rig and workboat set-up, but this should be completed by the time the operations are turned over to the wireline company and before running into the hole with the downhole receivers.

Ensure that all deviation data, wellsite location data and coordinates are available to the navigation company so they can calculate the vessel position (energy source position) accurately, which can be directly above the downhole receiver in deviated wells.

The wireline company will provide a rig energy source (which is extended over the side and in the water using one of the rigs cranes) for timing/ equipment checks. This energy source should be activated for all checkshots to ensure accurate acoustic log calibration.

### Logging Procedures

Following the set-up and testing of the navigation and logging equipment, the logging engineer will monitor for background (rig) noise. This noise information is used to filter out the noise which could create problems when the signal shot is received by the geophones.

The engineer can usually break the noise down into specific frequencies and then determine when “new” noise is present as the survey progresses. The main causes of noise are the rig’s motors, paint chippers, other workboats, nearby fishing boats, line tension downhole, and slack cable lying against the casing/liner. To reduce wave-related noise, offshore shooting should be done when sea-swell noise is at its lowest. Lulls of a few seconds duration (or more) may occur every 30 to 60 seconds. If they do, shoot during these lulls.

As a preventative measure, all unnecessary rig machinery should be shut down, and as far as possible, all extraneous noise sources should be eliminated.

After the tool is zeroed at the drill floor, it is run into the hole. On the down run, 2 or 3 calibration/collaboration checkshot levels are made to ensure repeatability, and that a quality, noise-free signal is received. The general criteria for repeatability is:

- A clear arrival time
- Shots from the same depths are within 0.5 ms of each other

These shots can be made at shallow depths or at specific, deeper horizons as a re-check of travel times. These points will need to be tied into the energy source positioning if they are in a deviated or off-set portion of the hole. Coordination with the navigation company is necessary.

When the energy source (workboat) is in position, within the pre-selected target area (a circle with a 100 to 300 foot diameter), the shots are fired by remote-control by the logging engineer on the rig. The engineer can monitor the workboat/source position via a digital display in the logging unit (this display is generally supplied by the navigation company).

Most companies have monitors and displays that allow for easy, quick assessment of the data quality. Normally, 3 or 4 shots are made at each level, assuming the signal is clean and the travel time is repeatable. The signals are then processed, stacked and recorded to tape, along with the source location, for that particular field.

The receivers will then be run to TD to begin the uplog sequence. When each level is reached, the receivers are centralized in the hole using expandable arms. The cable is frequently slacked about 10 feet and the shots fired and recorded.

There will be times when cable slack is unnecessary, for example if when the cable is resting on the casing and excess cable vibration causes unacceptable noise.

Once in the hole, operations should take about 6 to 8 hours, for 25 shots if the signal is noise-free, the hole is 8,000 to 12,000 feet MD, and no tool or source problems occur.

If it is necessary to run the survey in two parts (receiver failure, problems with surface equipment, etc.), there should be an overlap (about three shots) of repeat shots.

Problems generally arise from noise that interferes with signal reception, from energy source (air) leaks, from air compressor failure, and from communication difficulties.

## Summary

Velocity/checkshot surveys can be run with PCL or TCL, as required. The receivers can also be run with other logging tools in open hole or cased hole if the need arises.

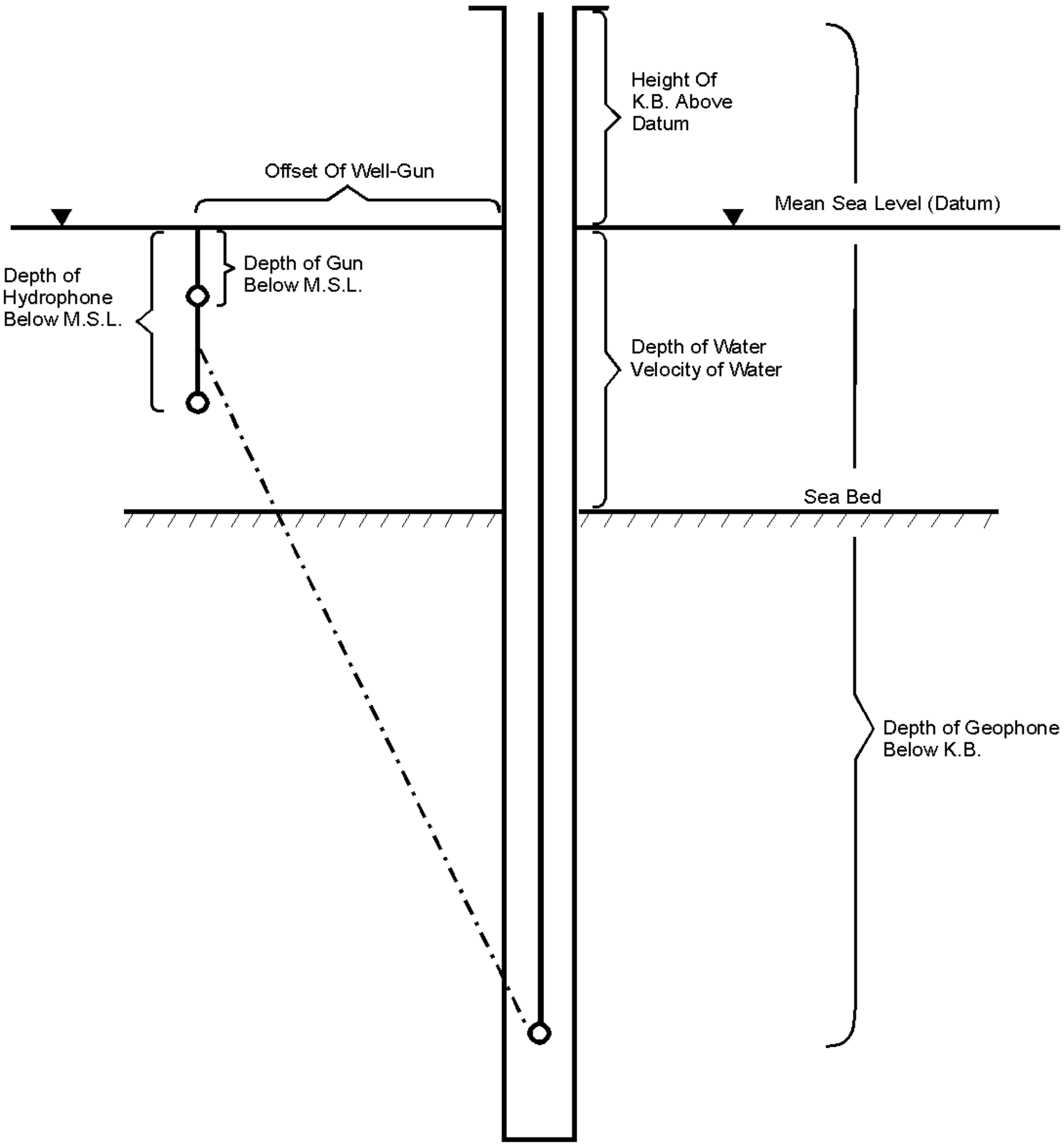
Examples of data output should be included in the well prognosis (i.e. processing of checkshot data, “complete” VSP processing, sonic calibration from checkshot data, synthetic seismogram, etc.).

The Wellsite Geologist should note the following when recording velocity survey information:

- Retain one analog record from each level
- Review the checklist geometry (Figure 12-1) before the end of the survey
- Note offshore sea-level variations at and during the survey
- Compare the calculated interval velocities with the sonic log

It should be remembered that the logging engineers may not be able to process the data. They may not know the software program, and most logging engineers are not seismic engineers, signal analysts, nor seismic processing trained. It is best to find out which company will be used for the surveys and determine their expertise before requesting wellsite data processing.

As a general rule of thumb, the cost estimate for a walkaway-type survey, in a 12,000 foot hole, taking 40 shots is approximately $25,000. There are generally fixed charges for the first 20 shots. These charges do not include workboat time (acting as the source vessel), however, in normal field use workboat time is figured into the daily well costs.




N.B. Geometry for Offshore but Easily Adaptable for Onshore

**Figure 12-1: Velocity Survey Layout**

Chapter 13

# Wellsite Communications

## Geologic Decisions During Drilling Operations

There are many instances where the Wellsite Geologist can assist and influence decisions that must be made to make the well successful. Careful scrutiny of the many sources of geologic information, combined with a knowledge of the engineering principles behind the operations, will allow the Wellsite Geologist to be a valuable member of the drilling team.

The criteria for the selection of coring points has been described in Chapter 7. Several other important decisions which require geologic information are listed below.

### Selection of Open Hole Formation Test Intervals

Running an open hole formation test is generally the least time consuming method to obtain information about a reservoir. The information collected is mainly concerned with formation pressure evaluation. Fluid samples are usually too small for complete reservoir analysis purposes, but can provide indispensable preliminary information and confirmation of mud log, MWD log, and wireline log results regarding the nature of formation fluids.

To prepare for possible formation testing, the DLL/SONIC/GR/SP and FDC/CNL/GR/CAL logs, (or their equivalents) must be reviewed to determine the characteristics of the sections to be tested. The mud log should be reviewed to confirm the wireline log analysis and to ensure that no pertinent items not noted on the wireline log, concerning the formation, have been overlooked.

