Selection of Centralizers for Primary Cementing Operations

API TECHNICAL REPORT 10TR4
FIRST EDITION, MAY 2008

EXHIBIT # 354

WIT:

Selection of Centralizers for Primary Cementing Operations

Upstream Department

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Acknowledgment

API Subcommittee 10 acknowledges the assistance from industry manufacturers in compiling this document. Many of them provided photos of their centralizers, and those illustrations are included in this document.

1 Introduction

The proper centralization of the casing for primary cementing has long been a critical step in quality cementing. Lack of proper centralization can lead to severe cementing problems, including lack of zonal isolation and improper casing support. The goal of this document is to provide the petroleum industry with information for three types of centralizers, their selection and application, and their advantages and limitations.

2 Benefits of Centralization

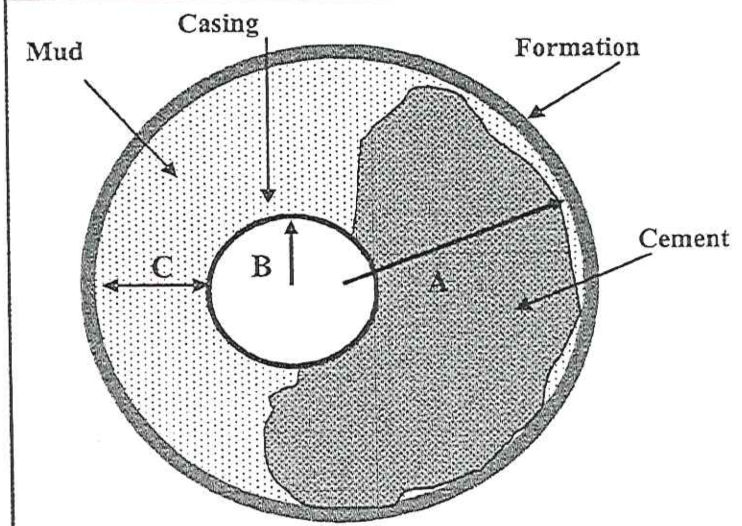
When performing primary cementing jobs, the casing should be centralized in the wellbore for three reasons:

1. to help get the casing to bottom (this includes reduction of the potential for sticking of the string);
2. to help move the casing during mud conditioning and during the cementing job;
3. to provide an optimal path for fluid flow during mud conditioning and cementing allowing for effective mud removal to achieve zonal isolation.

Field experiences, numerous large-scale experiments and computer simulations have shown that poor casing centralization can be detrimental to the cement job, particularly in narrow annuli. Therefore, a good centralization program should aim for high levels of standoff, which produces improved mud removal, particularly across critical areas of the wellbore, that is, those areas where isolation is required. It is imperative the user investigate the standoff at all points, especially between the centralizers.

2.1 Definition of Standoff

Standoff is defined by API/ISO documents (e.g. ISO 10427-2) as the smallest distance between the outside diameter of the casing and the wellbore. The standoff ratio is defined by the same documents as the ratio of standoff to the annular clearance for perfectly centered casing expressed as a percentage (%). Annular clearance for perfectly centered casing is the wellbore diameter minus the casing outside diameter divided by two. Figure 1 illustrates standoff and annular clearance.



$$\% \text{ Standoff} = \frac{C}{A - B} \times 100$$

A = Distance from center of Wellbore to Formation
B = Distance from center of Casing to OD of Casing
C = Smallest distance from OD of Casing to Formation

NOTE Failure to place cement completely around the casing, as portrayed in the figure, is a likely result of inadequate standoff (centralization) and results in failure to achieve isolation.

Figure 1—Definition of Standoff

2.2 Casing Centralization and Centralizing Devices

Casing centralization requires mechanical devices (centralizers) to keep the casing away from the wellbore and/or from the cased sections of the well.

Significant issues include:

1. the centralizer must provide enough load support to overcome the normal forces tending to lay the casing against the formation wall, particularly in deviated holes, horizontal holes and through doglegs;
2. enough centralizers should be used to provide good casing centralization over the needed intervals (including at points between the centralizers);
3. it is normally assumed (however not always the case) that the formation can provide enough support for the tools (minimum centralizer embedment).

