Drill-Stem Testing (DST)

Conference Paper · January 2015

1 author:

Azad Adeeb
University of Kurdistan – Hawler

Drill-Stem Testing (DST)

Prepared by: Azad Adeeb Noori

Supervised by: Dr. Khosraw Bazrafshan

Petroleum Geology

University of Kurdistan- Hewler

Abstract

One of the most important stages of completing a well is discussed in this report which is the Drill-Stem Testing (DST). This report discusses three main aspects of this technique, it indicates the detailed function of each component of the tool assembly. Then it discusses the required decisions to be made to perform a test. Its main focuses would be on the procedure of the test and highly emphasizes on the best interpretation of DST pressure charts.

Introduction

Drill-stem testing (DST) is one of the most important completion techniques. It is a type of temporary completion that is used to evaluate the formation and inspect a reservoir's properties. According to (Ammann, 1960), the measurement of the reservoir properties by the DST can be delivered directly or indirectly. Direct measurements means that the data are recorded when the tool assembly was down in the hole. Those measurements include, the Static Reservoir Pressure, flow rate measurement, reservoir depletion if took place during the test, and obtaining a recovery sample of the formation fluids. However, the indirect measurement or empirical measurements are those parameters that yield from the use of equations and it includes, most importantly the productivity index (PI), effective permeability of the formation to the fluid flow, formation transmissibility, skin factor, drainage radius of the investigation test, and detection of reservoir anomalies (such as barriers, fluid contacts, permeability changes or layered zones). As (Black, 1956) states that special completion equipment are required to perform the test, some of them are compulsory while others are auxiliary depending on the well conditions and the test requirements. The following section discusses the tools that make up the DST tool assembly.

Equipment of the Drill-Stem Test tool

The drill-stem tool has four basic or compulsory components that should exist in every tool assembly made by any service company. These four components are: the pressure recorders, the test valves, the hydraulic by-pass or equalizing valves and the packers. A general diagram of the DST tool is shown below in figure (1):

