INTRODUCTION

Cementing is the most important non-drilling function performed by the Drilling Foreman. Poor cementing techniques can cause countless drilling problems if the bottom joint of surface pipe is lost. It can also cause costly remedial operations or loss of hole. A bad cement job can make an otherwise sound investment a disaster. Loss of control means loss of reserves and reduces the potential of secondary recovery operations.

Cement has three functions. The first and most important function of the cement slurry is to carry all of the worlds trash (we call it additives) a mile or two under the ground and dispose of it. The cement must also be capable of supporting the casing. And finally, the cement must adequately isolate the intervals of interest. All design considerations should be directed at these functions. The Drilling Foreman should be concerned with accomplishing these functions as simply and economically as possible.

During primary cementing, the same problems encountered in a vertical well are encountered in a directional well. But a directional well can encounter a few more problems than a vertical well. These problems include the formation of a cuttings bed on the low side of the hole, solids settling in the cement, and the formation of a free water channel on the high side of the hole.

MANUFACTURE OF CEMENTS

Cements are made from limestone (or other high calcium carbonate materials) and clay or shale. Some iron and aluminum oxides may be added if not present in sufficient quantity in the clay or shale. These materials are finely ground and mixed, then heated to 2600-2800° F in a rotary kiln. The resulting clinker is then ground with a controlled amount of gypsum to form Portland Cement.

All cements are manufactured in essentially the same way from the same ingredients, but in different proportions. The water requirement of each type of cement varies with the fineness of grind or surface area. High early strength cements have high surface area (fine grind). Retarded cements have low surface area, and Portland cements have a surface area slightly higher than retarded.
### Table 1  
*Typical composition of portland cement compounds.*

<table>
<thead>
<tr>
<th>API CLASS</th>
<th>C₃S</th>
<th>C₂S</th>
<th>C₃A</th>
<th>C₄AF</th>
<th>FINENESS (sq cm/gram)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A  Portland</td>
<td>53</td>
<td>24</td>
<td>8</td>
<td>8</td>
<td>1500 - 1900</td>
</tr>
<tr>
<td>B  Portland</td>
<td>47</td>
<td>32</td>
<td>3</td>
<td>12</td>
<td>1500 - 1900</td>
</tr>
<tr>
<td>C  Accelerated</td>
<td>58</td>
<td>16</td>
<td>8</td>
<td>8</td>
<td>2000 - 2400</td>
</tr>
<tr>
<td>D &amp; E Retarded</td>
<td>26</td>
<td>54</td>
<td>2</td>
<td>12</td>
<td>1100 - 1500</td>
</tr>
<tr>
<td>G  Basic</td>
<td>52</td>
<td>32</td>
<td>3</td>
<td>12</td>
<td>1400 - 1600</td>
</tr>
<tr>
<td>H  Basic</td>
<td>52</td>
<td>32</td>
<td>3</td>
<td>12</td>
<td>1400 - 1600</td>
</tr>
</tbody>
</table>

*Plus gypsum, free lime, alkali (Na + Mg)*

API classes A through E are becoming obsolete. The trend is toward a basic cement - Class G or H - tailored with additives to meet particular requirements. Basic cements are compatible with additives and a tailored slurry is slightly cheaper than a neat slurry. Standardization to a basic slurry reduces manufacturing and packaging costs which will tend to keep the price of cementing at a minimum. This is good for the industry and the Drilling Engineer because it makes us know more about the products added to the basic cement.

### GENERAL PROPERTIES OF OIL WELL CEMENTS

Cements have various properties that are important to drilling personnel. The properties are:

1. Viscosity,
2. Thickening time,
3. Density,
4. Fluid loss,
5. Free water,
6. Compressive strength and
7. Yield

**Viscosity**

The viscosity of cement is normally 40-75 funnel seconds. Cements are non-Newtonian fluids and are shear thinning. The cement gets thinner as the shear rate (velocity) increases. The Bingham Plastic and the Power Law Models can be used to describe the viscosity of cement at various shear rates; however, the Power Law Model is more accurate.
Viscosity is important when considering displacement mechanics. A low viscosity cement will have better displacement properties at higher flow rates, while a high viscosity cement may have better displacement properties at lower flow rates. In directional wells, solids separation is a concern. After the cement is placed and before it takes its initial set, the solids in the cement can settle toward the low side of the hole. Settling will leave a lower density cement on the high side of the hole which is not desirable. The viscosity and gel strengths of the cement will determine the likelihood of solids settling, and the degree to which it occurs.

Viscosity is controlled by the amount of water added to the cement. Only 25% water by weight of cement is required for hydration, but more water is added to provide for pumpability. Dispersants lower the yield point of cement slurries reducing friction and allowing turbulence to occur at lower pump rates. Using dispersants allows the cement to be mixed with less water yielding higher densities.

**Thickening Time**

The thickening time of cement can vary anywhere from 20 minutes to days depending upon the pressure, temperature, additives and how the cement is mixed. Published values for thickening time are based on the API Standards for Temperature. Thickening time tests should be run for actual well conditions when those conditions vary from the API standards.

Thickening time test are run in a pressurized consistometer. It should be remembered that a pressurized metal container does not always simulate downhole conditions. If some of the mix water is lost to a permeable formation through filtration, then the pumping time can be less than anticipated. Interruptions in pumping the cement can also cause a reduction in the thickening time. If the cement is allowed to sit for a while, the thickening time values are no longer applicable. The actual mix water from the location should be used in the thickening time tests whenever possible.

Planned thickening times should allow ample time to place the cement plus enough time should any unexpected problems occur. However, thickening times should not be excessive. Waiting on cement (WOC) to set before resuming drilling operations can be costly especially in high day rate operations. Excessive thickening time can also allow settling and separation of slurry components, loss of hydrostatic head resulting in gas cutting, and formation of free water pockets.
Thickening times can be reduced by adding accelerators such as calcium chloride. The temperature of the mix water is also important particularly with accelerated cements. Figure 1 shows the effect of temperature on thickening time. The thickening time for Class A with two percent calcium chloride is ten hours at 60 degrees but reduces to 4 hours at 80 degrees.

![Figure 1: Effect of temperature on thickening time](image)

Increasing pressure will shorten thickening time although its effects are less pronounce than temperature.

Retarders are added to cement to increase thickening time. Usually, extenders added to the cement to reduce density will increase thickening time. Adding more mix water will increase thickening time with unretarded cements but may not be the case with retarded cements. The additional water can dilute the retarder concentration and therefore its effectiveness.

**Density**

The density of cement can vary from less than 8.33 ppg for foamed cement to as much as 20 ppg for densified slurries. Slurry densities need to be varied to prevent lost circulation or to control abnormal formation pressures.
Normal densities for API cements are shown in Table 2. The density can be varied by altering the water content; however, care should be taken to avoid excess water. Too much water will increase thickening time and reduce the strength of the cement.

Table 2 Normal water requirements and densities for neat API slurries from Halliburton Red Book.

<table>
<thead>
<tr>
<th>API CLASS</th>
<th>WATER (gals/sk)</th>
<th>DENSITY (ppg)</th>
<th>YIELD (ft³/sk)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>5.2</td>
<td>15.6</td>
<td>1.18</td>
</tr>
<tr>
<td>B</td>
<td>5.2</td>
<td>15.6</td>
<td>1.18</td>
</tr>
<tr>
<td>C</td>
<td>6.3</td>
<td>14.8</td>
<td>1.32</td>
</tr>
<tr>
<td>D</td>
<td>4.3</td>
<td>16.4</td>
<td>1.06</td>
</tr>
<tr>
<td>E</td>
<td>4.3</td>
<td>16.4</td>
<td>1.06</td>
</tr>
<tr>
<td>G</td>
<td>5.0</td>
<td>15.8</td>
<td>1.15</td>
</tr>
<tr>
<td>H</td>
<td>4.3</td>
<td>16.4</td>
<td>1.06</td>
</tr>
</tbody>
</table>

The density can also be decreased by adding extenders such as pozzolans and bentonite. The extenders require more mix water. Of course, density can be increased by adding weight material such as barite and hematite.

**Yield**

The yield is the volume of cement mixture created per sack of initial cement. The yield can vary significantly depending upon the additives. Slurry yields can be as little as 0.90 ft³ per sack for densified cement to 4.70 ft³ per sack for a pozzolan, cement and bentonite mix. Table 2 shows the yields for various API cements when the normal mix water is used.