3 General Discussion

3.1 Centralizer Types Available

The industry has developed three main types of centralizers: bow-spring, rigid, and solid.

3.1.1 Bow-spring Centralizer

The bow-spring centralizer is composed of flexible spring bows (heat-treated steel springs) attached to two collars. By design the bows are flexible enough to allow passage of the centralizer through restrictions but are also expected to provide standoff in enlarged hole sections. The springs come in various shapes and dimensions. The uncompressed outside diameter (OD) of a bow-spring centralizer may be much larger than the nominal hole (bit) diameter; thus, this type of centralizer can potentially "centralize" the pipe in moderately washed-out zones. Double-bow centralizers are also available. The double-bow centralizers can provide good restoring forces with low starting and running forces. Double-bow centralizers have a lesser maximum OD than conventional bow-spring centralizers and might sacrifice standoff in enlarged holes. Double-bow centralizers may also be considered semi-rigid, as will be discussed later in this document.

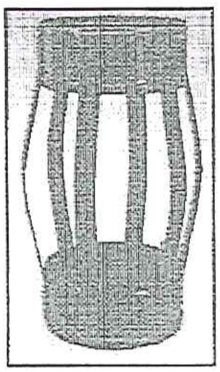


Figure 2—Example of a Bow-spring Centralizer

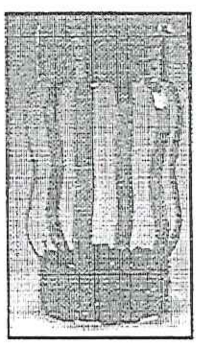


Figure 3—Example of a Double Bow-spring Centralizer

3.1.2 Rigid Centralizer

Rigid centralizers are made using non-flexible bands attached to collars. The bands are not designed to flex, and therefore, tend to maintain a constant OD. The centralizers exhibit minimal (or no) flexibility, but may have some ability to deform in hole restrictions, depending on their construction. Several types of rigid centralizers are available from manufacturers.

A subclass within the rigid centralizer category can be made for certain type centralizers. For example, the double bow-spring centralizer is considered a bow-type but may also be considered a "semi-rigid" centralizer. This is because the bows of these centralizers flex, but after small deflection, they become essentially rigid.

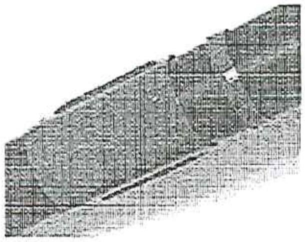


Figure 4—Example of a Rigid Centralizer

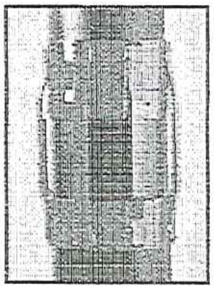


Figure 5—Example of a Rigid Centralizer—a Slim-hole Centralizer

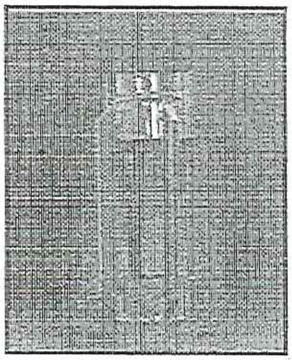


Figure 6—Example of a Rigid Centralizer

3.1.3 Solid Centralizer

Solid centralizers are manufactured with completely non-flexible blades or bands. These centralizers have solid bodies and solid blades. They do not flex in hole restrictions. Examples of this type of centralizer include those made of aluminum, zinc alloy, and steel. Blades are available either straight or spiraled.