The intervals selected for testing should have good porosity, good permeability, and clearly defined bed thickness. The hole should be in gauge with some mud cake (though excessive mud cake may cause tool plugging or seal failure). It is best that any hydrocarbon sampling be attempted towards the end of a run, near the top of a homogeneous, high permeability bed to take advantage of the possible gravity separation of the mud filtrate and hydrocarbons.

Accurate depth control is an absolute necessity in formation testing. Review all possible sources of depth determination (geolograph, mud log, wireline log) to ensure that the proper depth is selected. These depths include:

- The exact depth of the top of the formation (the base may not have been penetrated)
- Pick the testing point, usually 2 to 3 feet into the top of the formation
- Approximate total thickness of the formation to be tested
- Determine that the total depth (TD) is accurate
- Calculate the distance from the packer point to the bottom of the hole

Several circulations of the mud system are usually necessary to ensure the hole is clean. During these circulations, the drilling fluid can be "conditioned" to minimize caving and filtrate loss. The mud engineer should be able to give an accurate measurement of the filter cake to be expected across the formation.

When special pressure studies are required about the formation (e.g. gas reservoirs), absolute accuracy is necessary. In this case the formation tester should be run with a high precision quartz gauge

## Selection of Casing Points

The Wellsite Geologist will probably have to supply lithological data, information on formations which may cause drilling problems, and predictions on formation pressures (pore pressure gradients and fracture pressure gradients) to the rig personnel to assist in the selection of the most optimum casing point.

If the client has specific depth/formations where they want to set casing, the mud-logging personnel should be advised so they can concentrate their efforts when that formation is approached. Close monitoring of the drill rate, drilling parameters and a reduced sample interval (i.e. every 2 feet) will help pin-point the depth/selected formations.

The "general" technique for determining casing point is when approximately 10 feet above the desired depth:

- Tell the driller to keep the WOB constant
- Observe the drill rate during drilling
- Circulate bottoms-up for cuttings samples
- If the cuttings match the desired lithology, contact the company man

Close observation of correlation logs and drilling reports will help locate problem formations. Since every well is different, problem formations appear higher or lower than expected. The often quoted “plan of action” is to drill through a problem formation, then “case it off”. Trying to set casing as deep as possible has it's own drawbacks. Several points to take into consideration are:

- It takes time to drill large diameter boreholes
- There are increased more mud costs in large diameter boreholes
- Large diameter casing costs more than smaller diameter casing
- Many borehole problems can be alleviated using the mud system

It can often be better to set casing above problem formations, then optimize the drilling fluid and drilling parameters, to prevent the problems from occurring.

In selecting casing points, items to keep in mind are:

| Surface Casing | Intermediate Casing |
|---|---|
| Unconsolidated Surface Sands | Abnormally Pressured Shales |
| Lost Circulation in Subnormal Sands | Sloughing Shale and Hole-Fill |
| Seepage Lost Circulation | Lost Circulation |
| Bit-Balling and Annular Loading in Clays | Acid Gases |
| **Production Casing** | |
| Abnormal Pressured Shales | |
| High Mud Weights (slow drilling) | |
| High Bottom Hole Temperatures | |
| Slow Drill Rates | |

Optimizing the costs of casing runs requires much pre-well planning and on-site observation. Close contact and constant communications with the drilling engineer will help solve this tricky and expensive operation.

## Recommending Sidetracking

There are two principle reasons for sidetracking; geological and economical. Geological reasons include missing target formations during initial drilling (due to faulting or facies changes), following a fault plane instead of crossing it, or drilling a formation and missing the hydrocarbon-bearing portions (generally located further up-dip). For example, if the well is drilled to produce oil, and the target formation is gas filled, with no indication of water or oil, it is geologically feasible and economically justified to sidetrack than it is to drill another well to search for the oil - bearing portions of the formation.

Economic decisions regarding sidetracks revolve around some borehole problem (stuck pipe, underground blowouts, etc.) which causes the drilled borehole to become unusable.

Economic reasons however, may be the only consideration available. Such re-drilling usually occurs where there are high daily operating costs. If a formation is missed, sidetracking may be the only way to complete the well (more cost-effective than drilling a new well). Several other examples for sidetracking include; fault drilling, multiple formations from a single well, salt dome drilling, multiple exploration wells from a single borehole.

When sidetracking around stuck pipe or lost drillpipe, the "classic" method is to determine the cost of sidetracking versus the cost of fishing for the stuck or lost portions of the drillstring. For example:

Value of Material

| | |
|---|---|
| 800 ft of Drill Collars @ $22.00/ft = | $ 17,600 |
| 300 ft of Drill Pipe @ $8.00/ft = | $ 2,400 |
| Total Salvageable Material | $ 20,000 |

Estimated cost to plug-back, sidetrack and re-drill:

| | |
|---|---|
| 12 days @ 6,500/day | $78,000 |
| Total Value of Material and Hole | $98,000 |
| Estimated cost to washover and fish: | $ 7,200/day |
| Maximum days for profitable fishing: | 13 days |
| Average recovery required per day: | 85 feet |

There is an oilfield "rule of thumb" which states that fishing operations should cease when the cost of the fishing operations reach one-half the cost of a sidetrack. In the above example, this would reduce the fishing days to 7 and increase the "fish" recovery rate to 157 feet per day.

The calculations for this problem are easy to perform, and the Wellsite Geologist should attempt the calculations in order to justify any geological decisions. By knowing the economic justifications of sidetracking operations, the Wellsite Geologist has a powerful tool at their disposal when the pros and cons of sidetracking are discussed.

### Recommending the Termination of a Well

If a well is to be completed after penetrating a particular horizon, or drilling a specified distance past a certain formation, it is essential that the Wellsite Geologist keep in constant communication with the Operations Geologist, passing on as much information as possible. Correlations should be discussed and possible stopping points agreed upon.

It is unlikely that the decision to stop drilling will be the sole responsibility of the Wellsite Geologist, but it is essential that the necessary wellsite information be passed on to ensure that drilling is not stopped early or continued into unproductive formations.

Many times wells are drilled to test a stratigraphic play or structure. In the event that the geology is not as expected, it is essential that the information pertaining to these features is passed on as soon as possible.

Other geologic reasons for suggesting that drilling be stopped are:

- When the targeted formations have been drilled
- When the geologic basement has been reached
- When the geothermal "Hydrocarbon Generation" window has been passed

As mentioned earlier, it may not be the Wellsite Geologist's decision to cease the drilling operations, but the information provided to the operation's departments will be valuable for them to reach a decision.

## Documentation & Reporting

Any important operational matter discussed over telephone or by informal fax should be backed-up by a "formal" written copy, and filed. All faxs/ telexes from the wellsite should be copied to the Operations Base (both Geological and Engineering Departments).

### Daily Reports

Once the geologist has finalized their interpretation of the cuttings and drafted the lithlog, they must report this information to the Operations Base in some written format (fax, telex, modem, etc.). The daily report summarizes all the geological information from the previous twenty-four hours (usually ending at 0600). The information should be transmitted as soon as possible after 0600 and sent along with the drilling report.

The oil company will probably have its own daily communication report, however in any event, the daily report should include:

| | |
|---|---|
| **Well Name** | The well name, number and location. |
| **Date** | The day, month and year. |
| **Report Number** | The consecutive number of the report, starting from one. |
| **Days Since Spud** | Number of days since the beginning of the well. |
| **Depth at 0600** | Always confirm the depth with the company man's report. |

Depths must be consistent. When drilling a deviated well, depth must be stated as measured depth (MD) and true vertical depth (TVD).

**Progress**

State the wells progress over the past 24 hours. As with the depth, this information must coincide with the company man's report.

**Lithology**

This must be a selective, but concise description of the drilled section since the last report, as interpreted on the lithlog. Despite its brevity, significant changes within the section must be noted and reported. This description must describe the section as a continuous sequence, not as a series of intervals.

**Shows**

If no shows have occurred, state NONE. However, if a show has occurred, the following must be reported:

- Lithology associated with show
- Sample fluorescence (color and percent)
- Solvent cut fluorescence (color and speed)
- Color of visible staining
- Any type of petroliferous odor

A show rating or classification (poor, fair, good, etc.)

**Gas**

The range and average (in %EMA) should be reported. Significant peaks can be singled out and reported. All peaks should be reported above the background gas, which should also be reported. Gas reading should be related to lithology.

Report the chromatograph breakdown (in ppm), in the same manner as the total gas values.

Include cuttings gas, trip gas, etc. in the report

If gas ratios are being calculated, these will be included in the report

**Drilling Fluid**

State the type, density to other significant properties and any changes which have occurred over the past 24 hours.

**Formation Pressure**

A summary of the pore pressure trends as indicated by changes in the parameters used. Values for specific depths should be reported.

Comments on any pressure plots being generated should be included.

**Drill Rate** The ROP range and average drill rate should be reported and should reflect the lithology breakdown. Always split the ROP readings into depth intervals. Report any drill breaks, and accompanying flow checks.

**Comments** This section should contain:

- Formation Tops (depth, forecasted depth, criteria for picking top)
- Logging Runs (wireline, MWD)
- Correlation with Surrounding Wells
- Current Activity or Well Problems
- The client may require a summary of the last or next 24 hours

Remember, the Daily Reports will also go to partners, so any personal comments to the Operations Geologist should be sent in a separate fax.