**Fluid Loss**

The API fluid loss test is conducted at 100 psi differential through a 325 mesh screen. The fluid loss for Class A neat cement will exceed 1000 ml. The API well simulation test is run at various elevated temperatures and a pressure differential of 1000 psi through a 325 mesh screen. The testing procedures can be found in API Spec 10. Whenever fluid loss tests are reported, the temperature and differential pressure should be included.

Usually, bentonite or high molecular weight polymers are added to the cement to reduce the fluid loss. The fluid loss additives are temperature dependent and will lose some effectiveness at higher temperatures. Some polymers will even break down at high temperatures.
Reported optimum values for fluid loss varies considerably using the API well simulation test at bottomhole circulating temperature. For a typical casing job, recommended fluid loss values range from a maximum of 100 ml to no control. The recommended API fluid loss ranges from 50 to 250 ml for liners and 50 to 200 ml for squeeze cementing. The literature also recommends that the fluid loss be kept below 150 ml when annular gas flow is a problem. For most applications, a fluid loss of 200 ml is adequate.

**Free Water**

Free water is caused by the separation of the mix water and cement solids. All neat cement will have some free water which can contribute to annular gas flows. In deviated and horizontal wells, the separated mix water will migrate to the high side of the hole and cause a channel. In directional wells or wells with annular gas flow problems, the free water content should be equal to zero. Recommended free water content for most vertical casing jobs is less than one percent. Addition of fluid loss additives or 0.1% to 0.2% bentonite will reduce the free water content to near zero.

**Compressive Strength**

When cement sets, it develops a compressive strength over time. The compressive strength it develops is a function of time, temperature, and pressure. Above 3000 psi, there is very little change in compressive strength as the pressure increases. All API compressive strength tests are run at 3000 psi when the depth is below 4000 feet since there is little change in the expected compressive strength. The API Spec 10 has pressure and temperature schedules for compressive strength tests based upon depth and anticipated temperature gradient.

Neat cements will attain the highest compressive strengths. Usually, the compressive strength will be near the maximum within 72 hours. Extenders and using more mix water will decrease the ultimate compressive strength. By the same token, densifying a slurry by using the minimum mix water will increase the ultimate compressive strength. At the same temperature, accelerated cements will attain a higher compressive strength quicker than neat cements and retarded cements.

For most oil field applications, a compressive strength of 500 psi is sufficient. A lot of filler cements have compressive strengths of 500 psi with relatively low densities and higher yields. Filler
cements are less expensive than neat slurries. Typically, neat cement is placed across the producing formations and behind the shoe joint. Filler cement is used to fill the remainder of the annular space that requires cement.

All compressive strength tests should be run by the service company prior to the cementing job. In critical situations, the actual cement composition and mix water should be used at simulated downhole conditions to determine compressive strength. In development areas, compressive strength can be spot checked where the same cementing mixture is being used on similar wells. There is no need to run lab tests for each well. In the field, dry cement samples should be collected in the advent a cementing problem occurs. Lab tests with the dry samples can be used to investigate the problem.

At high temperatures, cement can suffer from strength retrogression which is a loss in compressive strength with time. It has been reported that above 230°F there is a pronounced decrease in compressive strength and increase in permeability of many commonly used cementing materials. In general, additives which are not chemically reactive with the cement and which require a high water to cement ratio produce a cement of poor temperature stability. (Bentonite is probably the worst offender and should not be used in any composition in excess of 4% by weight of the cement when temperatures are expected to exceed 230°F.)

Addition of 35 to 40 percent silica flour will inhibit strength retrogression. Table 3 shows the increased strength of Class "B" and 50-50 Poz with 30 and 40 percent silica flour. Neat cements without silica flour would have compressive strengths less than 1000 psi depending upon the bottomhole temperature. Silica mix with portland cement can be used to temperatures around 750°F. As with any critical cementing operation, the properties of the proposed cement mixture should be checked in the lab at downhole conditions. For very high temperatures, strength retrogression should be added to the list of properties to check.
Table 3  Effects of temperature on compressive strength.

<table>
<thead>
<tr>
<th>I.E.</th>
<th>SILICA FLOUR (%)</th>
<th>CURED 7 DAYS (°F)</th>
<th>HEATED 7 DAYS (°F)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>80</td>
<td>100</td>
</tr>
<tr>
<td>Class &quot;B&quot;</td>
<td>30</td>
<td>1400</td>
<td>1985</td>
</tr>
<tr>
<td>Class &quot;B&quot;</td>
<td>40</td>
<td>1215</td>
<td>1810</td>
</tr>
<tr>
<td>POZ</td>
<td>30</td>
<td>560</td>
<td>1225</td>
</tr>
<tr>
<td>POZ</td>
<td>40</td>
<td>775</td>
<td>1240</td>
</tr>
</tbody>
</table>

Table 4 shows how the compressive strength will change with addition of silica flour for class G cement. The samples were cured at 440°F for three and seven days, then cured at 725°F for 3 days.

Table 4  Effects of temperature on class G cement with silica flour.

<table>
<thead>
<tr>
<th>SILICA</th>
<th>COMPRESSION STRENGTH (3 days)</th>
<th>COMPRESSION STRENGTH (7 days)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>545</td>
<td>425</td>
</tr>
<tr>
<td>40</td>
<td>11,025</td>
<td>10,010</td>
</tr>
</tbody>
</table>

CEMENT ADDITIVES

Additives are used to tailor cement to a specific application. Additives are available to adjust: density, thickening time, viscosity, control filtration, cost per unit volume, bridging for lost circulation, and special applications.

Additives should not be used indiscriminately, because an additive usually affects more than one physical property of the cement. Adding an extender to the cement can increase yield, but it can also increase viscosity and thickening time and reduce density, filtration and compressive strength. When specifying an additive, you should know how the cement properties will be affected. By the same token, do not run anything in the cement if you don't know what it is. Find out what the additive is and why it is being used.

Density Control

Normal slurry density for neat cement ranges from 14.8 ppg to 16.4 ppg as can be seen in Table 2. Density control additives are used to increase or decrease the density of the cement mixture. Decreasing the density may be required when lost circulation is a problem. High pore pressures may require increasing the density of the cement.
Lightweight additives or extenders reduce the slurry density. Excess mix water can be used to reduce slurry density to a limited extent. The excess water increases thickening time and free water and decreases compressive strength.

The most common lightweight additive is bentonite. Due to the large surface area, bentonite requires considerable water to be pumpable. Increasing the overall water content of the slurry reduces the weight. Bentonite requires about 1.3 gallons of water for every 2\% bentonite in a sack of cement.

In addition to reducing slurry density, bentonite increases yield and reduces cost per unit volume of cement. As can be seen in Figure 2, the cost of one cubic foot of neat class A cement is $1.34. With

(Note: Compressive strengths are cured 24 hours at 120 °).

**Figure 2** Comparison of slurry cost and compressive strength for several common and premium portland slurries with admixes.

In addition to reducing slurry density, bentonite increases yield and reduces cost per unit volume of cement. As can be seen in Figure 2, the cost of one cubic foot of neat class A cement is $1.34. With
12% bentonite, the cost per cubic foot reduces to $0.89; however, the compressive strength reduces from 2917 psi for neat cement to 500 psi for 12% bentonite.

Almost all additives will have an effect on other properties. Bentonite will reduce free water separation, fluid loss and thickening time (at higher concentrations). It will increase slurry viscosity; and above a concentration of 10% by weight, dispersants must be added to the slurry. Bentonite will promote strength retrogression above 230° F. Cements containing bentonite will be more permeable and have a lower sulfate resistance.

Another material used to reduce density is **pozzolan**. Pozzolans are siliceous material which will react with lime and water to form a compound having the ability to act as a cementing material. When portland cement hydrates, free lime (CaOH₂) is liberated. This compound contributes nothing to strength and is easily leached out by free water contacting the cement which attributes to strength retrogression at high temperatures. Silica combines with the free lime to form Calcium Monosilicate, a cementitious compound. The result is a cement with less tendency to retrogress in strength.

There are two types of pozzolans - natural and artificial. Natural pozzolans are of volcanic origin and are commonly termed volcanic ash. Artificial Pozzolans include glass, furnace slag, and a residue collected from chimneys of coal burning power plants called "fly ash".