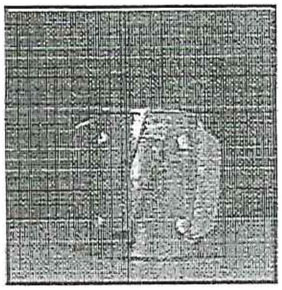


Figure 7—Example of Steel Spiral Solid Centralizer

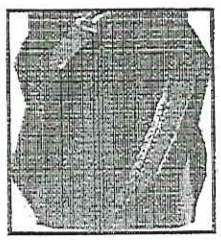


Figure 8—Example of Steel Spiral Solid Centralizer

3.1.4 Integral Solid Centralizer

Another type of solid centralizer is the integral or sub. These are made up as part of the casing itself (like pup joints). Figure 9 illustrates this type of centralizer. Integral bow-type centralizers are also available.

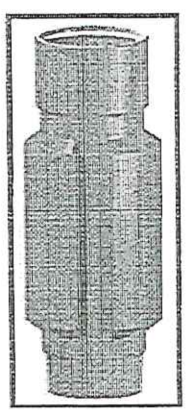


Figure 9—Example of an Integral Solid Centralizer

3.1.5 Roller Type Solid Centralizer

Roller blade-type centralizers may greatly assist running the casing in extended-reach wells. The rollers have been shown to substantially reduce the drag and torque. Designs of roller centralizers are available for running the casing and also for allowing rotation of the string. Figure 10 shows a running-rotating combination.

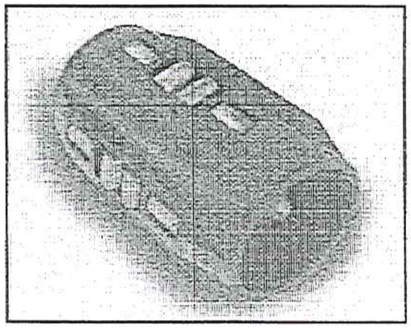


Figure 10—Example of Solid Roller Centralizer for Running and Rotating of the Casing

3.1.6 Centralizers Bonded onto the Pipe

A recently-introduced centralizer is designed for use in slim-type well configurations. The centralizers are formed and bonded directly onto the pipe. The centralizers are made from composite material consisting of carbon fibers and ceramics. Figure 11 illustrates this type of centralizer.

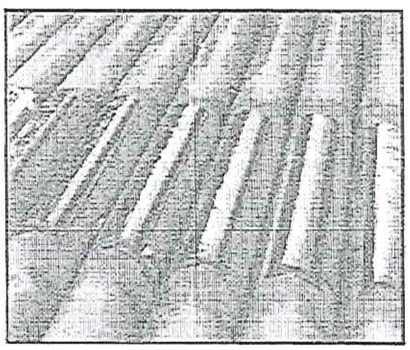


Figure 11—Example of Centralizers Bonded Directly onto the Pipe

3.1.7 Modified Bow-spring Centralizer

A modified bow-spring centralizer with a reduced OD and bows that meet the API specification has been introduced. The centralizer has lower starting and running forces because of the smaller OD compared to conventional bow-spring centralizers.

Figure 12—Example of a Limited OD Bow-spring Centralizer

3.2 Advantages and Limitations of Centralizer Types

3.2.1 Bow-spring

1. This centralizer type has the ability (flexibility) of adjusting to varying hole sizes (can potentially maintain standoff even in irregular size holes).
2. Certain designs incorporate fins to induce swirl (turbulence).
3. Because of the spring bows, these centralizers tend to exhibit high starting and running forces.
4. In highly deviated or horizontal wellbores, improper use of these devices may prevent the casing from getting to bottom.
5. If the centralizer becomes stuck, it may break or the stop rings may slip, potentially forming a "nest" of centralizers.
6. These devices may not provide desired standoff under high lateral load conditions.

3.2.2 Rigid

1. Because they cannot be collapsed by normal forces generated in the hole, they can ensure a minimum standoff in high normal force situations (provided there is minimum embedment in the borehole wall), such as across severe doglegs and high angle or horizontal wells.
2. Running forces are generally much lower than for bow-spring centralizers.
3. The starting forces are zero.
4. By design, solid centralizers have a fixed OD. They do not adjust to varying (large) hole sizes.
5. Some designs allow for deformation of the fins to help run the centralizer through hole restrictions.
6. If the centralizer becomes stuck, it may break or the stop rings may slip, potentially forming a "nest" of centralizers.
7. Several designs include spiral blades to induce turbulence around the devices.
8. Some designs provide low restriction to flow.