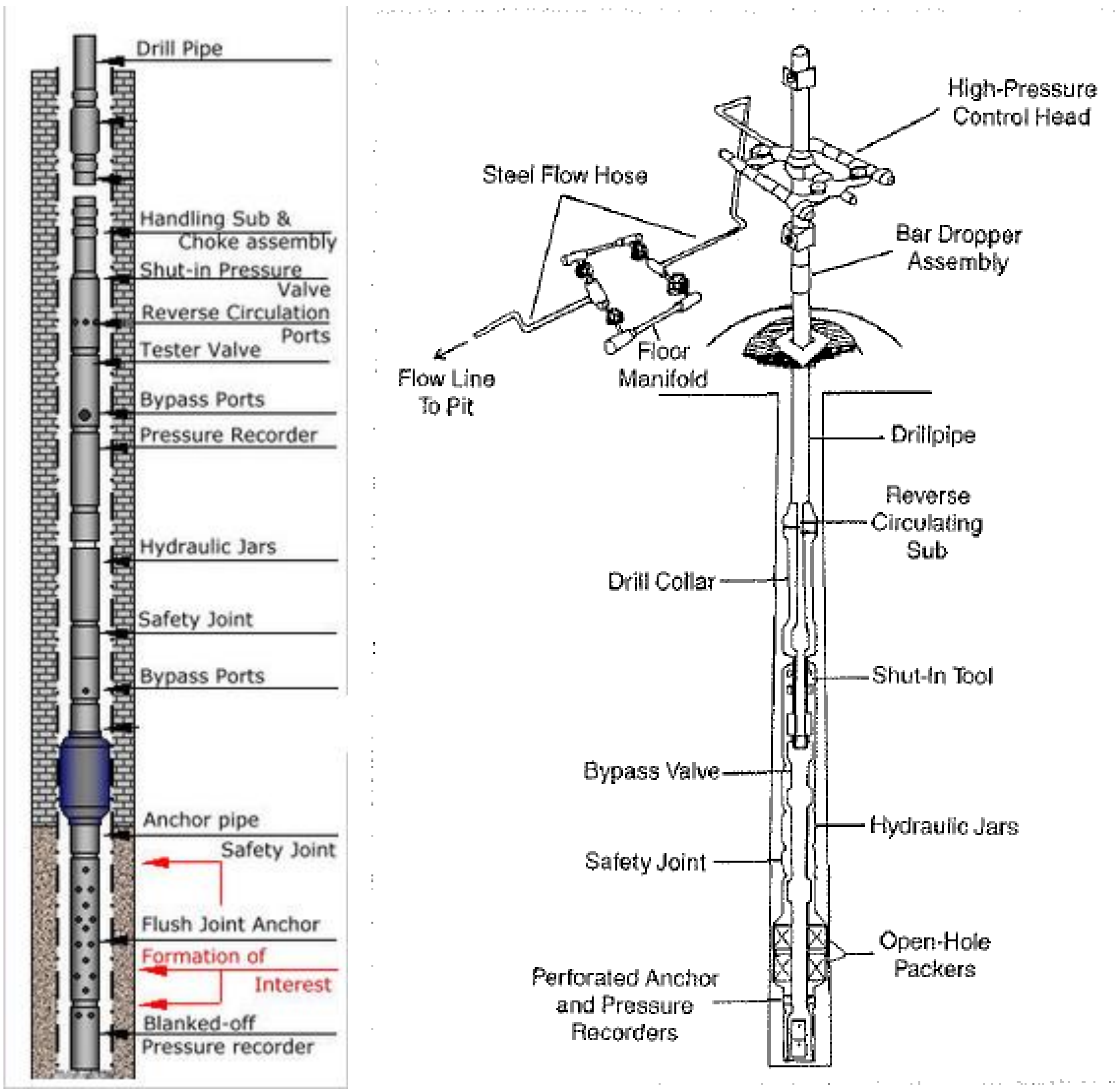

Figure (1): Illustrates the components of the Drill-Stem Test tool including both surface equipment and down-hole tool.

1. The Pressure recorders (the Brain of the DST tool assembly):

The DST tool is almost useless without the existence of pressure recorders. According to (Dolan, 1957) the pressure recorders are built in a number of pressure capacities as well as clock speeds. The pressure recorders used in the DST tool are usually sensitive for low pressure gauges as much as ½ psig and for high pressure gauges as much as two thirds of the maximum pressure of the well.

2. The Test valve:

This valve has a major role in the drill-stem test. It is placed in the upper section of the DST tool above the hydraulic by-pass valve. According to (Black, 1956), one of its main functions is to provide a passage for the fluids to flow into the drill pipe when the packer is set at the annulus. Second, it prevents the drilling mud to enter the empty drill pipe while running in the borehole. It also assists in the prevention of drilling mud entrance to the drill pipe while pulling out the DST tool assembly and aids in the conservation of the recovered reservoir fluids to the surface. Figure (2) below shows the test valve:

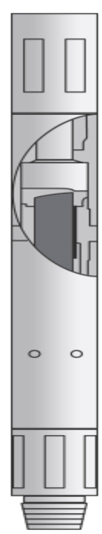

Figure (2): Test valve.

3. The hydraulic by-pass valve:

The hydraulic by-pass valve has a role in relieving the pressure in the borehole. It provides an additional space for the drilling mud to pass around the packer while running in or pulling out of the borehole. It allows the drilling mud under hydrostatics pressure to flow downward through the packer mandrel at the end period of the test into the holes below the packer. This certain function provides the equalization of pressures around the packer causing it to be retrieved easily to the surface.

4. The Packers:

The packers used in the DST tool are temporary, which means that they can be retrieved to the surface unlike other types of permanent packers which stay in the well. According to (Petrowiki, 2014) packers are of different shapes and are made of rubber-like materials that can be compressed to expand against the borehole wall. Their main functions are to seal the annulus space and prevent the down-hole movement of the drilling stem. This sealing mechanism prevents the vertical flow of the fluids in that section of the well. Packers very often improve the production rate of the well by directing the formation fluids to one way passage rather than going into the annulus space. According to (Black, 1956), packers are usually set above the assigned perforation zone to prevent the formation fluids from flowing through the annulus space to the surface. The packers are set in the hole by rotation of the drill pipe controlled by the driller at the surface. Figure (3) below shows some types of packers:

Figure (3): Shows different types of packers.