Pozzolans will increase slurry volumes, decrease slurry density and provides resistance to attack by corrosive fluids. It will also help to counteract strength retrogression but will not eliminate it. Additions of silica flour are still required.

**Gilsonite** and **Kolite** can be used for density reduction, though they are more often used for lost circulation material in cement. Gilsonite is a black lustrous asphalt with a specific gravity of 1.07. Kolite is crushed coal with a specific gravity of 1.30. Table 5 shows how the density and yield of class G cement changes with various concentrations of gilsonite.
Table 5  *API class G cement with Gilsonite.*

<table>
<thead>
<tr>
<th>GILSONITE (lbs/sk)</th>
<th>WATER (gals/sk)</th>
<th>DENSITY (lbs/gal)</th>
<th>YIELD (cu ft/sk)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>5.0</td>
<td>15.8</td>
<td>1.15</td>
</tr>
<tr>
<td>10</td>
<td>5.4</td>
<td>14.7</td>
<td>1.36</td>
</tr>
<tr>
<td>15</td>
<td>5.6</td>
<td>14.3</td>
<td>1.46</td>
</tr>
<tr>
<td>25</td>
<td>6.0</td>
<td>13.6</td>
<td>1.66</td>
</tr>
<tr>
<td>50</td>
<td>7.0</td>
<td>12.4</td>
<td>2.17</td>
</tr>
</tbody>
</table>

Nitrogen can be used to reduce slurry density in foamed cement. Common slurry densities range from 4 to 11 ppg. The amount of nitrogen (or other gas) added to the cement to achieve a certain density will be a function of the density of the surface slurry and the pressure at which the cement will be placed. Higher placement pressures require larger volumes of nitrogen since nitrogen is a compressible fluid. The density of a foamed cement will change with depth if the nitrogen to cement ratios are kept constant, and the variable density must be considered in the job design.

At times, the density of cement must be increased above that of neat cement to control formation pressures. The density can be increased by using weight material such as barite, ilmenite, hematite, sand and salt. Possible densities and mix water requirements are shown in Table 6. The weight material selected will ultimately depend upon the desired slurry weight. The properties of all high density slurries should be check in the lab at anticipated downhole conditions. Barite and sand are the most common weight materials used with sand being the least expensive.

Table 6  *Weight material for cement.*³

<table>
<thead>
<tr>
<th>MATERIAL</th>
<th>SPECIFIC GRAVITY</th>
<th>GRIND (mesh)</th>
<th>MAXIMUM DENSITY (ppg)</th>
<th>EXTRA WATER NEEDED</th>
<th>EFFECT COMPRESSIVE STRENGTH</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ottawa Sand</td>
<td>2.63</td>
<td>20-100</td>
<td>18.0</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Barite</td>
<td>4.25</td>
<td>325</td>
<td>19.0</td>
<td>20%</td>
<td>Reduce</td>
</tr>
<tr>
<td>Coarse Barite</td>
<td>4.00</td>
<td>16-80</td>
<td>20.0</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Hematite</td>
<td>5.02</td>
<td>40-200</td>
<td>20.0</td>
<td>2%</td>
<td>None</td>
</tr>
<tr>
<td>Ilmenite</td>
<td>4.45</td>
<td>30-200</td>
<td>20.0</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Dispersant</td>
<td>----</td>
<td>----</td>
<td>17.5</td>
<td>None</td>
<td>Increase</td>
</tr>
<tr>
<td>Salt</td>
<td>----</td>
<td>----</td>
<td>18.0</td>
<td>----</td>
<td>Reduce</td>
</tr>
</tbody>
</table>
**Accelerators**

Accelerators are used to shorten thickening time. At lower temperatures, cement takes a long time to derive the desired compressive strength. A neat cement slurry is relatively unreactive at temperatures below 40°F.

A good rule of thumb to remember is that most inorganic materials are accelerators and organic materials are retarders. The inorganic materials must be able to react with the slurry to be an accelerator. Inert inorganic materials such as barite will have no effect on the slurry.

**Calcium Chloride** is the most popular accelerator. Normal concentrations are 2 to 4%. A simple rule of thumb is that 3% calcium chloride will cut the thickening time by one half and double the 24 hour compressive strength. Ten percent calcium chloride will flash set any cement. Calcium chloride will reduce the ultimate compressive strength of cement at concentrations of 6% or more. Calcium chloride is not compatible with most organic polymers used to reduce fluid loss.

**Sodium Chloride** is inconsistent in its application. At low concentrations, salt is an accelerator; whereas at high concentrations, it is a retarder. In the mid range, it depends upon the temperature and the...
class of cement used. At temperatures less than 110° $F$ and at concentrations below 120,000 ppm, it is always an accelerator. As can be seen in Figure 3, the thickening time and compressive strength will vary with concentration and temperature.

Sea water has a sodium chloride content of 20,000 to 30,000 ppm. Salt is always an accelerator in sea water. Salt also stabilizes the flow properties of gel cement at high temperatures.

Other accelerators are ammonium chloride, gypsum, and sodium silicate. Where CMHEC is used as a fluid loss additive, sodium silicate must be used as a retarder. Calcium chloride and salt will not work effectively.

**Retarders**

Retarders increase the thickening time of cement slurries. One common retarder is CMHEC (carboxymethyl hydroxyethyl cellulose) which is made by altering a polymer of anhydro-glucose or cellulose by reacting it with ethylene oxide and mono-chloroacetic acid. It is available in different forms with the difference being the degree to which these compounds have altered the structure of the basic cellulose polymer. The effect on cement is dependent on the degree of substitution and the ratio of carboxymethyl to hydroxyethyl. The molecular weight of the CMHEC is dependent on the degree of polymerization (the number of anhydro-glucose units in the molecule). The molecular weight affects the tendency to increase viscosity. The higher the molecular weight, the larger the molecule and the better fluid loss is controlled. In addition, the larger molecule takes longer to degrade and causes more retardation. The large molecule also causes a high initial viscosity and is the type used in drilling muds. The low viscosity grade (smaller molecule) is used in oil well cements and is called Diacel LWL by Drilling Specialties Company.

CMHEC is always a retarder and never an accelerator. It is effective to temperatures up to at least 450° $F$. The degree of retardation is directly proportional to the amount used, but it is not compatible with some accelerators. CMHEC should not be used in high gel slurries or slurries with normally high viscosity because it causes excess viscosity.
Calcium Lignosulfonate is a retarder that is available in various grades. Some grades are only effective to $165^\circ F$; whereas, other grades are effective to $300^\circ F$. The higher temperature grades are modified with organic acids.

Lignosulfonates are common dispersants used in drilling mud to reduce viscosity. They accomplish the same thing in gel cement slurries.

When used in low concentrations, lignosulfonates are effective retarders; however in high concentrations, they will act as accelerators depending upon the grade. They are more economical than CMHEC.

Sodium chloride in high concentrations (above 120,000 ppm) is a retarder as can be seen in Figure 3. Other retarders are borax and most fluid loss additives.

**Fluid Loss Additives**

All companies use long chain polymers as fluid loss agents such as FLAC, CMHEC, and CHEMAD-1. The compatibility of the fluid loss additives with other additives should be checked. Calcium chloride in combination with most fluid loss additives can cause the cement to flash set. Sodium chloride adversely affects the fluid loss properties of cement slurries. Good fluid loss additives should not affect the density, yield, water requirements, or compressive strength of the cement.

Fluid loss additives will lose their effectiveness with increasing temperature. It is difficult if not impractical to control fluid loss of slurries with high percentages of perlite, diatomaceous earth or pozzolans.

Bentonite also acts to control fluid loss but is not as effective as the long chain polymers.

**Friction Reducers**

Friction reducers are dispersants used to lower the yield point of the slurry allowing the cement to go into turbulent flow at a lower velocity. Typical friction reducers are organic acids, lignosulfonate, alkyl aryl sulfonate, polyphosphate, and salt. Many friction reducers act as retarders.
**Lost Circulation Material**

Lost circulation material can be classified as either granular, laminated, and fibrous material. **Gilsonite, kolite, perlite** and **walnut hulls** are granular materials. Granular materials are best for bridging across fractures. Granular materials are inert to the cement system, so they do not effect the thickening time of the slurry. They will, however, effect the slurry density. Since they have a lower specific gravity than portland cement, granular lost circulation materials will reduce the density of the slurry. In most cases, they will reduce the compressive strength of the cement.