3.2.3 Solid

1. Because they cannot be collapsed by normal forces generated in the hole, they can ensure a "minimum" standoff in high normal force situations (provided there is minimum embedment in the borehole wall), such as across severe doglegs and high angle or horizontal wells.
2. Running forces are generally much lower than for bow-spring centralizers.
3. The starting forces are zero.
4. By design, they have a fixed OD. The devices cannot adjust to varying (large) hole sizes.
5. The designs do not allow for deformation to help run the centralizer through hole restrictions. If the centralizer becomes stuck, it may break or the stop rings may slip, potentially forming a "nest" of centralizers.
6. Several designs include spiral blades to induce swirl flow around the devices.
7. Some solid designs may present high restrictions to flow. Care should be exercised when using them in narrow annuli.

3.3 Selecting the Type of Centralizer

The selection of the proper centralizer for a particular well application is a critical engineering consideration. The goal of the centralizer program should be to optimize the centralization of the casing in the wellbore to aid in proper mud removal and achieve zonal isolation. Depending on a number of design criteria, the proper centralizer for a particular application may be a bow-spring, rigid, or solid centralizer. In any given well, there can be application for all three types of centralizers, and only by evaluating all available data can the proper centralizer(s) be selected.

Not all centralizers available to operators are of high quality, and the user is cautioned to consider construction quality of the device when selecting a centralizer. There are API/ISO documents available with methods to test the quality of bow-spring centralizers (i.e. ISO 10427-2). Similarly, API TR 10TR5 defines additional methods to test the quality of rigid or solid centralizers.

Bow-spring centralizers are commonly used in cementing operations and can provide a high level of standoff. Double-bow centralizers can also offer good standoff with reduced levels of running forces. There are many situations where bow-spring centralizers will not perform as required because of large normal and/or running forces, such as found in high dogleg situations. For these circumstances and for complicated well paths (high deviations, high angle change, severe doglegs, extended reach, S-shapes, etc.) the use of solid or rigid centralizers may be required. The selection of centralizer type (or combination of centralizers) should be made using a centralizer placement simulator for the actual condition of the well.

Torque forces and drag (total running forces) should be calculated, as well as the standoff, up and down the entire hole using the actual hole deviation and caliper data. The properties (running, restoring forces, etc.) of the centralizers being considered should be used in the calculations.

Table 1 gives parameters used in examples of computer-generated simulations (see Figures 13 and 14). The first example shows a case in which the pipe could not be run to bottom because of the elevated drag generated by bow-spring centralizers. The second example shows that a rigid centralizer would allow the pipe to get to bottom. The centralizer of choice to use in this case is a rigid centralizer.

Table 1—Example of Parameters Used in Generated Simulation

Parameter	Value
Casing size	7-in., 23 lbm/ft
Hole	8 1/2-in.
Mud	10 lbm/gal
Horizontal hole section	6,000 ft

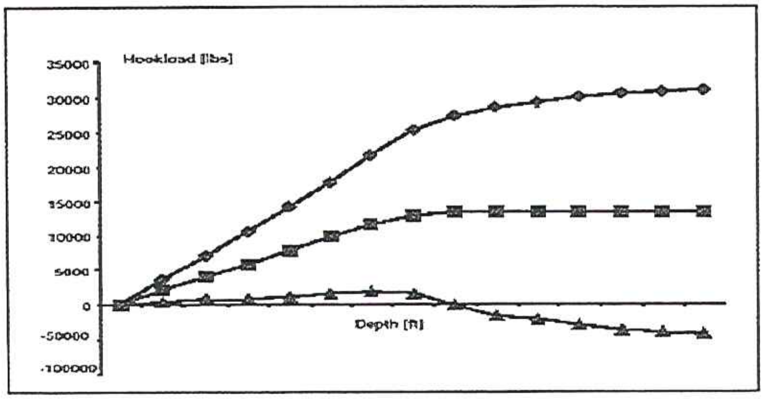


Figure 13—Computer Simulation for the Case with Bow-spring Centralizers Indicates the Casing Cannot be Run to Bottom