In addition to the basic component of the DST tool there are other auxiliary components that most of the modern DST assemblies are composed of, which include the following:

1. The Shut-in pressure valve:

This specialized valve is located below the reverse circulating valve of the DST tool assembly. Bredehoeft (1965) states that shut-in valves have a role in the shut-in periods within the test, meaning the initial shut-in and the final shut-in periods. One of its functions is to permit the test valve to be closed at the end of the flow period with reduced prospect of unseating the packer or letting the pressure equalize around the packer through the by-pass valve. It also helps in retaining the formation recovered liquids.

2. The Disk valve:

This valve aids in the prevention of the drilling mud entrance into the drilling pipe while running in hole. Its second function is to allow the packer to be set firmly and the tester valve to be opened, before the tool is opened the disk valve rupture by the dropped go-devil from the surface. A sample of the disk valve is shown in the figure (4) below:

Figure (4): Disk valve.

3. The Reverse Circulating valve:

The importance of this valve is that it allows the recovered fluid to be pumped out of the drill pipe by reverse circulation into surface tanks. It also provides safe operation for the test by conditioning the mud in the annulus. A diagram of the circulating valve is shown below in figure (5):

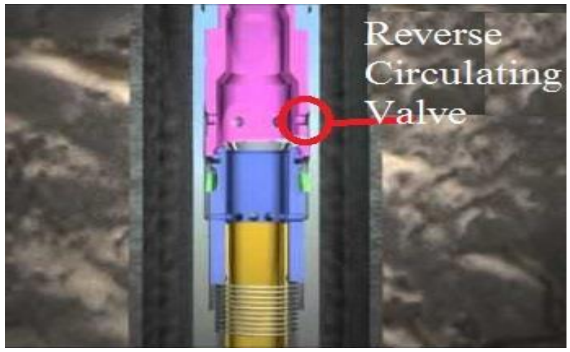

Figure (5): Reverse Circulating Valve.

4. The Jar:

The type of jar used in the DST tool is a hydraulic jar that is designed to provide impact blows to set free the stuck packer or DST tool whenever possible. A sample of the hydraulic jar is shown below in figure (6):

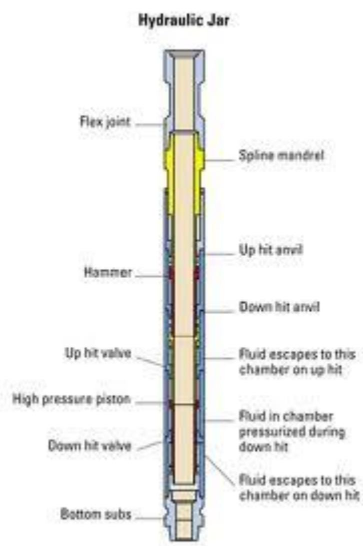

Figure (6): Hydraulic Jar

5. The Safety joint:

This tool is used to unscrew and retrieve the DST tool when either the anchor or the packer is stuck in hole. It allows safe recovery of pressure data to the surface as well as fluid samples. A sample of the safety valve is shown in the figure (7) below:

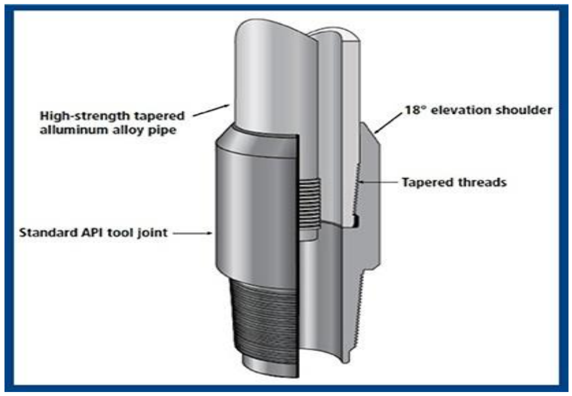

Figure (7): Safety joint.

6. The Anchor shoe (Bullnose jetting nozzles):

The anchor shoe is the head of the DST tool, placed in the lower end of the tool which enters the wellbore first. It is made of hard material to absorb the damage caused by restricting material in the well. According to (Hyne, 2012) anchor shoe head contains nozzles or openings that decrease the buoyancy of the fluids in the well as well as breaking the surface tension of the fluids. Another important function of the anchor shoe is that it anchors the DST tool in the bottom of the well and holds it weight. The bullnose figure is shown below, in figure (8):

Figure (8): Anchor shoe or Bullnose jetting nozzles.