The laminated material used most in cement is **cellophane flake** (Halliburton flocele). The flakes are supposed to form a mat on the face of the formation or bridge off in a fracture. Cellophane flakes have very little effect on cement properties except to reduce compressive strength.

Fibrous materials used for lost circulation in drilling mud contain organic chemicals which can severely retard cement slurries. Therefore, they are seldom used with cement.

**THE CEMENT JOB**

In the final analysis, cement has a function to support pipe and isolate zones. If done in a laboratory any of the slurries discussed would perform the cement function. The important thing in cementing is to get the cement where it is supposed to be - around the pipe, and to do it as economically as possible.

<table>
<thead>
<tr>
<th>Table 7</th>
<th>Flow rates required to produce turbulent flow from laboratory and field data.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>FLOW RATE PER JOB DESIGN (BPM)</strong></td>
<td><strong>FLOW RATE BASED ON FIELD RHEOLOGY (BPM)</strong></td>
</tr>
<tr>
<td>8.6</td>
<td>24.9</td>
</tr>
<tr>
<td>9.9</td>
<td>20.5</td>
</tr>
<tr>
<td>9.1</td>
<td>28.2</td>
</tr>
<tr>
<td>7.0</td>
<td>14.2</td>
</tr>
<tr>
<td>5.8</td>
<td>22.3</td>
</tr>
<tr>
<td>4.3</td>
<td>13.4</td>
</tr>
</tbody>
</table>

An understanding of cement flow properties is required prior to discussing placement mechanics. As is drilling mud, cement slurries are non-newtonian fluids and can be mathematically modeled using the power-law method. The one important point to remember about cement is that it starts out as a non-
newtonian fluid but eventually becomes a solid. Therefore, the flow properties of a cement slurry continually change with time.

The flow properties measured in the laboratory should not be used without reservation. Due to mixing techniques and differences in slurries, field cements will almost never exhibit the same properties. But, the laboratory data are something to work with in determining cement behavior. In the work by Brice and Holmes\(^8\) concerning contact time and turbulent flow, one of their biggest problems was determining the rate necessary for turbulent flow prior to the job in order to have adequate horsepower available. Table 7 illustrates this point. Laboratory data was used to calculate the required flow rate to induce turbulent flow, then field data was used to calculate the flow rate for turbulent flow. Most of the time, there was a significant difference. Since the cement properties change with time, there will also be a difference depending upon when the flow properties are measured.

**Cement Sheath Requirements**

The cement sheath in the annulus has two requirements: 1) it must be strong enough to support the pipe and 2) it must hydraulically isolate zones. Farris\(^9\) related the tensile strength of the cement to the anchoring strength of the annular cement (shear bond). In his experiments, he cemented four feet of 5 1/2 inch pipe inside 9 5/8" pipe with a 15.6 ppg neat portland cement slurry. The force required to produce movement between the two pieces of pipe was measured along with the tensile strength of the cement. The results showed that little or no cement strength is required to support casing; therefore, almost any cement composition will support the casing.

Field work drilling out plugs with 100 psi compressive strength substantiates this work. The industry generally assumes a minimum compressive strength required before drilling out is 500 psi. Davis and Faulk\(^10\) concluded that a compressive strength of 500 psi has a safety factor of from two to five.

Cement to casing bonding is influenced by pipe contraction. Leaving pressure on the casing during waiting on cement time is harmful to the bond and causes a micro annulus. Whenever possible, float equipment should be used to keep cement from flowing back rather than shutting the casing in with pressure at the surface.
As stated earlier, the cement sheath must also hydraulically isolate zones. Loss of a hydraulic seal can be between the casing and cement or between the cement and formation. Studies measuring the hydraulic bond between casing and cement have been performed with water and gas. Bond strength ranged from 200 to 1200 psi with water and 15 to over 400 psi with gas. The hydraulic bond varies with the roughness of the pipe as did the shear bond. It is also a function of the viscosity of the fluid with higher viscosities yielding higher bond strengths. There was no consistent correlation between hydraulic bond and compressive strength of the cement. It should be noted here that zone isolation is consistently obtained in the field at much higher pressures than those found in the study.

The cement to formation bond provides isolation at the formation face. Tests show the bond strength can exceed the formation strength when there is no mud cake. The mud cake will significantly reduce the bond strength, and a hard mud cake will produce higher bond strengths than soft mud cakes. Higher bond strengths are obtained with permeable formations because filtrate is lost to the formation. Again, zone isolation is routinely achieved in the field at values greater than the tests would indicate possible.

To effectively isolate producing zones, cement must also have a relatively low permeability. Tests show that most cements will have a permeability between 0.01 and 0.1 md. Gas reservoirs with a permeability of 0.1 md are produced, but they require extensive fracturing treatment. Clark measured flow through cement cores and concluded that the optimum tensile strength for formation segregation is 50 psi (400 to 500 psi compressive strength). No significant improvement was seen above a tensile strength of 50 psi; therefore, almost any cement with a compressive strength of 500 psi will isolate a zone.

In summary, under normal oil field circumstances, the pipe is adequately supported and nothing can pass around or through the cement sheath. Almost any cement slurry will suffice. Therefore, it remains for us to get the cement around the pipe. That is, displace the mud with cement and let it set up. If a cement job fails, the failure is almost always due to inadequate placement of the cement around the pipe. One exception is with gas migration in the annulus. Gas migration can still occur even if the cement occupies the entire annular area.
Displacement Mechanics in Primary Cementing

Displacement mechanics refers to the displacement of drilling fluid from the annulus, and the subsequent placement of the cement slurry. Factors that affect the removal of drilling fluid from the annulus are:

1. Centralization of the casing.
2. Pipe movement - rotation and/or reciprocation.
3. Drilling fluid condition.
4. Hole conditions.
5. Displacement velocity.
6. Spacer fluids.
7. Mud - cement density differences.
8. Contact time.
9. Directional wells.

Centralization

The benefits of centralizing the casing have been known for many years. It is much harder to remove mud from an eccentric annulus than an annulus with centered casing. For a non-newtonian fluid, the velocity on the narrow side of an eccentric annulus is slower than the velocity on the wide side of the annulus. Therefore, an eccentric annulus promotes channeling. The more eccentric the annulus is; the greater the difference in the velocities. Almost any study conducted shows that mud displacement is improved with centralization.

Since mud is an non-newtonian fluid and pressure is required to break the gel strength, the mud on the wide side of the annulus will move with a lower pressure. Once the mud on the wide side of the casing is moving, sufficient pressure will never be applied to start the mud moving on the thin side promoting channeling. As the annular area decreases, centralization becomes more and more important.

That does not mean the pipe has to be perfectly centralized in order to place cement all the way around the pipe. In practice, perfect centralization can not be achieved. The degree of centralization required will depend upon many factors including the mud viscosity, cement viscosity, inclination, dogleg
severity, tension, displacement rate and the distance between the bottom of the hole and the zone to be isolated.

The degree of centralization is commonly termed percent standoff. If the casing is perfectly centralized, the standoff would be 100%; conversely, the standoff would be 0% if the casing is touching the wall of the hole. The following equation can be used to calculate percent standoff and is illustrated in Figure 4.

\[
\% \text{ Standoff} = \frac{R_b - R_c - C - D_{\text{max}}}{R_b - R_c} \times 100
\]

API Spec 10D\textsuperscript{15} gives the equations for calculating the lateral force on a centralizer and calculating the deflection between the centralizers. The equations are cumbersome and are best suited for a computer. The deflection of the centralizer can be obtained from a chart similar to Figure 5 which can be obtained from the manufacturer of the centralizer.

The restoring force is the force exerted by a centralizer against the casing to keep it away from the bore hole wall. The API specifies the minimum restoring force at a standoff ratio of 67%. So long as the curve in Figure 5 stays above the minimum restoring force, it meets API specifications. The API also specifies the maximum starting force and running force. The starting force is the maximum force required to start a centralizer into the previously run casing string. The maximum starting force will be less than the weight of 40 feet of medium weight casing being used to push the centralizer into the previous casing string. The maximum running force is the maximum force required to move a centralizer through the previously run casing and is always equal to or less than the starting force. It is a practical value which gives the maximum running drag produced by a centralizer in the smallest hole size specified.