### Daily Dispatches

Daily shipments of lithology samples, logs, or documents are handled through the routine channels at the wellsite. When dispatching samples or documents, ensure that:

1. The company man, toolpusher and the receiving party know about the shipment
2. The samples or documents are labeled clearly, properly and consistently
3. The manifest is enclosed, specifying what is being sent to whom
4. The specific sample intervals or logs which are required are indeed included.

### Weekly Geological Reports

This report is also prepared by the Wellsite Geologist. In addition to summarizing the week's activities, the report is intended to be a medium through which the Wellsite Geologist's observations of the drilled interval and its relationship with the regional geological framework can be discussed.

The report should include:

**Company Name** The complete name of the oil company

**Well Name** The well name, number and location

| | |
|---|---|
| **Report Number** | The consecutive number of the report, starting from one |
| **Period Covered By Report** | The weeks report beginning 0600 hour and ending 0600 hours |
| **Depth Interval Drilled** | This includes the depth at the beginning of the report, the depth at the end of the report and the footage drilled |
| **Summary Of Operations** | A brief outline of the daily drilling operations |
| **Formations Encountered** | Include any provisional formation tops from cuttings data, cores, wireline or MWD logs.<br><br>Mention any correlation with other wells |
| **Lithologies Penetrated** | This is not a detailed description of every lithology, but include the main characteristics and distinguishing features of each section.<br><br>Reference any changes in drilling parameters and whether or not the changes were sudden or gradual. |
| **Hydrocarbon Indications** | Comment on the fluorescence characteristics, lithology related to the show and the quality of the show.<br><br>Comment on the gas readings (total and chromatograph), and clarify any trends seen in the gas readings by interval using a table format. |
| **Wireline Logging** | Mention the log types, run number, date and depth of surveys. Highlight any depth discrepancies between the driller and wireline depths.<br><br>Comment on tie-in depth and casing shoe depths.<br><br>List any tool malfunctions or operating problem. |
| **Coring** | Comment on the interval cored, amount recovered (length and percentage, and the formation cored.<br><br>Include sidewall cores in this section, with run numbers, numbers shot, misfires, lost and amount recovered. |
| **Well Report** | State the status of the written report and status of the draft copy of the composite log. |

Remember, this report is distributed to any partners (along with the copies of the mud log and lithlog) and care should be taken to maintain a balance between factual and interpretive comments.

Other reports the Wellsite Geologist may be required to fill out (many of these are company specific) are:

- Core Report
- Wireline Logging Report
- Formation Test Report
- Service Company Review
- Final Well Report

Since these reports are client specific, they are not discussed in this manual. Specialized reporting is often the geologist's main role while in town, and should be the clients "eyes and ears" at the wellsite.

## Maintaining Data Security

As part of the client's operating team, the Wellsite Geologist should be aware of the importance of communications with others, in the working environment and in social events.

The Baker Hughes INTEQ Wellsite Geologists have a security clause in their employment agreement, and similarly, Baker Hughes INTEQ has a confidentiality clause in their Contract with clients. This forms the basis of the Baker Hughes INTEQ/client relationship.

### Tight Holes

There will be times when entire wells or designated intervals will be handled under security guidelines. Under these circumstances all data from the wellsite will be labelled "Tight Hole", "Critical Personnel" or some designation to remind all personnel of the confidential nature of the information. During such times certain areas of the rig site are labelled "off-limits" to certain personnel. Examples of such areas are the rig floor, and mud logging, MWD and wireline logging units.

#### Mud Logging and MWD Units

When wells or selected intervals are designated "tight", only authorized personnel will be allowed into the mud logging and MWD units. The words "Tight Hole" should be stamped (in red) on all prints and logs generated in those units. The original log sheets will be retained by the Wellsite Geologist. The mud logging and MWD personnel will be instructed not to discuss well information with unauthorized personnel either at the well site or on days off.

### Wireline Unit

On tight holes, it will be the responsibility of the wireline engineer to calibrate the tools and to ensure the curves are reading properly, but the well will be logged by the client's petrophysicist. During film developing, the client's personnel will ensure that the film is not observed. This may also include the rinsing, drying, trimming and marking of the logs. The wireline engineer may have access to the calibration section.

Should timing, weather or travel restrictions prevent the petrophysicist from being on site, the Wellsite Geologist may be given this responsibility.

### Wellsite/Office Communications

Generally on tight holes, lithology, drill rate, shows or geologic information is not discussed over the telephone or radio, unless the information is coded.

On “Morning Report” only routine drilling information is listed. All shows, flows, logging and coring operations are not mentioned, but sent to authorized personnel on a “need to know” basis.

## Hand Over Procedures

Proper hand-over is an essential part of the Wellsite Geologist's responsibilities, as correct hand-overs maintain long-term continuity during personnel rotation. An example of lack of continuity can be seen when there is a change of lithology when a new geologist describes the samples. The hand-over should be detailed and informative, and should cover the following points:

1. Highlight the previous drilling activities and geological information (noting cavings, tight spots, lost circulation, etc), elaborate on correlation aspects and the outgoing geologist's “feel” of where they are in the well (i.e. “I think we're almost in the reservoir, so pay attention to the drill breaks”).
2. State the status of geological supplies, including any items on order, items not working, and items in short supply.
3. Tell the oncoming geologist “where” the supplies are located, so there is little time wasted looking for core boxes, sample bags, etc. If possible make a list of where all items are located.
4. Repeat any instructions that are particularly important, especially any transmitted by telephone. Tell the oncoming geologist where the telexes/faxs are filed.
5. Give a detailed breakdown concerning the status of the service company contractors (mud logging, MWD or wireline units).

Mention any non-functioning equipment. Tour the units with the incoming geologist whenever possible.

6. Give a general description regarding the personnel at the wellsite. Comments concerning the company-mans likes and dislikes can be very useful in maintaining a smooth working environment during change-over.

7. It is useful to have a pipe tally book or notebook in which you write down all the descriptions, notes, instructions, etc. Pass this on to the incoming geologist - remember, write so it can be read.

8. If working on a 12 hour/2 geologist job, hand over your notes on tour change and debrief the other geologist. Let the radio operators know who works which hours so that the person off-tour is not always the one on the phone.

•Notes•

# Equipment, Techniques and Procedures

## Sample Examination Equipment

The material supplies for proper sample examination at the wellsite have been listed in Chapter 1. Below are some additional comments on the equipment and supplies to ensure they meet acceptable standards.

### Binocular Microscope

Binocular magnification should range from 5x to 30x. Magnification and the field of view should be great enough to reveal the essential structures and texture of the cuttings sample. Magnification should be low enough to reduce eye strain and still provide a sufficiently wide field of view for estimating percentages of the cuttings in the sample tray. A magnification of 7x to 20x is optimum for routine sample examination, while 15x to 30x is required for more detail studies, though it should be remembered that increased magnification reduces the depth of focus. The microscope should be kept clean, properly focused and the fine and coarse adjustments in good working condition. Eyepieces and lenses should be cleaned with lens paper (facial tissue or very soft cloth may be used if lens paper is not available). A Corvascope combines a microscope along with both white and ultraviolet lights, but for thorough ultraviolet light examination a separate U.V. light is desirable.

### Light Source

Artificial light is generally used in sample examination. This artificial light is produced by some type of illuminator. Several manufacturers produce optical lamps, but any lamp with a blue filter may be used. A lamp that produces a “rainbow” of colors should not be used, since it tends to mask or distort the true colors and will cause eye strain. In addition to supplying light to the sample, the entire work area should be illuminated to prevent eye strain. If a conventional microscope lamp is not available, a gooseneck desk lamp with a 60 to 100 watt bulb will produce sufficient light. Daylight is also satisfactory for illumination.

### Sample Trays and Dishes

Small flat sample trays with a dark background are necessary to view samples under the microscope. After the sample is washed in the tray and the water poured off, the sample is ready for examination. Samples are normally examined wet. There should be enough trays to allow the geologist to keep eight to ten samples available to observe any subtle changes in color, grading, etc., and allow them to be air-dried.

A white, twelve dimple, spot plate is useful for immersing cuttings in a solvent to obtain and describe a fluorescence cut. The twelve dimples allow comparisons to be made and the white porcelain provides a good background for detecting cut-test residues.

### Fluoroscope

The Wellsite Geologist should have access to an ultraviolet light box at all times when examining samples (cuttings and cores). The 3600 Å wave length is standard for UV inspection. All porous intervals should be thoroughly checked for hydrocarbons with the fluoroscope. An organic solvent should be used to distinguish between hydrocarbon and mineral fluorescence.

### Acid and Solvents

A dilute hydrochloric acid (10%) is recommended when examining samples. A carbonate staining solution of Alizarin Red S should be available when drilling carbonates. Phenolphthalein can be used to detect casing cement.

Various nontoxic organic solvents (i.e. chlorothene) are available when testing for cut fluorescence, however due to their chlorinated-hydrocarbon nature many are being discontinued. Heptane, if available, can be used.