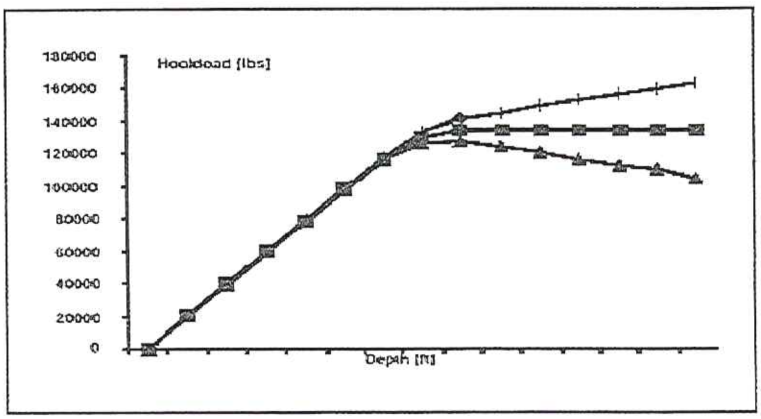


Figure 14—Computer Simulation for the Case with Rigid Centralizers Indicates the Casing Can be Run to Bottom

Legend for Figures 13 and 14:

- Upper line: upstroke hook load
- Central line: neutral weight
- Lower line: down stroke hook load

The example illustrates the effect of high normal drag forces compelling the operator to use rigid-or solid centralizers because of specific well conditions.

It should be emphasized that the critical point for design is between centralizers and this may lead to a higher centralizer density (whether rigid or bow-spring). Mud removal efficiency is affected by standoff, therefore, standoff should be optimized based on requirements for mud removal and centralizer placement should be based on the required standoff.

3.4 Drag Force vs Standoff Considerations

As illustrated in the previous example, particularly in highly deviated, extended-reach and horizontal wells, it often becomes necessary to design the centralizer program considering the need for both high standoff and low drag (total running) forces. Under these conditions, the problem becomes not just one of generating good centralization for good cement placement, but one of being able to run and move the casing.

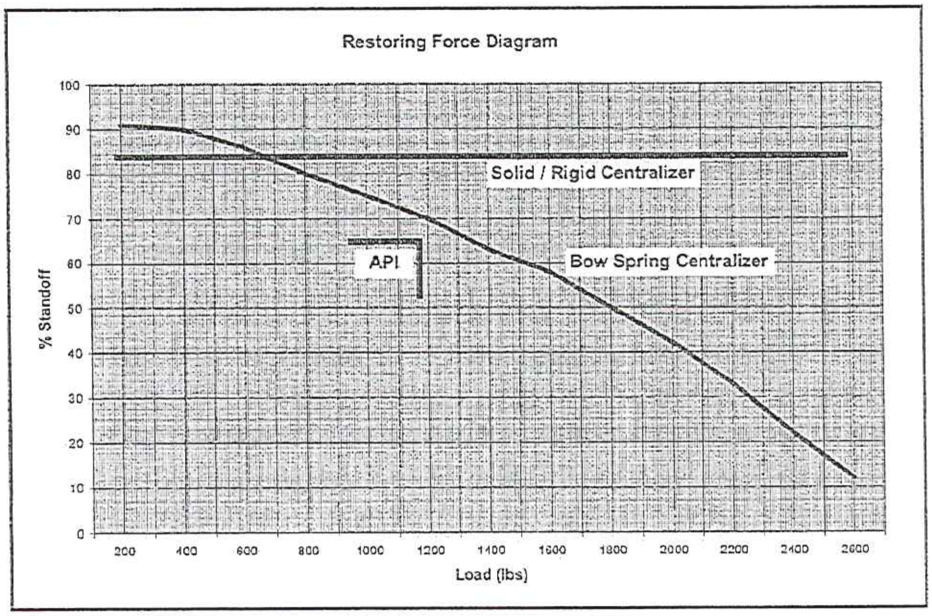


Figure 15—Example of the Effect of Normal Forces on Selection of Centralizer Type