Figure 4  Definition of casing and centralizer deflection.
The equations in the API Spec 10D are difficult to follow; however, Mitchell\textsuperscript{16} gives a good example showing how centralizer equations are used. Dowell\textsuperscript{17} also shows an example of how to make a centralizer calculation, but the equation for calculating the deflection between centralizers does not include dogleg severity or pipe tension and will therefore be optimistic.

![Figure 5](image)

**Figure 5**  
Load deflection curve for a centralizer.\textsuperscript{15}

The force on the centralizer can also be determined from the equations in the chapter on torque and drag. The normal force will be the force on the centralizer and is Equation 2. A slightly less accurate method of calculating the normal force is Equation 3 which assumes the dogleg severity is all associated with dropping inclination only. In this case, both the tension in the dogleg and the pipe weight act in the same direction. If the well is building inclination, the normal force caused by tension in a dogleg will be toward the high side of the hole. The normal force associated with pipe weight is always toward the low side of the hole, and the vectorial sum of the two forces will result in a lower value. Therefore, the normal force associated with dropping inclination will always yield the highest force.

The sag between centralizers can be calculated using Mitchell's equations which are Equations 4 and 5.

\[
F_N = \sqrt{(T \times \sin \Delta I + W \times \sin I_{(avg)})^2 + (T \times \sin \Delta A \times \sin I_{(avg)})^2} 
\] (2)
\[ F_N = T \times \sin \left( \frac{DLS \times L}{100} \right) + W \times \sin I_{(avg)} \]  
\[ D_{\text{max}} = \left( \frac{W_f \times \sin I_{(avg)} \times L^4}{E \times 1} \right) \times \left( \frac{1296}{u^4} \right) \times \left( \frac{u^2}{2} - \frac{u \times \cosh[u] - u}{\sinh[u]} \right) \]  
\[ u = \left( \frac{36 \times T \times L^2}{E \times 1} \right)^{\frac{1}{2}} \]  
\[ I = \frac{\pi}{64} \left( OD^4 - ID^4 \right) \]  
\[ BF = 1 \times (0.015 \times MW) \]  
\[ W_b = W_f \times BF \]  
\[ W = W_b \times L \]  

**Example 1:**

Given: 
- Casing outside diameter (OD) is 7 inches
- Casing inside diameter (ID) is 6.276 inches
- Casing weight per foot (W) is 26 lbs
- Diameter of the hole (Dh) is 9 7/8 inches
- Centralizer spacing (L) is 40 feet
- Mud weight (MW) is 9.2 ppg
- Modulus of elasticity (E) is 30 x 10^6
- The tension on the casing (T) is 11,200 lbs

\( I_1 \) is 25.5°
\( I_2 \) is 26.5°
\( A_1 \) is 114°
\( A_2 \) is 116°

The subscript 1 denotes a measured depth 20 feet above the centralizer. 
The subscript 2 denotes a measured depth 20 feet below the centralizer.
Determine: The standoff at the center point between centralizers

Solution: Calculate $BF, W_b$ and $W$.

\[
BF = 1 - (0.015)(MW)
\]

\[
BF = 1 - (0.015)(9.2) = 0.862
\]

\[
W_b = (W_f)(BF)
\]

\[
W_b = (26)(0.862) = 22.41\ lbs
\]

\[
W = (W_b)(L)
\]

\[
W = (22.41)(40) = 896\ lbs
\]

Calculate $\Delta I, \Delta A$ and $I_{\text{avg}}$.

\[
\Delta I = I_2 - I_1
\]

\[
\Delta I = 26.5 - 25.5 = 1^\circ
\]

\[
\Delta A = A_2 - A_1
\]

\[
\Delta A = 116 - 114 = 2^\circ
\]

\[
I_{\text{avg}} = \frac{l_2 + l_1}{2}
\]

\[
I_{\text{avg}} = \frac{26.6 + 25.5}{2} = 26^\circ
\]

Calculate $R_b$ and $R_c$.

\[
R_b = \frac{D_b}{2}
\]

\[
R_b = \frac{9.875}{2} = 4.938\ in
\]

\[
R_c = \frac{OD}{2}
\]

\[
R_c = \frac{7}{2} = 3.500\ in.
\]

Calculate the moment of inertia ($I$)

\[
I = \frac{\pi}{64}(OD^4 - ID^4)
\]

\[
I = \frac{\pi}{64}(7^4 - 6.276^4) = 41.70\ in^4
\]

Calculate the normal force on the centralizer using Equation 2.

\[
F_N = \sqrt{\left[T \times \sin \Delta I + W \times \sin I_{\text{avg}}\right]^2 + \left[T \times \sin \Delta A \times \sin I_{\text{avg}}\right]^2}
\]
The deflection of the centralizer (C) can be determined from Figure 5. At zero lbs, load, the standoff is 1.44 inches. At 261 lbs loads, the standoff is 1.37 inches.

The deflection of the centralizer is:

\[ C = 1.44 - 1.37 = 0.07 \text{ in} \]

Calculate the maximum sag between centralizers \( (D_{\text{max}}) \) assuming the average inclination is still 26°.

\[ u = \left( \frac{36 \times T \times L^2}{E \times 1} \right)^{\frac{1}{2}} \]  \hspace{1cm} (5)

\[ u = \left( \frac{36 \times 11200 \times 40^2}{30 \times 10^6 \times 41.70} \right)^{\frac{1}{2}} = 0.718 \]

\[ D_{\text{max}} = \left[ \frac{W_b \times \sin I_{(avg)} \times L^4}{E \times 1} \right] \times \left( \frac{1296}{u^4} \right) \times \left( \frac{u^2}{2} - \frac{u \times \cosh(u) - u}{\sinh(u)} \right) \]  \hspace{1cm} (4)

\[ D_{\text{max}} = \left[ \frac{22.41 \times 11200 \times 40^4}{30 \times 10^6 \times 41.70} \right] \times \left[ \frac{1296}{(0.718)^4} \right] \times \left[ \frac{(0.718)^2}{2} - \frac{0.718 \times \cosh(0.718) - 0.718}{\sinh(0.718)} \right] \]

\[ D_{\text{max}} = 1.03 \text{ in} \]

Calculate the percent standoff between two centralizers.

\[ \% \text{ Standoff} = \frac{R_b - R_c - C - D_{\text{max}}}{R_b - R_c} \times 100 \]

\[ \% \text{ Standoff} = \frac{4.938 - 3.5 - 0.07 - 1.03}{4.938 - 3.5} \times 100 = 23\% \]

The standoff can also be calculated using Equation 3. The dogleg severity can be calculated from Equation 2 in the dogleg severity chapter.
\[
DLS = \frac{200 \Delta MD}{\Delta \sin \left( \sin^{-1} \left[ \frac{\sin l_1}{\sin l_2} \left( \frac{A_2 - A_1}{2} \right)^2 + \left( \frac{l_2 - l_1}{2} \right)^2 \right] \sin \left( \frac{26.5 - 25.5}{2} \right)^2 \right]}
\]

\[
DLS = \frac{200}{40} \sin^{-1} \left[ \sin(25.5) \sin(26.5) \left( \frac{116 - 114}{2} \right)^2 + \left( \frac{26.5 - 25.5}{2} \right)^2 \right]
\]

\[
DLS = 3.32^\circ/100'
\]

\[
F_N = T \times \sin \left( \frac{DLS \times L}{100} \right) + \left( W \times \sin I_{avg} \right)
\]

\[
F_N = (11200) \left[ \sin \left( \frac{3.2 \times 40}{100} \right) + (896) \sin(26) \right] = 652 lb_f
\]

From Figure 5 the standoff at a load of 652 lbs would be 1.29 inches.

Therefore, the centralizer deflection is:

\[
C = 1.44 - 1.29 = 0.15 in
\]

The sag between centralizers will be the same at 1.03 inches.

Calculate the percent standoff between two centralizers.

\[
\%_{\text{Standoff}} = \frac{R_b - R_c - C - D_{max}}{R_b - R_c} \times 100
\]

\[
\%_{\text{Standoff}} = \frac{4.938 - 3.5 - 0.15 - 1.03}{4.938 - 3.5} \times 100 = 18\%
\]

As can be seen in the example, the difference between using Equation 2 and Equation 3 to determine the normal force on the centralizers is relatively small. The difference between the two equations will be more significant when the tension is higher, dogleg severity is greater and the inclination is higher.