7. The Bottom Hole Choke:

The Bottom Hole Choke is a short sub that can be located below the packer and above the perforated pipe. It aids in the restriction of the flow down hole. It holds some backpressure under the packer and reduces the hydrostatic pressure on it.

8. Perforated pipe:

According to (Raymond, 2006) the perforated pipe is located above the anchor shoe and its function is to shoot perforating bullets into the formation, as the go-devil is sent from the surface to start the perforation. A diagram of the perforation process is shown below:

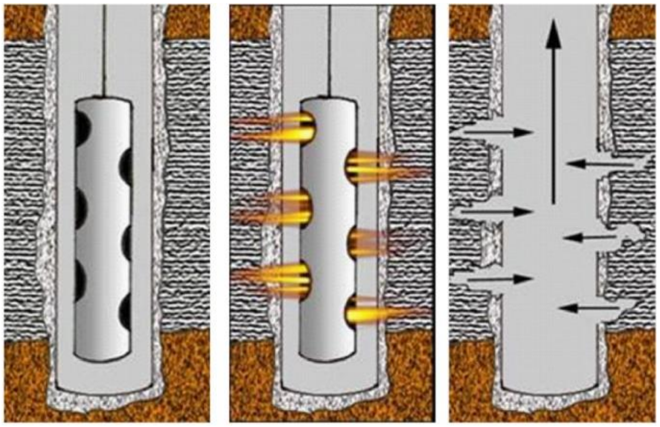

Diagram (1): Shows perforation of the formation.

9. The Surface Control Head (Christmas Tree):

This surface assembly controls the fluid flow from the drill pipe to the surface through a set of valves and chokes. A diagram of the Christmas tree is shown in the figure (9) below:

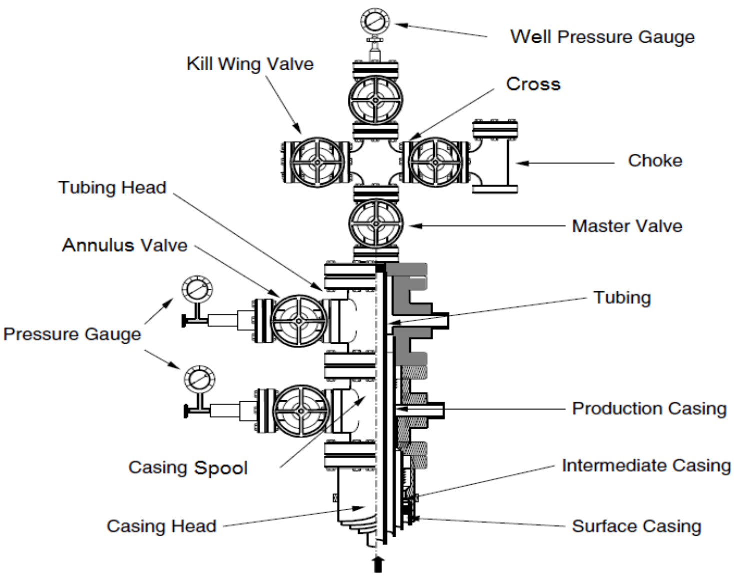

Figure (9): Christmas tree.

Designing the DST plan

In order to insure that the desired information are delivered by the DST test detailed considerations must be given to a number of factors. Taking in consideration the following factors increase the probability of success of the test:

1. **The amount of hole to test:**

   Raymond (2006) states that it is needed to know at which depth or total depth (TD) the test is going to be executed and what type of formation is included, which of course most of these data have been collected while logging and other geophysical techniques.

2. **Packer size selection and assigning the location of the packer seal:**

   Determining the suitable size of the packer and its seal location has a great effect on the success of the DST test. According to (Black, 1956), it should be decided accurately which type of packer is required that totally matches the well conditions, whether the well is open-hole or cased hole, or whether the formation for inspection is a sandstone or limestone, etc. The location of the packer seals are assigned by the help of caliper logs which provide an approximate radius of the borehole and the least clearance between the well wall and the packer seal. As the packer size selection depends on the type of formation, so the packer seal does.

3. **Selecting the suitable top and bottom hole chokes:**

   The selection of the top and bottom-hole chokes is made by considering the safety point first. The right use of the top and bottom chokes prevent choke plugging or fluid flow restriction. In general, the bottom choke is chosen to be smaller in diameter than that of the top choke to control the amount of flow to the surface.