Rigid and solid centralizers have lower running forces than bow-spring centralizers, but their fixed OD limits the ability to maintain high standoff in enlarged holes. In addition, the drift ID of the previous casing often limits the OD of the centralizer that can be run to centralize the casing in the open hole. Under these circumstances, the size (OD) of the rigid or solid centralizer that can be used in a given case may be too small to provide the desired degree of standoff in the open hole section.

This condition becomes more severe in cases where the open hole has been under-reamed, has washouts, or ovality. The following example examines only standoff at the centralizer.

NOTE The critical standoff ratio is at the sag point of the casing, but those calculations require the use of a simulator. Standoff at the casing sag point will be worse than the standoff at the centralizer.

The calculation of standoff for a rigid or solid centralizer (at the centralizer) is as follows:

$$\% \text{ standoff} = (Rc - Rp) / (Rb - Rp) \times 100 \quad (1)$$

(assumes the centralizer is contacting the wellbore wall and is not embedded)

where

- Rc is radius of solid/rigid centralizer (OD/2);
- Rp is outside radius of the casing (OD/2);
- Rb is radius of the borehole (hole size/2).

It should be noted that according to equation 1, it is not possible to obtain 100 % standoff with rigid or solid centralizers since the maximum OD of these types of centralizers is less than the OD of the hole. Likewise, bow-spring centralizers might not give 100 % standoff because there will be some side loads present that will tend to flatten the centralizer blades.

3.4.1 Example Standoff Calculation

- Previous casing: 9 $^5/_8$-in., 43.5-lbm/ft, drift diameter: 8.599-in.
- Open hole (bit size) 8.5-in./7-in. casing to be centralized in the open hole.
- Max. OD of rigid or solid centralizer that can be safely run inside the previous casing: 8.599-in. – $^1/_8$-in. = 8.474-in.
- Recommended solid or rigid centralizer OD (from manufacturer tables) for an 8.5-in. hole: 8.25-in.
- % standoff in 8.5-in. hole = (4.125 – 3.5)/(4.25 – 3.5) ×100 = 83 %.

Eighty-three percent is the best standoff that can be obtained with a solid or rigid centralizer for this example well. It assumes that the hole is equal to the bit size, which is normally not the case. In a situation where the hole size is larger than the bit size, it is possible to see a limitation (from a standoff point of view) with fixed OD centralizers as shown in Table 2.

Table 2—Standoff of Rigid or Solid Centralizers vs Hole Size (Based on Example 3.4.1)

Hole OD (in.)	% Standoff at the Centralizer
8.50	83
8.75	71
9.00	63
9.25	56
10 (washout)	42

Eighty-three percent standoff may or may not be sufficient for a quality cementing job. The standoff obtained by rigid centralizers may not be adequate for effective mud removal and zonal isolation. Conversely, bow-spring centralizers may not be able to withstand the side loads exerted in a wellbore thereby limiting the degree of standoff that can be designed.

It is important to remember at this point that 67 % standoff was *never* a recommended level by API/ISO. It is simply a means to help manufacturers produce API-quality centralizers (bow-spring). It is also noted that in all the cases in Table 2, the minimum gap between the casing and the wellbore at the centralizer is 0.25-in., assuming embedment of the centralizer at the wellbore is negligible.

Another important point is whether the centralizers are installed on the casing before the actual size (caliper) of the open hole is known (hole size is often estimated from offset wells). In this situation, if the actual hole turns out to be enlarged, it might be too late to change the previously selected centralizer type.

Bow-spring centralizers for this example can have a maximum OD of over 13-in., with a compressed OD of as low as 8.231-in. (less than the previous casing drift diameter). Thus, for such a well with an enlarged hole, bow-spring centralizers may provide higher degrees of standoff as long as the running and normal forces are acceptable.