There is another equation that can be used to calculate \( D_{max} \) since Equation 4 is so cumbersome. That equation is derived from the deflection of a beam subject to a uniform load and is Equation 10

\[
D_{\text{max}} = \frac{1.5279 \times 10^{-5} \times W_b \times \sin l \times L^4}{(OD^4 - ID^4)}
\]
Example 2:

Given: The same information as Example 1

Determine: The standoff at the center point between centralizers using Equation 10

Solution: The load on the centralizer and therefore the centralizer deflection will remain constant. Calculate the sag between centralizers.

\[ D_{\text{max}} = \frac{1.5279 \times 10^{-5} \times W_b \times Sin l \times L^4}{(OD^4 - ID^4)} \]

\[ D_{\text{max}} = \frac{1.5279 \times 10^{-5} \times 22.4 \times Sin 26 \times 40^4}{74^4 - 6.276^4} = 0.45 \text{ in} \]

Calculate the percent standoff between two centralizers.

\[ \% \text{Standoff} = \frac{R_b - R_c - C - D_{\text{max}}}{R_b - R_c} \times 100 \]

\[ \% \text{Standoff} = \frac{4.938 - 3.5 - 0.07 - 0.45}{4.938 - 3.5} \times 100 = 64\% \]

The difference using the beam deflection formula is significant. The Dowell equation \(^{17}\) will always calculate out to be five times less than the beam deflection equation. The derivation of the Dowell equation is unknown.

Obviously, the calculation of centralizer placement is too complex for calculations by hand and are best suited for a computer. However, the above calculations can be used to quickly estimate centralizer placement.

There are some rules of thumb that the industry uses.\(^ {3,5} \) Hartog et al states, "As a rule of thumb, these result in one centralizer per two joints and one on each joint at top and bottom of the cemented interval if hole deviations do not exceed 25°. Otherwise, more centralizers should be fitted." Reference 3 recommends using more centralizers than Hartog et al.

Often field personnel complain that the use of centralizers can cause the casing to become stuck or harder to run. These fears are generally not founded. Teplitz\(^ {12} \) actually found it easier to run casing with centralizers. The centralizers also help to prevent differential pressure sticking because they keep the casing away from the wall of the hole.
Adequately centralizing the casing is one of the least expensive methods used to improve the placement of cement around the casing. It is also one of the most effective. If the centralizer program being used now is providing good cement jobs, then there is no reason to change the program. However, if cement jobs are not adequate, then the centralizer program should be examined more closely.

**Pipe Movement**

The displacement efficiency of the cement can be greatly improved by pipe movement. The advantage of pipe movement is so great that it should be employed on all wells whenever possible.

The two types of pipe movement are rotation and reciprocation. Rotation will have a more pronounced effect on displacement efficiency than reciprocation, but specialized equipment is required for rotation. As shown in Figure 6, the drag forces associated with rotation will have a tendency to pull the cement into the narrow side of the annulus while displacing the mud to the wider side. In critical situations, rotation should be considered. There are even specialized liner hangers available designed for rotation. Rotation should begin while conditioning the mud prior to cementing to aid in removing gelled mud from the wellbore. The pipe movement will help break the gel strengths of the mud and get it moving.

Pipe rotation is generally done with a power swivel at 15 to 20 rpm's. The power swivel is used to closely monitor torque. The torque should be maintained below the optimum make up torque of the casing. In highly deviated wells, that is sometimes difficult to do. With a liner, the torque at the surface is not the same as the torque within the liner. A torque and drag program will be required to estimate the torque in the liner in directional wells.

---

**Figure 6**  *The drag forces associated with pipe rotation aid in mud displacement*.17
Due to the requirement of specialized equipment for rotation, reciprocation is the pipe movement most commonly used. Reciprocating the casing while circulating and cementing changes the flow pattern in the wellbore and aids in breaking the gel strength of bypassed mud. Reciprocation is easily accomplished, costs nothing and should be used whenever possible.

Reciprocation of the casing should begin while circulating and conditioning the mud prior to cementing. With reciprocation, it will be easier to remove gelled mud in washouts and in an eccentric annulus. Reciprocation should continue during the cement job until the plug is bumped. Normally, the pipe is reciprocated 15 to 20 feet (5m).

Some operators will not reciprocate pipe because they are afraid the pipe will become stuck off bottom. It is surprising how many operators do not reciprocate casing even though the benefits are so well known. That fear should not preclude reciprocation while conditioning the mud.

It is normal for the pipe weight to change while cementing the well. As the cement is being pumped down the casing, the casing weight will increase due to the weight of the cement inside the casing and frictional pressure losses through the cementing equipment. As the cement enters the annulus, the weight of the casing will decrease because the cement inside the casing is being displaced with a lighter mud. The increased buoyancy due to cement in the annulus will also decrease the string weight. If someone is not aware of the normal changes in string weight, he might think the casing is tending to stick.

The difference between the hook load up and hook load down is a better way to determine whether the casing is tending to stick. If the difference between the hook loads is 20,000, then it should remain near 20,000 even though the actual casing weight is changing. In directional wells, it is more difficult to determine the sticking tendency. The drag in the well should increase with increasing tension in the casing; therefore, the difference between the two hook loads will increase. The higher the initial drag, the more pronounced the effect will be. In any event, the casing should be landed in the proper position when conditions at the rig indicate that the casing is beginning to stick.
One potential problem with pipe reciprocation is surge and swab pressures. The maximum casing running and reciprocating speed should be calculated prior to running the casing in areas where the pressure balance is critical. Rotation does not cause surge or swab pressures.

**Drilling Fluid Condition**

The condition of the drilling fluid makes a difference in how easy it is to displace the mud with the spacer and cement. The thicker the mud, the harder it will be to displace it from the well. It is difficult to get mud with high gel strengths moving especially in an eccentric annulus. That is why it is important to condition the mud prior to cementing.

Usually, the viscosity (and gel strength) of the mud is increased before logging to prevent bridges and fill. After the casing is run, the well should be circulated to condition the mud and hole. Conditioning the mud means to reduce the viscosity and get all the mud moving making it easier for the cement to displace the mud. The viscosity can be reduced by adding water to an unweighted mud system or by chemical thinning in weighted mud systems. Water can also be used to thin weighted mud systems provided the mud weight does not fall below that required to keep the well under control. Remember to take swab pressures into consideration when reciprocating the casing. The mud should not be thinned to the point where weighting material will fall out of the mud or the mud will not have enough lifting capacity to clean the hole.

Conditioning the hole means to get all the mud moving that has been sitting in the hole during the trip. Gelled mud can become trapped in an eccentric annulus and washouts. Pipe movement and circulating for extended periods of time will help to break the gel strength of the trapped mud and get it moving.

The question often arises as to how long should one condition the hole prior to beginning the cement job. That depends upon the condition of the hole and mud. The minimum volume circulated should be equal to the volume of the casing or annular volume whichever is the higher value. The volume necessary to circulate bottoms up should be pump to remove any trip gas from the well before cementing. The volume equivalent to the capacity of the casing should be circulated to make sure there is nothing in the casing that will plug off the float equipment.
Sauer\textsuperscript{19} recommends pumping until a carbide lag or some other material indicates that 95\% of the hole volume is being circulated. The hole volume would be calculated based upon a multi-arm caliper log. Circulation times based upon this method would be longer.

When drilling with water, the minimum volume would be sufficient. Whereas, the circulation volume when drilling with a high density, viscous mud should be longer. When in doubt, circulate a little longer. A few hours of rig time will cost a lot less than a remedial squeeze job.

**Hole Conditions**

The condition of the hole is important from a cementing standpoint. First, the hole should be relatively clean to allow running the casing without much problem. Trouble running the casing could cause damage to some of the centralizers or other casing accessories.

Second, a hole that has a lot of washouts is hard to cement. In a large washout the annular velocity is much lower than the rest of the annulus. The mud and cuttings will be left in the washout in a gelled state making it harder to displace with cement. Washouts promote cement channeling. Scratchers or centralizers can be placed in the washout areas to change the flow pattern of fluid moving through the washout. Pipe movement is very important in wells with large washouts.