### Pencils

Colored pencils are used when preparing stratigraphic logs. Many types of colored pencils are available, but do not use pencils that smudge and smear. Non-pencils are recommended because they allow the geologist to annotate logs more precisely. Ball-point pens make a heavy inscriptions which smear, smudge and become illegible over time. The Wellsite Geologist's strip log is a valuable collection of geologic information and the effort required to make it neat and accurate is worthwhile.

### Grain-Size Comparator

Many companies provide hard plastic comparators (e.g. Baker Hughes INTEQ P/N 18834) which can be placed under the microscope. Representative cuttings can be placed on the comparator to determine grain size, grain shape, and sample sorting. They provide a more accurate and more consistent approach to describing some of the most difficult, yet important, textural features of cuttings samples.

Comparators are generally wallet size and should be included when collecting sample description materials for wellsite work.

## Cuttings Sample Preparation

When washing cuttings samples for lithologic examination, the amount of washing should be the minimum necessary to remove the drilling fluid (so that all components are easily recognized), but not enough so that soft sample materials are washed away.

It is imperative that the “base liquid” be used to wash cuttings (i.e. fresh water for fresh-water muds or diesel for diesel-based muds). Oil-Based Muds (OBM) will require a minimum of three baths to remove the hydrocarbon-based drilling fluid. To ensure a “clean” sample:

1. Immerse the cuttings in the base fluid
2. Wash the cuttings with a detergent
3. Rinse the cuttings in water to remove the detergent

Great care is necessary so that the soft clay do not disperse/dissolve and that any hydrocarbon shows are not washed away.

Washing for microfossils should be done carefully, through several clean, graded screens (i.e. #8, #80, #170). Occasionally the “sand content” screen (200 mesh) can be used to check for the occurrence of very small microfossils.

When searching for fossils, if shales do not break down when washed in water, they can be dried then soaked in kerosene or hydrogen peroxide, followed by submergence in water. This should break down the shales and release any fossils.

To ensure that the correct samples are being described, every effort must be made to:

1. ensure the cuttings lag is correct
2. remove all sample contamination
3. use the test which assist in sample identification

## Cuttings Descriptions

After the standard procedures for sample preparation have been carried out, the cuttings sample is described using the standardized format outlined in Chapter 2. The AAPG/SPWLA standardized abbreviations should be used.

### Description of Sandstones

The following points concerning sandstones should be mentioned if applicable: Rock type in capital letters, color, degree of induration, range of grain size and degree of rounding, degree of sorting, individual grain surface texture, type of cementing material, type of visual porosity, accessory minerals, fossil content and abundance, and hydrocarbon content. For example:

SANDSTONE: light gray, hard-to-compact, medium-to-fine-grained, subrounded to rounded, moderately sorted, coarser grains frosted, cemented by clear calcite, no visual porosity, occasional dark green glauconite, trace pyrite, rare dark silt partings, no fluorescence, pale yellow cut in solvent

SST: lt gry, hd-cpct, m-f gr, sbrndd-rndd, mod srt, crs gr fros, cmt by clr calc, n vis por, occ dk gn glau, tr pyr, r dk slt ptg, n fluor, pale yel cut in solvent

### Description of Limestones and Dolomites

The following points concerning a limestone or dolomite should be mentioned if applicable: Rock type in capitals, Dunham's classification, color, degree of induration, grain or crystal size, rock texture, matrix material, visual porosity, occurrence of accessory minerals, fossil content and abundance, and hydrocarbon content. For example:

LIMESTONE: Wackestone, grayish-white, brittle, finely crystalline, scattered medium crystalline dolomite rhombs, poorly sorted, coarse organic limestone fragments, minor block fractures, trace disseminated pyrite, trace Inoceramus, rare foraminifera, orange mineral fluorescence

LS: Wkst, grysh-wh, brit, fnly xln, scat m xln dol rhb, p srt,crs org ls frag, mnr blky frac, tr dissem pyr, tr Inoc, r foram, or min fluor

### Description of Shales, Claystones, Siltstones

The following points concerning shales and other fine-grained clastics should be mentioned if applicable: Rock type in capitals, color, degree of induration, texture, cementing or matrix material, accessory minerals and materials and fossil content. For example:

SHALE: dark greenish-gray, compact-to-firm, moderately fissile, slightly silty, calcite cement, rare pyrite crystals, small dark green glauconite grains, rare ostracods

SH: dk gnsh-gry, cpct-frm, mod fis, sli slty, cal cmt, r pyr xls, sml dk gn glau gr, r ostr

### Description of Evaporites

The following points concerning evaporites should be mentioned if applicable: Rock type in capitals, color, hardness, crystal size, crystal shape and arrangement, other textural features, accessory minerals, amount and type of inclusions and fossil content. For example:

ANHYDRITE: white to light bluish-gray, dense, massive, coarsely crystalline, irregularly fractured, recemented with clear gypsum, minor pyrite crystals, finely crystalline limestone inclusions

ANHY: wh-lt blsh-gry, dns, mass, crs xln, irr frac, recem w/ cl gyp, mnr pyr xls, fnly xln ls incl

## Checklist For Sample Descriptions

| Rock Type | Limestone Dolomite | Sandstone Siltstone | Shale Clay | Anhydrite Gypsum | Chert Halite | Other* |
|---|---|---|---|---|---|---|
| Classification | X | | | | | X |
| Color | X | X | X | X | X | X |
| Hardness/Induration | X | X | X | X | X | X |
| Grain/Crystal Size | X | X | | X | X | X |
| Grain/Crystal Shape | X | X | | X | X | X |
| Sorting | X | X | | | | X |
| Luster | X | X | X | X | X | X |
| Cement or Matrix | X | X | X | | | X |
| Visual Porosity | X | X | | | | |
| Accessories/Inclusions | X | X | X | X | X | X |
| Hydrocarbon Content | X | X | X | X | X | X |

* Igneous. Metamorphic, Coal, Conglomerates

## Commonly Used AAPG/SPWLA Standardized Abbreviations

### Rock Type

| | |
|---|---|
| Anhydrite, Arkose, Basalt, | ANHY, ARK, BAS, |
| Bentonite, Breccia, | BENT, BREC, |
| Chalk, Clay, Coal, | CHK, CL, |
| Conglomerate, Dolomite, | CGL, DOL, |
| Gabbro, Gneiss, Granite, | GAB, GNS, GRT, |
| Granite Wash, Gravel, | G.W., GRV, |
| Graywacke, Gypsum, Halite, | GWKE, GYP, HAL, |
| Lignite, Limestone, | LIG, LS, |
| Marble, Sand, Sandstone, | MBL, SD, SST, |
| Schist, Shale, Siltstone, | SCH, SH, SLTST, |
| Slate, Tuff, Volcanic | SL, TF, VOLC |

### Classification

| | |
|---|---|
| Boundstone, Crystalline, | Bdst, Xln, |
| Grainstone, Mudstone, | Grst, Mdst, |
| Packstone, Wackestone | Pkst, Wkst |

### Color

| | |
|---|---|
| Amber, Banded, Black, | amb, bnd, blk, |
| Blue, Brown, Buff, Chocolate, | bl, bu, choc, |
| Clear, Colored, Cream, Dark, | clr, col, crm, dk, |
| Flesh, Gray, Green, Light, | fls, gry, gn, lt, |
| Maroon, Mottled, Ochre, | mar, mott, och, |
| Olive, Orange, Pink, Purple, | olv, or, pk, purp, |
| Red, Speckled, Tan, Variegated, | rd, spkld, tn, vgt, |
| Vermilion, Violet, White, | verm, vi, wh, |
| Yellow | yel |

### Hardness or Induration

| | |
|---|---|
| Brittle, Cemented, Compact, | brit, cmt, cpct, |
| Consolidated, Dense, | consol, dns, |
| Firm, Friable, Hard, Indurated, | frm, fri, hd, ind, |
| Loose, Medium, | lse, med, |
| Moderately, Occasionally, | mod, occ, |
| Plastic, Predominately, | plas, pred, |
| Recemented, Slightly, Soft, | recem, sli, sft, |
| Unconsolidated, Very | uncons, v |

### Grain Size

| | |
|---|---|
| Arenaceous, Coarse, | aren, crs, |
| Cryptocrystalline, Fine, Grain, | crpxln, f, gr, |
| Large, Little, Medium, | lge, ltl, med, |
| Microcrystalline, Small, Very | microxln, sml, v |

### Grain Shape

| | |
|---|---|
| Acicular, Angular, Anhedral, | acic, ang, ahd, |
| Bladed, Blocky, | bld, blky |
| Caving, Contorted, Crenulated, | cvg, cntrt, cren, |
| Crinkled, Crumpled, | crnk, crpld, |
| Cuttings, Elongate, Euhedral, | ctgs, elong, euhd, |
| Faceted, Fibrous | fac, fibr, |
| Flaky, Flat, Fragment, Irregular, | flk, fl, frag, irr, |
| Long, Massive, Particle, | lg, mass, par, |
| Platy, Rounded, Splintery, | plty, rndd, splin, |
| Subangular, Subrounded, | sbang, sbrndd, |
| Thick, Thin, Well | thk, thn, wl |

### Sorting

| | |
|---|---|
| Very Well, Well, | v wl, wl, |
| Moderately Well, Poorly, | mod wl, p, |
| Very Poorly, Sorted, Becoming | v p, srt, bcm |