3.5 Location and Number of Centralizers to Obtain a Desired Standoff

Calculating the location and number of solid and rigid centralizers to obtain a given desired standoff is easier than for bow-spring centralizers because the restoring force of the centralizer is not a factor in the calculations. At the centralizer, the standoff is simply calculated using the previously given Equation 1. This equation assumes that the centralizer is in contact with the formation at some point and that there is no embedment of the centralizer into the formation. Between centralizers, the casing sag point should be estimated using the equations given by API and ISO documents dealing with recommended practices for the use of bow-spring centralizers (ISO 10427-2). For calculations of casing sag the equations used for bow-spring centralizers apply, with the exception that solid and rigid centralizers do not flex due to the normal forces.

3.6 Estimating Drag and Torque When Using Rigid and Solid Centralizers

API and ISO documents (for example, ISO 10427-2) contain the needed formulas to calculate the normal forces for a given hole-casing geometry based upon the vector sum of the weight and the tensile components. Factors affecting the calculations include casing weight, mud and cement slurry densities, well inclination and dogleg severity. After the normal forces are calculated up and down the casing for the given well configuration, friction forces can be calculated by multiplying the normal forces by the estimated dimensionless friction factor. The total drag can then be estimated by adding up the calculated localized friction forces.

Similarly, assuming the casing rotates inside the centralizer (centralizer is fixed against the formation) localized torque components are estimated using the calculated normal forces and the estimated friction factor. Total torque at the surface is estimated by adding up all the torque components. These calculations require a computer simulator, particularly for complicated well trajectories and severe dogleg sections.

3.7 Friction Coefficients

The value of the friction coefficient for a centralizer is influenced by the material used to manufacture the centralizer, the type of centralizer (bow-spring, rigid and/or solid), the blade orientation, the mud system used (level of lubricity) and the formation. Friction coefficients are dependent on the mud type and its additives (including lubricants). Typical field-used friction coefficients are given below.

- Water-based muds: 0.25 to 0.35
- Oil-based muds: 0.15 to 0.25

Laboratory testing methods have been developed to measure friction coefficients for different construction materials and mud systems. A test method that can be used for comparison among different centralizer materials and mud systems is given and discussed in API TR 10TR5.

3.8 Potential Benefit of Centralizer-induced Swirl (Turbulence)

Many centralizers are configured in such a way as to induce swirl during pumping. (Figures 7 and 8) Swirl can be beneficial to the displacement process. Several documented large-scale experimental studies have been published illustrating the advantages of swirl during the mud displacement process. Field reports also have indicated that the use of a swirl inducing device (SID) can be helpful during cementing jobs.

Consideration should be given to the degree of mud removal produced by swirl. Rigid and solid centralizers may not provide as high standoff as bow-spring centralizers but may offer the benefit of improved mud displacement owing to swirl. The industry has conducted experiments to measure the angle and length of the swirl of different swirl-inducing devices. The bulk of these studies, however, have been performed in pipes with no permeability present, for example, the Joint Industry Project at Southwest Research Institute (SWRI), San Antonio, Texas in 1991. The experiments always showed a rapid initial decrease in swirl downstream of the device, which decayed at a slower rate as the distance from the tool increased. Higher swirl angles have been found to always concentrate in the very near proximity of the devices. This behavior is observed even at high rates (Reynolds Numbers).

A typical experiment from the SWRI project is shown in Figure 16. Notice the high angles concentrated very close to the device and then declining very rapidly away from the centralizer. Experiments and mathematical simulations have also shown that even minor hole enlargements and eccentricity significantly reduce the potential beneficial effects produced by the swirl due to large portions of the flow bypassing the device.