4. **Estimation of the time required to perform the test:**

   The pre-decision of the length of the test is a vital factor in the procedure. Grant (1995) states that through this step, the time required for setting the packer, opening the test valve, the initial flow, initial shut-in, final flow and final shut-in are all assigned their specific periods throughout the process.

5. **Selection of pressure gauges and manner of displacement in the tool:**

   As it has been mentioned before the pressure gauges are considered as the brain of the DST tool, therefore as Christie (n.d) states that to perform the test at least two subsurface pressure gauges are needed to run the tool in the well as one of them is placed inside the anchor shoe for it to record the pressures below the bottom hole choke, while the other is placed outside the anchor shoe to record the pressures exerted by the formation fluids or the drilling mud. The pressure recorders should be chosen correctly so that they are able to record pressure higher than the maximum pressure of the well for obtaining more accurate results.

6. **Assigning the location of circulating valve, jars and safety joints:**

   The circulation valve is usually placed above the test valve, this choice is made for it will permit the retention of uncontaminated formation liquid samples. The jars are usually placed above and as near as possible to the packer to set it free. The safety joints are placed in a location below the pressure recorders so that the data won't be lost in case of stuck anchor or packer.

7. **Considering the use of water or gas cushion:**

   The use of water or gas cushion should be considered in order to prevent the abrupt flash release of pressure from thousands (psia) of drilling mud pressure to atmospheric pressure. According to (Timmerman, 1972) undesired flash release causes damage to the formation of the well in the form of caving of the wellbore wall. It may also cause the plugging of the anchor perforations or even the bottom-hole choke. Water cushions are usually placed in the drill pipe to reduce the pressure differentials that occur across the wall of the borehole and the packer as the tool is opened.

Executing DST test and interpreting DST pressure chart

The simplest way to describe the process of Drill-Stem Testing is to present a typical DST pressure chart of an open hole, see figure (10) and describe each segment of it. When all the factors for performing a DST are taken in consideration as mentioned in the previous section, the plan for the DST is ready to run. However, before running the tool into the well, the tester inserts the test chart into the recorder and draws the baseline which indicates (0 psig), the blue line in the figure (10). The well should be conditioned and filled with drilling mud. The driller pulls out the whole drilling string out to the surface to replace the drilling bit with the DST tool, then he enters the whole string back again into the well, stand by stand. According to Bredehoeft (1965), the DST test is performed as follows:

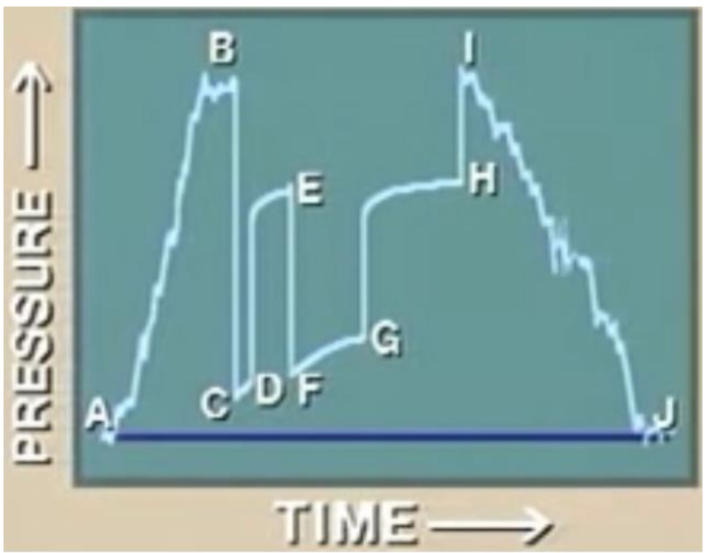

Figure (10): DST pressure chart

- The initial phase of the test is observed in segment (A to B) as shown in the chart above. As the tool runs down the hole the hydraulic by-pass valve is left open because the packer has limited clearance between the casing and the wellbore. The open by-pass valve allows the drilling mud to go up the drilling pipe and up to the surface, this action is meant to lower the pressure surges created as the tool runs down the hole. The pressure gauges start to record an increase in the pressure. This increment is due to the buildup in the hydrostatic pressure of the drilling mud column present inside the well. It can be observed that the pressure curve is not smooth because of pressure surges which occur even when the by-pass valve is open. The pressure surges are caused by the addition of connections to the drilling string. Another reason for that is the existence of tight spots encountered in the hole as the well wall is not straight downwards. Sometimes pressure surges occur due to addition of water cushion or repair surface equipment. All of these noises are recorded by the pressure gauges as they run down the hole.