### Luster

| | |
|---|---|
| Coated, Drusey, Earthy, Frosted, | cotd, dru, ea, fros, |
| Glassy, Glossy, Gritty, | glas, glos, gt, |
| Luster, Nacreous, Opaque, Pitted, | lstr, nac, op, pit, |
| Polished, Porcelaneous, | pol, porcel, |
| Resinous, Silky, Silty, Smooth, | rsns, sklky, slty, sm, |
| Sucrosic, Texture, | suc, tex, trnsl, |
| Translucent, Transparent, | trnsl, trnsp, |
| Vitreous, Waxy | vit, wxy |

### Structure

| | |
|---|---|
| Aggregate, Amorphous, Bedded, | agg, amor, bd, |
| Boring, Branching, | bor, brhg, |
| Conchoidal, Concretion, Filled, | conch, conc, fld, |
| Fissile, Foliated, Fracture, | fis, fol, frac, |
| Hackly, Joint, Layer, Lumpy, | hkl, jt, lyr, lmpy, |
| Organic, Parting, Rhomb, | org, ptg, rhb, |
| Striated, Structure,Vein, Vesicular | stri, str, vn, ves, |

### Cement or Matrix

| | |
|---|---|
| Argillaceous, Calcite, | arg, calc, |
| Carbonaceous, Carbonate, Clean, | carb, crbnt, cln, |
| Evaporite, Hematite, Limy, Matrix, | evap, hem, lmy, mtrx, |
| Quartz, Siliceous, Sparry | qtz, sil, spr |

### Visible Porosity

| | |
|---|---|
| No, Trace, Fair, Good, Visible Porosity, Average, | n, tr, fr, gd, vis por, avg, |
| Excellent, Intercrystalline, Integranular, Intraparticle, | ex, intxln, intgran, intpar, |
| Leached, Pin-Point, Solution, Tight, Vuggy, | lchd, p.p., sol, ti, vug, |

### Accessories or Inclusions

| | |
|---|---|
| Abundant, Amount, Biotite, | abd, amt, biot, |
| Brachiopod, Bryozoa, | brach, bry, |
| Chert, Clastic, Common, Feldspar, | cht, clas, com, fspr, |
| Foraminifera | foram, |
| Fossil, Glauconite, Inclusion, | foss, glau, incl, |
| Increasing, Intergrown, | incr, intgn, |
| Lithic, Macrofossil, Magnetite, | lit, macrofos, mag, |
| Material, Micaceous, | mat, mic, |
| Microfossil, Mineral, Minor, | microfos, min, mnr, |
| Numerous, Occasional, | num, occ, |
| Oolite, Ostracod, Pelecypod, | ool, ostr, pelec, |
| Pellet, Plant, Pyrite, Rare, | pel, plt, pyr, r, |
| Scales, Scattered, Shell, | sc, scat, shl, |

### Hydrocarbon Shows

| | |
|---|---|
| Bright, Dead, Extremely, Faint, | brt, dd, extr, fnt, |
| Fluorescence, Irridescent, | fluor, irid, |
| Milky, Residue, Spotty, Stain, | mky, res, spty, stn, |
| Streaming, Uniform, Weak, | stmg, uni, wk |

### Additional Modifiers

| | |
|---|---|
| Approximate, Associated, | apprx, assoc, |
| Concentric, Covered, | cncn, cov, |
| Depauperate, Embedded, | depau, embd, |
| Equivalent, Extremely, | equiv, extr, |
| Frequent, Generally, Heavy, | freq, gen, hvy, |
| Highly, Insoluble, | hi, insl, |

| | |
|---|---|
| Overgrowth, Oxidized, Possible, | ovgth, ox, poss, |
| Prominent, Range, | prom, rng, |
| Replaced, Secondary, Wavy, | rep, sec, wvy, |
| Weathered | wthd |

### Common Words That Require Spelling

Pale, Dull, Poor, Fast, Instant, Crush, Cut, Ring, Slow

## Thin Sections From Drill Cuttings

Preparing thin sections of drill cuttings at the wellsite is a relatively easy process and should be done if the recommended equipment is present and time permits.

### Equipment

- Hot Plate
- Glass Slides
- Thermoplastic Cement
- Glass Grinding Plate (0.25" x 10" x 10")
- Carborundum Loose Grain Abrasive (240, 400, 600 grit)
- Tweezers
- Water Pan

### Procedure

1. Melt cement onto a glass slide using the hot plate, then drop one or more selected cuttings into the cement.
2. Remove the glass slide from the hot plate and allow the cement to cool and harden.
3. Using a wet grinding surface, hone a flat surface on the cuttings. Keep the grinding surface wet by either dipping the slide into water or by spraying water onto the surface.
4. Dry the slide and place it on a hot plate.
5. Using tweezers, turn over the honed surface when the cement melts.
6. Remove from the hot plate and press the cuttings (hones surface down) against the slide as the cement hardens.
7. Hone the other side of the cuttings down to the desired thickness.

When grinding the cuttings (step 7) be careful not to grind the cuttings away. An absolute thickness is not necessary. All that is necessary is to make the cuttings transparent. During the grinding procedure, frequently check the thin section by placing it under the microscope. Generally the cuttings will grind down quickly.

This process is relatively simple to perform and reasonable proficiency can be achieved with a few attempts. The entire process usually takes less than ten minutes. Once the grinding is completed, a cover is not necessary, simply wet the surface while examining under the microscope.

# Conversions

## SI Unit Prefixes

| Multiplication Factor | Prefix | Meaning |
|---|---|---|
| 1,000,000,000,000,000,000 = $10^{18}$ | exa | one quintillion times |
| 1,000,000,000,000,000 = $10^{15}$ | peta | one quadrillion times |
| 1,000,000,000,000 = $10^{12}$ | tera | one trillion times |
| 1,000,000,000 = $10^{9}$ | giga | one billion times |
| 1,000,000 = $10^{6}$ | mega | one million times |
| 1,000 = $10^{3}$ | kilo | one thousand times |
| 100 = $10^{2}$ | hecto | one hundred times |
| 10 = 10 | deka | ten times |
| 0.1 = $10^{-1}$ | deci | one tenth of |
| 0.01 = $10^{-2}$ | centi | one hundredth of |
| 0.001 = $10^{-3}$ | milli | one thousandth of |
| 0.000001 = $10^{-6}$ | micro | one millionth of |
| 0.000000001 = $10^{-9}$ | nano | one billionth of |
| 0.000000000001 = $10^{-12}$ | pico | one trillionth of |
| 0.000000000000001 = $10^{-15}$ | femto | one quadrillionth of |
| 0.000000000000000001 = $10^{-18}$ | atto | one quintillionth of |

| Property | Traditional Unit | Recommended SI Unit | Symbol | Conversion Factor | Example |
|---|---|---|---|---|---|
| Depth | feet | meter | m | 0.3048 | 10,000 ft = 3048 m |
| Hole Diameter | inches | millimeter | mm | 25.4 | 12.25 in = 311 mm |
| Pipe Diameter | inches | millimeter | mm | 25.4 | 4.5 in = 114 mm |
| Bit Size | inches | millimeter | mm | 25.4 | 12.25 in = 311 mm |
| Weight-on-Bit | pounds | newton | N | 4.4 | 20,000 lb = 88,000 N |
| Rotary Speed | rpm | rpm | rpm | 1 | 100 rpm = 100 rpm |
| Nozzle Size | 1/32 inch | millimeter | mm | 0.79 | 10/32 = 7.9 mm |
| Nozzle Velocity | feet/second | meter/second | m/s | 0.3048 | 400 ft/sec = 122 m/s |
| Hydraulic Horsepower | horsepower | kilowatt | kw | 0.746 | 600 hhp = 450 kw |
| Drill Rate | feet/hour | meter/hour | m/h | 0.3048 | 30 ft/hr = 9 m/h |
| Volume | barrels | cubic meter | $m^3$ | 0.159 | 3000 bbl = 477 $m^3$ |
| Liner Size | inches | millimeter | mm | 25.4 | 6.5 in = 165 mm |
| Rod Diameter | inches | millimeter | mm | 25.4 | 2.25 in = 57 mm |
| Stroke Length | inches | millimeter | mm | 25.4 | 16 in = 406 mm |
| Pump Output | bbl/minute<br>gal/minute | cubic m/min<br>cubic m/min | $m^3$/min<br>$m^3$/min | 0.159<br>0.00378 | 8 bbl/min = 1.27 $m^3$/min |
| Pump Pressure | psi | kilopascal | kPa | 6.9 | 2500 psi = 17,300 kPa |
| Annular Velocity | feet/minute | meter/minute | m/min | 0.3048 | 200 ft/min = 61 m/min |
| Slip Velocity | feet/minute | meter/minute | m/min | 0.3048 | 20 ft/min = 6.1 m/min |
| Weight of Drillpipe | pound/foot | kilogram/meter | kg/m | 1.49 | 19.5 lb/ft = 29.1 kg/m |