![Figure 7](image)

*Figure 7  Velocity profiles of various flow regimes.*

Preventing washouts is something that needs to be considered during the drilling phase, but not all washouts are preventable. Water sensitive clays can wash out when drilling with a water based mud.
Using an inhibited mud will reduce the amount of washout. Shales that slough due to tectonics will not be helped by using an inhibited mud. If you are already getting good cement jobs even though the hole has washouts, there is no reason to spend extra money in the drilling process to prevent the washouts. If you are not getting adequate cement jobs and you have tried everything else, then attempting to control the severity of the washouts during the drilling process may be necessary.

**Displacement Velocity**

The displacement velocity is the annular velocity at which the cement and spacers are pumped into the well. The type of flow depends upon the annular flow rates. The three types of flow profiles are plug, laminar and turbulent flow. Plug flow is the slowest flow rate (30 to 90 ft/min). As can be seen in Figure 7, the velocity profile for plug flow is relatively flat. The next flow rate is laminar flow which has a much more rounded velocity profile. The greater velocity in the center of the laminar flow profile can promote channeling. Once the flow moves into the turbulent range, the velocity profile again flattens out.

Many studies have been conducted to determine the best displacement velocity. Unfortunately, the displacement efficiency is a function of the fluid rheology of the mud and cement, so it makes it difficult to make comparisons between studies.

A summary of the different studies conducted was best expressed by Hartog et al. The best displacement efficiencies were obtained with highly thinned slurries pumped at high rates as shown in Figure 8. He also showed that there is no sudden increase in displacement efficiency when the displacement velocity increases to such an extent that the flow "suddenly" becomes turbulent. The displacement velocity is the governing factor.

They recommend that the displacement velocity be at least 250 ft/min and preferably as much as 350 ft/min to achieve isolation across the producing zone. When pipe movement is not employed, the higher flow rate will be required. Thin slurries should be used in order to minimize pressure losses and maximize displacement efficiency.

In some instances it may not be possible to pump at the higher rates without breaking down the formation. Then, a plug flow type cement job should be considered but only as a last resort. As is
evidenced in Figure 8, plug flow or low flow rates will never achieve the displacement efficiencies realized with higher flow rates.

![Figure 8: Displacement efficiency versus displacement velocity (after Hartog et al.)](image)

Another problem in plug flow is the fact that annular flow rates are not easily predicted. In most instances, the cement being pumped into the casing has a significantly higher density than the mud. This causes the well to U-tube while mixing and pumping the cement. The result is that the flow rate into the well is less than the flow rate out of the well while mixing. The opposite can be true while displacing the cement depending upon the density of the displacement fluid. Figure 9 shows a plot of a typical cement job where the density of the cement is greater than the density of the mud. Because of the U-tube effect, it is sometimes difficult to maintain an annular velocity in the plug flow region. It is much easier to maintain high displacement rates because of the increased frictional pressure losses.
Computer programs have been developed to calculate the flow rates while cementing.\textsuperscript{21,22} These programs can be used to design the cement job pump rates so that displacement velocities can be maintained within the optimum range. Usually, the flow into and out of the well have to be monitored. During critical cementing operations, it may be advisable to monitor flow, but in most instances it is not required.

**Spacer Fluids**

Spacer fluids are used to separate the drilling mud from the cement and to aid in displacing the mud from the annulus. Drilling mud and cement are incompatible and should not mix in the annulus or casing. Drilling muds contain both organic and inorganic materials which may accelerate or retard the cement slurry. Also, excessive thickening occurs at the mud/cement interface. Oil base muds and cement are even more incompatible, and the mud/cement interface may become an unpumpable mass. The thickening of the mud/cement interface will cause channeling. One function of the spacer is to separate the cement and mud which will minimize contamination.

Since the rheology of a fluid makes a difference in the displacement efficiency, the spacer should be a highly thinned fluid. For water based muds, water is an ideal spacer. It is compatible with both cement and mud. The fact that it is a newtonian fluid makes it the thinnest possible fluid. It is also very cheap.

The length of the spacer should be at least 500 feet (150m) in the annulus to allow for adequate separation. The calculated length of the spacer should be based upon the hole volume obtained from the caliper log.

It may not always be possible to pump water as a spacer in weighted mud systems. The reduction in hydrostatic pressure may be enough to cause the well to flow. To prevent a loss in hydrostatic pressure, a heavy pill can be pumped before the water or a weighted spacer fluid can be used. A weighted spacer should still be thin at high flow rates but able to suspend the weighting material at the surface. Polymers are used to viscosify the weighted spacers and the compatiblity with the cement and mud should be checked.
Figure 9  *Flow rates versus time for a typical casing cement job where the density of the spacer and cement are greater than the mud.*

1 - 2  Mixing and Pumping Spacer  
2 - 3  Mixing and Pumping Slurry  
3 - 4  Pumping Stopped to Drop Top Plug. Circulation Stopped.  
4 - 5  Dropping Top Plug. Prepare for Displacement.  
5 - 6  Start Displacement  
6 - 7  Bottom Plug Reaches the Collar. Does Not Break.  
7 - 8  Filling Casing  
8 - 9  Bottom Plug Breaks. Differential Pressure Makes Flow Rate Increase Sharply  
9 - 10  Spacer Starts Rounding the Shoe.  
10 - 11  Spacer Rounding the Shoe. Flow Rate is Constant.  
11 - 12  Slurry Starts Rounding the Shoe.  
12 - 13  Slurry Rounding the Shoe. Flow Rate Constant.  
13 - 14  Fluid Level Reaches Surface. Continuous Flow Takes Place.  
14 - 15  Continuous Flow, Q Out = Q In  
15 - 16  End of Job.
Water cannot be used as a spacer for oil based muds since water and oil based muds are incompatible. To compensate, a base oil spacer is pumped followed by the water spacer. An invert oil emulsion mud results in the casing and formation being oil wet. The base oil and water spacer must contain a water wetting surfactant to change the wettability. Otherwise, the cement will have negligible bond to the formation and casing.

It is not uncommon for operators to use a scavenger slurry ahead of the cement slurry. The pumping order would be spacer, scavenger slurry, lead slurry and tail slurry. The scavenger slurry is a highly thinned cement that has a flow consistency index near 1.0 which is not for a power-law fluid. The volume of the scavenger slurry should not be included in the cement volume calculations.

**Mud-Cement Density Differences**

It seems logical to assume that heavier fluids will fall to the bottom of a well and lighter fluids will rise to the top. Therefore, the cement should always have a greater density than the mud being displaced. This will keep the cement in place after the pumping has stopped. The density difference should be no less than 0.5 ppg.

There is no correlation between displacement efficiency and mud-cement density difference, so no emphasis should be placed on having higher density cements than required.

**Contact Time**

Contact time is defined as the time during which cement flows past a given point in the annulus. The longer the contact time, the greater the chance of displacing the mud from the annulus. Brice and Holmes\(^8\) showed that contact times in excess of ten minutes resulted in the best cement jobs when pumped at high flow rates. Clark and Carter\(^14\) indicated that a contact time of at least four minutes was needed while pumping at high rates, but contact time did not affect displacement efficiency in laminar flow.

At high displacement rates, the contact time does not need to be as long. The contact time needs to be increased as the displacement rates are slowed down. The contact time is measured across the zone of interest or past the shoe on intermediate strings.
**Directional Wells**

In directional wells, a cuttings bed can form on the low side of the hole as explained in the chapter on hole cleaning. A cuttings bed can start forming at an inclination of 20°, but it depends upon the annular velocity. In most cases a cuttings bed will form at inclinations above 35°. Unless the cuttings bed is removed before cement is placed in the annulus, the bed will leave a channel on the low side of the hole. The channel will be filled with cuttings as illustrated in Figure 10. It can also include barite if the well is being drilled with a weighted mud.

![Figure 10](image)

The best way to prevent or minimize a cuttings channel is to clean the hole. The cuttings bed is best cleaned by using a thin drilling fluid at high annular velocity in excess of 180 feet per minute. Weighted muds should have sufficient viscosity and yield point to minimize barite sag as explained in the chapter on hole cleaning.

Once a cuttings bed has formed during the drilling process, it is difficult to remove. Circulating for an extended period of time at high annular velocities is the only way to remove the cuttings bed. This can be done while circulating and conditioning the mud prior to cementing. Pipe movement can significantly affect the removal of the cuttings bed. Tests performed in the lab showed a sizable reduction in the cuttings bed channel when pipe movement was used. Reciprocation and rotation were just as effective.