- After the perforated section pipe has reached the test interval or total depth (TD), the surface equipment is connected to the drill pipe during this time the pressure stabilizes at point (B). The pressure surges end and the initial hydrostatic pressure is recorded relatively at the point where there is flat pressure values. The driller then slags off the brakes creating a weight on the DST tool causing the packer to expand. The packer seals off the area between the interval of interest as well as the gage from the column of mud above the packer. Once the packer is set the driller rotates the drilling stem causing the tester valve to open momentarily for few minutes (from B to C). The initial flow takes place from (C to D) this period lasts from 5 to 10 minutes. The initial flow pressure recorded at point (C) is nearly atmospheric unless a water cushion is placed in the drill pipe. This action allows the pressurized formation fluid and drilling mud to flow into the tool and up to the surface.
- The test valve is then closed and the initial shut-in period takes place with a duration of 30-60 minutes from points (D to E). Surface indication of the flow are observed and the pressure builds up reaching the Static Reservoir Pressure at point (E).
- The test tool is opened again from (E to F) and the final flow period occurs from (F to G). The shape of the buildup will depend on the properties of the formation and the fluids. The duration of this period takes from three hours to maybe days depending on the owner requirement.
- At the end of the final flow period the test valve is again shut-in at point (G) and the final buildup period takes place from (G to H). To remove the DST tool the driller first opens the reverse circulating valve. It is opened hydraulically by pumping the drilling mud down the annulus, with the valve open the drilling mud circulates down the annulus and the up the drilling pipe to the surface. The drilling fluid kills the well by keeping the formation fluids under control. Then the packer is released at point (H) either by rotating the drilling string or by the use of hydraulic jar. The hydrostatic pressure of the mud column is felt

back again by the pressure recorder at point (I), then the tool will retrieve from the hole from points (I to J).

Conclusion

The integration between tests results and data are compulsory for completing a well. Going blindly into completion of a well without performing the drill-stem testing is a great loss. This report has discussed the importance of the DST. It highlighted the main components that makes up the DST tool each with their own particular function. It also discussed the best design for the DST and how it is executed. The report came up to conclude that the ability of a well to be completed successfully is to correctly interpret the DST pressure chart, where by the most important parameter is obtained from it, the static reservoir pressure, knowing this value and other parameters will aid in further development of the well.

References

1) C. B. Ammann (1960). *Case Histories of Analyses of Characteristics of Reservoir Rock from Drill-Stem Tests*. Society of Petroleum Engineers. doi:10.2118/1336-G
2) E.H. Timmerman & H.K. Van Poolen (1972). *Practical Use of Drill-Stem Tests*. The Journal of Canadian Petroleum Technology, Montreal, (pp. 32-40).
3) J.D. Bredehoeft, (1965). *The Drill-Stem test: The Petroleum Industry's Deep-well Pumping Tests*. Published by the U.S. Geological Survey.
4) J.P. Dolan & et.al (1957). *Special Application of Drill-Stem Test Pressure Data*. Petroleum Transactions, AIME, vol. 210, (pp. 318-324).
5) M. S. Raymond & W.L. Leffler, (2006). *Oil and Gas Production in Nontechnical Language.* Penn Well Corporation
6) N.J. Hyne (2012). *Nontechnical Guide of Petroleum Geology, Exploration, Drilling and Production*. Third Edition, Penn Well Corporation.
7) R. Grant & H. Gill (1995). *How to Increase the Reliability of your Open Hole Drill-Stem Test Analyses.* The petroleum society of CIM.
8) R.S. Christie (n.d). *Use of Recording Pressure Gages in Drill-Stem Tests*. Drilling Practice, (pp. 8-12).
9) W. M. Black (1956). *A Review of Drill-Stem Testing Techniques and Analysis*. Society of Petroleum Engineers. doi:10.2118/589-G

Online sources

1) http://petrowiki.org/Packers
2) http://glossary.oilfield.slb.com
3) United States Department of Labor: https://www.osha.gov/SLTC/etools/oilandgas/well_completion/well_completion.html