| Property | Traditional Unit | Recommended "SI" Unit | Symbol | Conversion Factor | Example |
|---|---|---|---|---|---|
| Temperature | º Fahrenheit | º Celsius | ºC | (ºF-32)/1.8 | 80ºF = 27ºC |
| Funnel Viscosity | secs/qt | seconds/liter | s/L | None | |
| Mud Density | lbs/gal | kilogram/ cubic meter | $kg/m^3$ | 120 | 10 lb/gal = 1200 $kg/m^3$ |
| Pressure Gradient | psi/foot | kilopascal/ meter | kPa/m | 22.6 | 0.52 psi/ft = 11.8 kPa/m |
| Hydrostatic Head | psi | kilopascal | kPa | 6.9 | 4000 psi = 27,600 kPa |
| Shear Stress | $lb/100ft^2$ | pascal | Pa | 0.48 | 20 $lb/100ft^2$ = 960 Pa |
| Shear Rate | reciprocal second | reciprocal second | $s^{-1}$ | 1.0 | |
| Plastic Viscosity | centipose | centipose | cP | None | |
| Yield Point | $lb/100ft^2$ | pascal | Pa | 0.48 | 15 $lb/100ft^2$ = 7.2 Pa |
| Gel Strength | $lb/100ft^2$ | pascal | Pa | 0.48 | 3 $lb/100ft^2$ = 1.44 Pa |
| Power Law "n" | | | | None | |
| Power Law "K" | $lb/s^n/100ft^2$ | millipascal $secs^n$/ square cms | $mPa.s^n/cm^2$ | 479 | 1.2 lb $s^n/100ft^2$ = 575 mPa $s^n/cm^2$ |
| API Filtrate | $cm^3$/30 min | $cm^3$/ 30 min | $cm^3$/ 30 min | None | |
| Filter Cake | 1/32 inch | millimeter | mm | 0.8 | 3/32 inch = 2.4 mm |
| Sand Content | Volume % | cubic meter/ cubic meter | $m^3/m^3$ | 0.01 | 10% = 0.1 $m^3/m^3$ |
| Particle Size | micron | micrometer | µm | 1.0 | |
| Ionic Concentration | parts/ million | milligram/liter | mg/L | x s.g. | 100,000 ppm NaCl x 1.070 = 107,070 mg/L |
| Oil/Water Content | Volume % | cubic meter/ cubic meter | $m^3/m^3$ | 0.01 | 10% = 0.1 $m^3/m^3$ |
| Mud Additive Concentration | pound/ barrel | kilogram/ cubic meter | $kg/m^3$ | 2.85 | 10 lb/bbl = 28.5 $kg/m^3$ |

## Table Of Conversions

| | |
|---|---|
| **LENGTH** | |
| inches x 2.5400 = centimeters<br>feet x 0.3048 = meter | centimeters x 0.3937 = inches<br>meter x 3.2814 = feet |
| **VOLUME** | |
| $feet^3$ x 0.0283 = $meter^3$<br>$feet^3$ x 0.1781 = barrels<br>$feet^3$ x 7.4805 = gallons<br>$meter^3$ x 6.28994 = barrels<br>liter x 0.2642 = gallons<br>liter x 11.095 = barrels<br>$centimeters^3$ x 0.06102 = $inches^3$ | $meter^3$ x 35.314 = $feet^3$<br>barrel x 5.6146 = $feet^3$<br>gallon x 0.1337 = $feet^3$<br>barrel x 0.1589 = $meter^3$<br>gallon x 3.7854 = liters<br>barrel x 158.98 = liters<br>$inches^3$ x 16.3871 = $centimeter^3$ |
| **DENSITY** | |
| specific gravity x 8.345 = lb/gal<br>specific gravity x 62.43 = $lb/ft^3$<br>pounds/gallon x 0.11984 = kg/ltr<br>psi/ft x 19.268 = lb/gal<br>lb/gal x 119.9 = $kg/m^3$ | pounds/gallon x 0.11984 = s.g.<br>$pounds/feet^3$ x 0.01600 = s.g.<br>kilogram/liter x 8.34500 = lb/gal<br>lb/gal x 0.05190 = psi/ft<br>$kg/m^3$ x 0.00834 = lb/gal |
| **PRESSURE** | |
| psi x 6.98470 = kPa<br>psi x 14.5038 = bars<br>psi x 14.2233 = $kg/cm^2$ | kPa x 0.1450 = psi<br>bars x 0.06895 = psi<br>$kg/cm^2$ x 0.07031 = psi |
| **PRESSURE GRADIENT** | |
| psi/ft x 22.62 = kPa/m | kPa/m x 0.04421 = psi/ft |
| **MASS** | |
| lb x 0.4536 = kg | kg x 2.2046 = lb |

# Quick-Look Log Evaluation

Quick-look wireline/MWD log evaluation is not a comprehensive analysis of the entire log suite, but an approach that is used at the wellsite to allow the Wellsite Geologist to quality control the logs and to identify potential hydrocarbon-bearing intervals.

There are many industry-wide computer programs that can be used by the Wellsite Geologist to determine the relevant equations and perform the calculation procedures.

Whenever performing any type of log analysis, ensure that you have the wireline/MWD company's “log interpretation” chart book. This will allow the Wellsite Geologist to apply the proper corrections to the curves/log values.

## Indications of Permeable Formations

Several curves can give indications of permeable formations. Since permeability cannot be directly calculated from the logs, these indications will provide the basis of further analysis.

The indications are:

- SP deflection away from the shale baseline (the direction depends on the Rmf/Rw ratio)
- Invasion profile on resistivity logs (Rxo/Rt depends on the Rmf/Rw ratio)
- Low Gamma Ray counts
- Mudcake indications on the Caliper log
- Separation of the Micro-Normal and Micro-Inverse curves

### Lithology Indicators

Determination of lithology, formation tops and the exact depth of formations is best achieved using a combination of wireline, MWD and mud logs. It is always best to use as many logs as possible, because various factors affect individual log traces in different ways.

| | Gamma Ray | Neutron/Density separation* | Resistivity Log invasion profile** | Sonic |
|---|---|---|---|---|
| Sand | Low | +6 pu | Yes | 52.5 - 55.5 µsec/ft |
| Limestone | Low | 0 pu | Yes | 47.5 µsec/ft |
| Dolomite | Low | -12 pu | Yes | 42.5 µsec/ft |
| Shale | High | -6 to -30 pu | No | 50 µsec/ft |
| Anhydrite | Low | $\varphi_b$ = 3.0 g/cc<br>$\varnothing_n$ = -1 pu | No | 50 µsec/ft |
| Salt | Low | $\varphi_b$ = 2.0 g/cc<br>$\varnothing_n$ = 0 pu | No | 67 µsec/ft |
| Coal | | $\varphi_b$ = < 2.0 g/cc<br>$\varnothing_n$ = > 40 pu | No | > 100 µsec/ft |

** Requires $\varphi_b$ scales from 1.95 to 2.95 g/cc and $\varnothing_N$ scales from 45 to -15 pu and that the neutron log is recorded using a limestone matrix*

*** Assumes that Rw ≠ Rmf and no hydrocarbons are present*

## Porosity Estimations

The quickest way to obtain a reasonable porosity estimate is by using the Density and Neutron logs, and for this reason they are usually run together and plotted in Track 3. Density will generally be scaled in g/cc while the Neutron will be scaled in porosity units, using a selected lithology (usually limestone) as the matrix.

### Density/Neutron Porosity

$$\phi_{corr} = \sqrt{\frac{\phi_n^2 + \phi_d^2}{2}}$$

### Density Porosity

If the density log is used alone, porosity can be determined using

$$\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

where:

| | |
|---|---|
| $\rho_{ma}$ | = matrix density (g/cc) |
| $\rho_b$ | = log reading (g/cc) |
| $\rho_f$ | = density of mud filtrate (g/cc) |

| **Common** | $\rho_{ma}$ | $\rho_f$ | |
|---|---|---|---|
| Sandstone | 2.65 | Fresh Water | 1.0 |
| Limy Sands | 2.68 | Salt Water | 1.1 |
| Limestone | 2.71 | | |
| Dolomite | 2.87 | | |

Inaccuracies may occur when taking readings in evaporites or gas bearing formations. The lower density will predict a porosity higher than the actual value.

### Sonic Porosity

Since the sonic/acoustic log is one of the first porosity logs run, porosity can be calculated from the sonic log using:

$$\phi_s = \frac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}$$

where:

| | |
|---|---|
| $\Delta t$ | = log reading (µsec/ft) |
| $\Delta t_{ma}$ | = matrix travel time (µsec/ft) |
| $\Delta t_f$ | = fluid travel time (µ/sec/ft) |

| **Common** | $\Delta t_{ma}$ | $\Delta t_f$ | |
|---|---|---|---|
| Sandstone | 52.5 - 55.5 | Filtrate | 189 |
| Limestone | 47.5 | Oil | 238 |
| Dolomite | 43.5 | | |
| Anhydrite | 50 | | |
| Salt | 67 | | |
| Casing | 57 | | |

In shallow uncompacted sands or those where overpressure is causing under compaction, an abnormally high porosity will be calculated. When this occurs a "compaction correction factor" (1/Cp) is required:

$$Cp = \frac{\Delta t_{sh}}{100}$$

where $\Delta t_{sh}$ is the average travel time in shales seen on the log. If the mud log indicates that hydrocarbons are present in the zone, an additional correction is required ($\phi$ x 0.7 for gas and $\phi$ x 0.9 for oil).

## Rw Estimation

If a clean water-bearing formation can be identified from the logs, several approaches can be used to estimate formation water resistivity (Rw).