Another problem associated with high angle or horizontal wells is the formation of a water channel on the high side of the hole. After the cement is in place, free water can separate from the cement and migrate to the high side of the hole as shown in Figure 10. In directional wells, free water should be...
maintained at zero percent to eliminate the possibility of a channel on the high side of the hole. The section on free water discusses the means to reduce the free water content of the cement.

Of the two channels, the free water channel would be more likely to prevent isolation in a wellbore. Water has no resistance to flow and could be easily moved. Conversely, a cuttings bed would have a significant resistance to flow and would be difficult to remove. It would not be reasonable to think that a cuttings bed could cause a loss of isolation over distances of a few tens of feet. Also, the permeability of cuttings bed would be very low. Where a cuttings bed could be crucial is when perforating near a water contact. The short distance involved might allow communication through the channel.

Segregation of cement particles can also be a problem in a directional well. Before the cement sets, some of the particles may settle to the low side of the wellbore. This will leave a more dense cement near the low side and a lower density cement near the high side of the hole. Cements with adequate viscosities and gel strengths will resist particle segregation. In the case of gas migration, the higher gel strengths may contribute to early loss of hydrostatic head allowing gas to enter the wellbore. Segregation has not been shown to be a major problem; therefore, the gas migration problem should take precedence.

**Summary**

In summary, almost any cement will support the pipe and isolate the zone provided the annulus is filled with cement. All that remains is to get the cement in place. The following steps can be taken in order to ensure an adequate cement job.

1. If cementing is a potential problem, try to minimize the size of the washouts during the drilling process across the intervals to be isolated. Unfortunately, that may not always be possible and may be cost prohibitive.

2. Centralize the casing. Take into account dogleg severity and hole inclination in centralizer placement. Proper centralization is one of the major factors contributing to a good cement job.

3. Circulate the hole and condition the mud prior to cementing. The mud should be thinned as much as possible while still maintaining adequate lifting capacity and
density. In directional wells with weighted drilling fluids, the problem of barite sag may limit the minimum viscosity.

4. Reciprocate (or rotate in critical situations) the casing while circulating and cementing. Unless the casing starts to stick, the casing should be reciprocated until the plug bumps.

5. Pump a thin spacer fluid in front of the cement. The spacer should be compatible with both the drilling fluid and the cement.

6. Pump a thin cement slurry at high displacement rates. Use plug flow techniques only when high rate displacement is not possible.

7. Use the most economical slurry possessing satisfactory properties.

8. Do not hold pressure on the casing after the plug has bumped unless the float equipment does not hold. Keeping pressure on the casing while the cement sets can cause a micro annulus.

9. In high angle directional wells, prevent the formation of a water channel on the high side of the hole. Minimize the cuttings bed on the low side of the hole by cleaning the hole with adequate annular velocities.

Do what has to be done to get a good cement job. In some areas it is easy to get a good cement job while other areas can be more difficult. Do not do more than has to be done to get a good cement job. Doing more can cost money needlessly. For instance, there is no reason to spend money on the equipment necessary to rotate the casing when simple, inexpensive reciprocation has proven to be effective in the past. The same is true of high priced additives. If the cement jobs are adequate, do not do more. Consider doing less but do not do more.

**Gas Migration**

Gas migration is the only problem that can still exist even if the annulus is completely filled with cement. The gas flow occurs after the cement has been placed behind the casing, and the plug has been bumped. Gas will enter the cement because of a loss of hydrostatic head. That gas will then channel through the cement and enter into another zone or return to the surface.
During hydration, cements go through a state in which they do not behave as either a solid or a liquid. This is called the transition state. During the transition state, cement slurries are incapable of transmitting full hydrostatic pressure, and the volume of the cement slurry decreases due to chemical hydration and fluid loss. This decrease in volume (along with the cements inability to transmit hydrostatic pressure) leads to a decrease in annulus pressure allowing gas to enter the wellbore. A very small reduction in cement volume can result in a large reduction in annulus pressure. The cement has attained enough gel strength to support itself and hydrostatic pressure can no longer be transmitted through the cement column. For this reason, holding pressure on the annulus will not significantly affect the problem of gas channeling.

Controlling the fluid loss will reduce the volume of filtrate lost to the formation thereby reducing the shrinkage and attendant pressure loss within the transition state cement. It will not prevent the pressure loss completely. The initial hydration reactions of cement particles leads to a 0.1 to 0.5% reduction in volume. Since the cement has enough gel strength to support itself, a reduction in pressure will occur.

If the pressure falls below the formation pore pressure, formation fluids will migrate into the cement. Water or oil entering the cement from the formation will reduce or stop the pressure loss in the cement column. The viscosity of the water or oil is high enough to prevent significant vertical migration through the cement column. However, gas is different. It has a low enough viscosity to allow vertical migration through the cement. As it approaches the surface, the gas expands causing it to migrate even faster.

If gas migration is a problem, there a number of things that can be done to reduce or eliminate it. First of all, every effort should be made to displace the mud from the annulus and replace it with a good cement sheath.

The slurry used should have a low fluid loss to prevent loss of filtrate from the slurry. Depending upon the author, the recommended fluid loss ranges from less than 20 cc to 100 cc per 30 minutes to prevent gas migration. All fluid loss measurements are conducted at 1000 psi and bottomhole circulating temperature.
Additives can be mixed in the cement to help prevent gas migration. Some additives will generate gas while the cement is curing. The gas being generated will compensate for the volume reduction due to hydration and keep the pressure within the cement column above formation pressure. These additives have been tested in the field with good success.

Some of the gas generating additives will form hydrogen gas which is explosive. Precautions should be taken if this type of additive is used.

Another method used to prevent gas migration is to use a delayed gel strength slurry.\textsuperscript{1,26} Cement that is characterized by a gel set has a slow gain in consistency until the final pumping time is reached. A right angle set is exhibited by a delayed gel strength slurry. The slurry remains liquid for a period of time, and the gain in consistency is rapid at the end. Figure 11 represents a consistometer chart for both a gel set slurry and a right angle set slurry.

Remember that cement shrinks as it sets which allows the pressure to fall within the cement column. The gel strength developed by the cement prevents the annular pressure from being transmitted through the cement. By using a delayed gel slurry, the cement stays thin for a longer period of time. That allows the hydrostatic pressure to be transmitted for a longer period of time. Once gel strength starts to develop, it does so rapidly. Therefore, there is less time for gas to enter the cement and channel before the cement sets up enough to prevent gas migration.

Another method used recently involves rotating the pipe during the static gelation period. Pipe rotation allows the hydrostatic pressure to be transmitted along the casing even after the cement has started to gel. After rotation is stopped, restriction to flow or migration in the cement filled annulus develops very rapidly. Tests conducted using this method\textsuperscript{27} showed that rotation continued to high static gel strength values resulted in increased shear bond and hydraulic bond for normal cement water ratios. Bond strength for high cement to water ratios (1.6 w/c) were reduced.
Figure 11  Consistometer data for a gel set and a delayed gel set slurry.

REFERENCES
17. Dowell Schlumberger; Cementing Technology, 1984, Chapter 9, pp 2-4.
NOMENCLATURE

\( A_1 \) = Azimuth at upper survey point, degrees
\( A_2 \) = Azimuth at lower survey point, degrees
\( BF \) = Bouyancy factor, dimensionless
\( C \) = Centralizer deflection due to the lateral load
\( D_h \) = Diameter of hole, inches
\( D_{\text{max}} \) = Deflection or sagging of the casing string between centralizers, in.
\( E \) = Modulus of elasticity, in/in (30 \( \times \) 10^6 for steel)
\( F_N \) = Normal force, lbf
\( I \) = Moment of inertia, in\(^4\) \( \left( \frac{\pi}{64} (OD^4 - ID^4) \right) \)
\( I \) = Inclination
\( I_1 \) = Inclination at upper survey point, degrees
\( I_2 \) = Inclination at lower survey point, degrees
\( I_{\text{avg}} \) = Average inclination between two survey points, degrees \( \frac{l_1 + l_2}{2} \)
\( L \) = Centralizer spacing, feet
\( MW \) = Mud weight, ppg
\( R_b \) = Radius of borehole, in.
\( R_c \) = Radius of casing outside diameter, in.
\( u \) = Constant, dimensionless
\( W \) = Bouyant weight of a section of pipe, lbs
\( W_b \) = Bouyant weight per foot of pipe, lbs/ft
\( W_f \) = Air weight per foot of casing, lbs