One such method is the application of Archies equation, assuming Sw = 100% and the values for "a" and "m" are the same ones used in the water saturation equation:

$$Rwa = \frac{Rt \times \varnothing^m}{a}$$

When calculated over several water-wet intervals, the lowest Rwa value is then assumed to be equal to Rw.

Another method is to use the SP or SSP values:

$$Rw_{eq} = Rmf_{eq} \times \text{antilog}\left(\frac{SSP}{-K}\right)$$

where K = 61 + (0.133 x Tf), Tf is in degrees Fahrenheit.

If micro devices are run, then the ratio method can be used:

$$Rw = \frac{Rmf \times Rt}{Rxo}$$

Rw should be calculated in all clean, water-wet zones. The lowest value obtained will probably be closest to the true Rw, and the highest values will indicate zones of low water saturation. If the Rw values from the different methods disagree, the lowest value will give the most optimistic value for interpretation.

## Sw Estimation

All water saturation methods are based on the standard Archie equation:

$$Sw = \sqrt{\frac{a \times Rw}{\phi^m \times Rt}}$$

| **Common Values for**: | a | m |
|---|---|---|
| Carbonates | 1.0 | 2 |
| Sandstones | 0.81 | 2 |
| Unconsolidated Sands | 0.62 | 2.15 |

Water saturation calculations in Shaly Sands is difficult, and there are many equations/models available to solve the same problem. Shaly Sand analysis is reviewed in the "*Advanced Wireline/MWD Procedures*" manual.

## Shale Estimation

The MWD/wireline Gamma Ray log can be used to calculate the shale content. The equation for the Gamma Ray Index:

$$I_{GR} = \frac{GR - GRmin}{GRmax - GRmin}$$

where GR is the gamma ray reading from the curve, the GRmax is the highest gamma ray reading in a shale, and GRmin is the lowest gamma ray reading in a clean sand.

Once the IGR is found, two equations (based on the age of the sediments) or the logging company's "Shale Volume" chart can be used:

For "older" more consolidated rocks:

$$Vsh = 0.33 \times [2^{(2 \times IGR)} - 1.0]$$

For the younger, unconsolidated Tertiary rocks:

$$Vsh = 0.083 \times [2^{(3.7 \times IGR)} - 1.0]$$

It should be remembered that radioactive minerals will give high values (especially in sands) of shaliness from the Gamma Ray

# Wellsite Safety

## General Safety Practices

The Wellsite Geologist must follow the oil company's specific wellsite safety practices and in addition, ensure that the other personnel at the wellsite are complying with general safety measures. These include:

1. Know and properly use all personal safety equipment (i.e. goggles, steel-toed boots, gloves, clothing, hard hat).
2. Know and properly use all rigsite safety equipment (i.e. fire extinguishers, showers, eyewash fountains, etc.)
3. Know and follow Material Safety Data Sheet (MSDS) regulations
4. Handle all chemical and radioactive substances properly
5. Handle glassware and laboratory equipment properly
6. Be knowledgeable of and comply with all national, state, local and company chemical and hazardous waste disposal procedures.

## Fire Safety

Fires at the wellsite can have disastrous consequences. Though many are commonplace (welding flames, burning garbage, flaring when testing), there are safety aspects which must not be compromised. All fires at the wellsite must be handled with care.

The most common sources of ignition are static electricity, electrical equipment, friction, mechanical sparks, hot surfaces and flames.

There are three classes of combustible materials

| Class | Flash point |
|---|---|
| I | At or above 100°F |
| II | At or above 100°F, but below 140°F |
| III | At or above 140°F |

and four classes of fires:

| Class | Materials Involved |
|---|---|
| A | Routine combustibles such as wood, cloth, paper, rubber and plastic |
| B | All flammable liquids and gases (grease, solvents, etc.) |
| C | Energized electrical equipment and apparatus (hot plates, ovens, etc.) |
| D | Combustible metals (magnesium, potassium, lithium, sodium, etc.) |

### Types of Fire Extinguishers

The five basic types of fire extinguishers are:

| Type | Used in Class of Fire |
|---|---|
| Water | Class A |
| Carbon Dioxide | Class B and C |
| Dry-Powder | Class B and C |
| Met-L-X | Class D |
| Halogenated Hydrocarbon | Class A, B and C |

### General Terminology

**Flashback**: The rapid combustion of heavy vapors of organic compounds which collect in areas distant from their source, and when burning, lead the flames back to their source to cause a large fire or explosion.

**Flash Point**: The lowest temperature at which a compound in an open vessel will give off sufficient vapors to produce a momentary flash of fire when a flame, spark, incandescent wire or other sources of ignition is brought near the surface of the liquid.

**Ignition Temperature**:
The lowest temperature at which the vapor over the surface of a liquid will ignite and continue to burn, if ignited.

**Auto-Ignition Temperature**:
The lowest temperature at which a vapor will ignite spontaneously when mixed with air.

## Material Safety Data Sheets

For every chemical at the wellsite there should be an accompanying Material Safety Data Sheet (MSDS). All chemical manufacturers and importers are required by law to provide the MSDS for each chemical. The Wellsite Geologist must ensure that the service contractors are in compliance with this law. In effect, ensuring that there is an MSDS for each chemical at the wellsite. If a MSDS is not present, the service contractor should acquire one as soon as possible, or risk losing its services on that well. The MSDS has nine specific information sections. The MSDS will:

1. Identify the chemical's manufacturer, their address, emergency telephone number and date prepared.
2. List all hazardous ingredients that make up at least 1% of the mixture and list the threshold limit value (TLV), the permissible exposure limit (PEL), and the Chemical Abstract Service (CAS) number.
3. Identify each substance by its physical properties; odor, appearance, boiling point, etc.
4. Provide information about fire and explosive hazards.
5. Specify the chemical or reactivity properties of each material with regard to possible reactions with other materials.
6. Provide health-hazard information such as effects of overexposure and any necessary emergency or first-aid treatment.
7. Include a section outlining the steps required to clean up a spill and methods of proper waste disposal.
8. List any special protective equipment necessary while working with the material.
9. If necessary, include a section dealing with long-term storage or handling of the material.

### Definition of Terms Found in the MSDS

**LEL or LFL** - Lower explosive limit or lower flammable limit; the lowest concentration of vapor that will produce a fire or flash when an ignition source is available.

**PEL** - Permissible exposure limit; an exposure limit established by OSHA which can be a maximum concentration exposure limit or a time-weighted average.

**TLV** - Threshold limit value; concentration expression for airborne substances which have no adverse effects to most people on a daily basis.

**TLV-TWA** - The short-term exposure limit or maximum concentration for continuous 15-minute exposure period. The exposure episodes must not exceed four per day and must allow at least 60-minutes between exposure periods.

**TLV-C** - The ceiling exposure limit; a concentration that should never be exceeded

**UEL** - Upper exposure limit; concentration of flammable substance that will not support combustion because the vapor is too rich in fuel for that amount of oxygen present.

## Example MSDS For Phenolphthalein And Carbide

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**Trade Name: PHENOLPHTHALEIN, 1% SOLUTION**
**Common Name: PHENOLPHTHALEIN SOLUTION**

**SECTION I**

| | | |
|---|---|---|
| Manufacturer's Name: | ANDERSON LABORATORIES, INC. | |
| Address: | 5901 FITZHUGH AVENUE<br>FORT WORTH, TEXAS 76119 | |
| Emergency Telephone No.: | 800-424-9300 | Date Received: 10/18/91 |
| Information Telephone No.: | 817-457-4474 | Date Prepared: 10/18/91 |
| Preparer: | ED WEBER | |
| Chemical Name: | PHENOLPHTHALEIN SOLUTION | |
| Supplier's Generic Name: | PHENOLPHTHALEIN SOLUTION | |
| Synonyms: | BANCO | |
| Hazard Class: | FLAMMABLE LIQUIDS POISONS | |
| Other Identifying Data: | NA | |

**SECTION II - HAZARDOUS INGREDIENTS/IDENTIFY INFORMATION**

| Chemical Name | OSHA-PEL (ppm) | ACGIH-TLV (ppm) | CAS Number | Percent |
|---|---|---|---|---|
| ETHYL ALCOHOL | 1000 | 1000 | 000064-17-5 | 90.0 |
| METHANOL | 200 | 200 | 000067-56-1 | 4.7 |
| PHENOLPHTHALEIN | NA | NA | 000000-00-0 | 1.0 |
| WATER | NA | NA | 007732-18-5 | 4.3 |

NOTE: If PEL or TLV is followed by the letter M, value is Mg/Cubic Meter

**SECTION III - PHYSICAL/CHEMICAL CHARACTERISTICS**

| | | | |
|---|---|---|---|
| Boiling Point (F): | 78 | Specific Gravity: | NA |
| Vapor Pressure: | 40MM | Melting Point (F): | NA |
| Evaporation Rate: | NA | pH: | NA |
| Vapor Density (Air=1): | NA | Ignition Temperature (F): | NA |
| Solubility in Water: | NA | Physical State: | LIQUID |
| Pure or Mixture: | MIXTURE | | |
| Appearance and Odor: | LIGHT PINK COLORED, CHARACTERISTIC ODOR | | |
| Warning Properties: | | | |
| Other Physical/Chemical Data: | | | |

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**SECTION IV - FIRE AND EXPLOSION HAZARD DATA**

| | |
|---|---|
| Flash Point (F): | 58 F Method: NA |
| Flammability Classification: | WILL IGNITE IF PREHEATED. |
| NFPA Health Hazard Code: | ORDINARY COMBUSTIBLE HAZARDS |
| Flammable Limits in Air-> | LEL: NA_____% UEL: NA_______% |
| Extinguishing Media: | CO2, DRY CHEMICAL |
| Special Fire Fighting Procedures: | ADDITION OF WATER (FOG) WILL AID IN REDUCING BURNING RATES |
| Unusual Fire & Explosion Hazards: | NA |

**SECTION V - REACTIVITY DATA**

| | |
|---|---|
| Stability: | NORMALLY STABLE |
| Incompatibilities: | NA |
| Conditions To Avoid: | OPEN FLAME OR HIGH TEMPERATURES |
| Hazardous Decomposition Products: | NA |
| Hazardous Polymerization: | DO NOT FORM HAZARDOUS POLYMERIZATION PRODUCTS. |
| Other Reactivity Data: | |

**SECTION VI - HEALTH HAZARD DATA**

| | |
|---|---|
| ROUTES OF ENTRY: | |
| HEALTH HAZARDS | |
| Immediate: | NA |
| Long Term: | NA |
| Other Hazards: | |
| Carcinogenicity: | NONE |

SIGNS & SYMPTOMS OF EXPOSURE / EMERGENCY & FIRST-AID PROCEDURES

| | |
|---|---|
| Eye Contact: | NA |
| Skin Contact: | NA |
| Inhaled: | NA |
| Swallowed: | IF SWALLOWED, INDUCE VOMITING BY GIVING SYRUP OF IPECAC OR BY STICKING FINGER DOWN THROAT. REPEAT UNTIL VOMIT FLUID IS CLEAR. |
| Medical Conditions Aggravated By Exposure: | |

**SECTION VII - PRECAUTIONS FOR SAFE HANDLING AND USE**

| | |
|---|---|
| Action If Released or Spilled: | ELIMINATE ALL SOURCES OF IGNITION. SMALL SPILLS SHOULD BE FLUSHED WITH LARGEQUANTITIES OF WATER |
| Waste Disposal Method: | FOLLOW ALL FEDERAL, STATE AND LOCAL REGULATIONS. |

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| | |
|---|---|
| DOT Storage Category: | FLAMMABLE LIQUID SOLUTION D.O.T. NA 1986 |
| Handling/Storage Precautions: | NA |
| Other Precautions: | |

NOTE: Dispose of all wastes in accordance with federal, state, and local regulations.

**SECTION VIII - CONTROL MEASURES**

| | |
|---|---|
| Work/Hygiene Practices: | NA |
| Special Protective Measures for Maintenance Work: | NA |
| Other Controls, Protection: | |

LOCATIONS WHERE THIS PRODUCT MAY BE PRESENT ARE:

| | |
|---|---|
| DEPARTMENT | LOCATION |
| WAREHOUSE | SHELF |
| UNIT | DRAWER |

## DISCLAIMER

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PAGE 1

**Trade Name: CARBIDE, 1 GALLON**
**Common Name: CALCIUM CARBIDE**

**SECTION I**

| | | |
|---|---|---|
| Manufacturer's Name: | BIG THREE INDUSTRIES, INC. | |
| Address: | P.O. BOX 3047 | |
| | HOUSTON, TX 77253 | |
| Emergency Telephone No.: | 713-868-0302 | Date Received: 10/21/91 |
| Information Telephone No.: | Date Prepared: 10/21/91 | |
| Preparer: | ED WEBER | |
| Chemical Name: | CAC2 + CAO | |
| Supplier's Generic Name: | CALCIUM CARBIDE | |
| Synonyms: | CALCIUM DICARBIDE | |
| Hazard Class: | FLAMMABLE SOLIDS | |
| Other Identifying Data: | DANGEROUS WHEN WET | |

**SECTION II - HAZARDOUS INGREDIENTS/IDENTIFY INFORMATION**

| Chemical Name | OSHA-PE (ppm) | ACGIH-TLV (ppm) | CAS Number | Percent |
|---|---|---|---|---|
| CALCIUM CARBIDE | NA | NA | 000075-20-7 | 100 |

NOTE: If PEL or TLV is followed by the letter M, value is Mg/Cubic Meter

**SECTION III - PHYSICAL/CHEMICAL CHARACTERISTICS**

| | | | |
|---|---|---|---|
| Boiling Point (F): | NA | Specific Gravity: | 2.22 |
| Vapor Pressure: | NA | Melting Point (F): | NA |
| Evaporation Rate: | NA | (Butyl Acetate = 1)pH: | NA |
| Vapor Density (Air=1): | NA | Ignition Temperature (F): | NA |
| Solubility in Water: | YES | Physical State: | SOLID |
| Pure or Mixture: | PURE | | |
| Appearance and Odor: | DARK GRAY, ODOR OF ACETYLENE | | |
| Warning Properties: | SMELL | | |
| Other Physical/Chemical Data: | | | |

**SECTION IV - FIRE AND EXPLOSION HAZARD DATA**

| | | | | |
|---|---|---|---|---|
| Flash Point (F): | NA | Method: | OPEN CUP | |
| Flammability Classification: | NOT APPLICABLE | | | |
| NFPA Health Hazard Code: | EXTREME DANGER | | | |
| Flammable Limits in Air-> | LEL: | NA_____% | UEL: | NA_____% |
| Extinguishing Media: | DRY CHEMICAL, CO2, COVER WITH SAND OR LIME | | | |
| Special Fire Fighting Procedures: | CALCIUM BARBIDE IS NON FLAMMABLE UNLESS EXPOSED TO WATER. WATER IS NOT USED TO EXTINGUISH FIRES WHERE CALCIUM CARBIDEIS USED OR STORED. | | | |

PAGE 2

| | |
|---|---|
| Unusual Fire & Explosion Hazards: | WHEN EXPOSED TO MOIST AIR OR WATER, ACETYLENE GAS IS FORMED. ACETYLENE IS LIGHTER THAN AIR AND MAY ACCUMULATE IN OVERHEAD AREAS. ACETYLENE HAS A WIDE EXPLOSION RANGE - 2.5% TO 80% BY VOLUME IN AIR. |

**SECTION V - REACTIVITY DATA**

| | |
|---|---|
| Stability: | NORMALLY STABLE |
| Incompatibilities: | WATER, MOISTURE, MOIST MATERIALS, UNALLOYED COPPER, SILVER, MERCURY. |
| Conditions To Avoid: | CONTACT WITH WATER OR MOIST MATERIALS IN AIRTIGHT CONTAINERS. |
| Hazardous Decomposition Products: | HEAT OF HYDRATED LIME AND ACETYLENE GAS. |
| Hazardous Polymerization: | MAY OCCUR |
| Other Reactivity Data: | |

**SECTION VI - HEALTH HAZARD DATA**

| | |
|---|---|
| ROUTES OF ENTRY: | SKIN, INHALATION. |
| HEALTH HAZARDS | |
| Immediate: | NA |
| Long Term: | PROLONGED CONTACT WITH SKIN MAY CAUSE BURNS OR IRRITATION. |
| Other Hazards: | |
| Carcinogenicity: | NA |

SIGNS & SYMPTOMS OF EXPOSURE / EMERGENCY & FIRST-AID PROCEDURES

| | |
|---|---|
| Eye Contact: | FLUSH THOROUGHLY WITH WATER AND GET IMMEDIATE MEDICAL ATTENTION |
| Skin Contact: | FLUSH THOROUGHLY WITH WATER |
| Inhaled: | REMOVE FROM AREA. |
| Swallowed: | GET IMMEDIATE MEDICAL ATTENTION |
| Medical Conditions Aggravated By Exposure: | |

**SECTION VII - PRECAUTIONS FOR SAFE HANDLING AND USE**

| | |
|---|---|
| Action If Released or Spilled: | SPILLED MATERIAL SHOULD BE SWEPT UP AND PUT IN A WATER TIGHT CONTAINER |
| Waste Disposal Method: | MAY BE SALVAGED FOR NORMAL USE. MAY BE PLACED IN AN ACETYLENE PLANT WASTE LAGOON OR RETURED TO MANUFACTURER. |
| DOT Storage Category: | FLAMMABLE SOLID |
| Handling/Storage Precautions: | STORE IN A COOL DRY AREA. KEEP IN A WATER TIGHT CONTAINER UNTIL READY FOR USE. |
| Other Precautions: | |

NOTE: Dispose of all wastes in accordance with federal, state, and local regulations.

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**SECTION VIII - CONTROL MEASURES**

| | |
|---|---|
| Work/Hygiene Practices: | WASH HANDS AFTER CONTACT. |
| Special Protective Measures for Maintenance Work | FILTER MASK, WORK GLOVES, SAFETY GLASSES |
| Other Controls, Protection: | |

LOCATIONS WHERE THIS PRODUCT MAY BE PRESENT ARE:

| DEPARTMENT | LOCATION |
|---|---|
| WAREHOUSE | SHELF |
| UNIT | IN A DRY AREA |

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