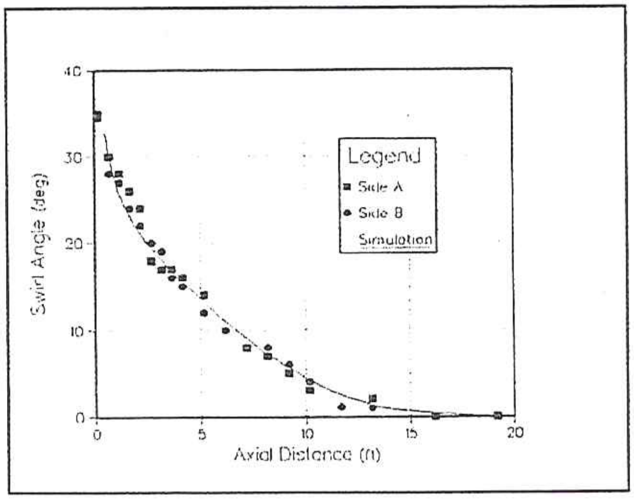


Figure 16—Typical Swirl Angle vs Distance Away from the Centralizer

There is an industry perception, based on the SWRI studies and other large-scale experiments, that flow turning around the pipe implies the cement slurry will always surround the entire annulus for a long distance during the cementing job. Unfortunately, that is not always the case in a downhole environment. The main reason for the confusion is that very few experiments have been conducted under realistic downhole conditions, including with the presence of permeability and hole inclination. Permeability has a dramatic effect on the mobility of mud filter cake and solids-laden beds on the low side of inclined holes. Due to partial dehydration and gelation, mud films across permeability often exhibit levels of mobility resistance orders of magnitude greater than non-dehydrated mud portions. This depends also on the mud type and its properties. Oil-based muds, for example, generate the most mobile mud films. To remove the partially dehydrated gelled mud films, spacer fluids normally have to be designed with rheologies sufficiently high to apply needed levels of wall stresses, or to chemically soften the mud films. Mud films around the cement, across permeable sand can be seen in the Figures 17 and 18, from a large-scale experiment.

The photo in Figure 17 shows a swirl-inducing centralizer in an enlarged hole section across permeability. Notice the presence of immobile, dehydrated gelled mud across the permeability, and a bed of solids on the low side of the hole.

These devices were also tested in an inclined, permeable hole with small clearance between the blades and the hole. As expected, they did a better job of helping remove the mud than across washout hole sections. In the very near proximity of the swirl-inducing centralizers, fewer settled solids and partially dehydrated mud layers were observed than away from the device, but the device did not completely clean the annulus, even where the device was located.

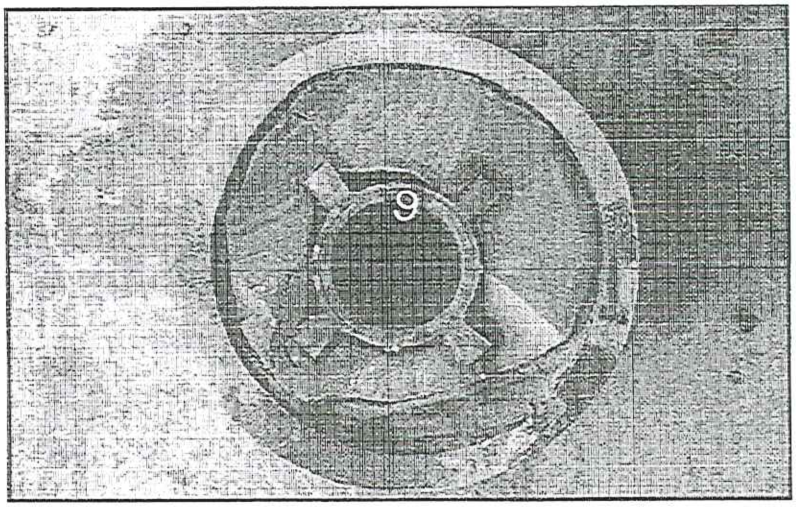


Figure 17—Swirl-inducing Centralizer in a Deviated, Enlarged Hole with Permeability

Although Figure 18 is not very clear, it nonetheless illustrates the point. A bed of solids can be seen on the low side of the hole, right at the centralizer in the non-washed-out hole section.

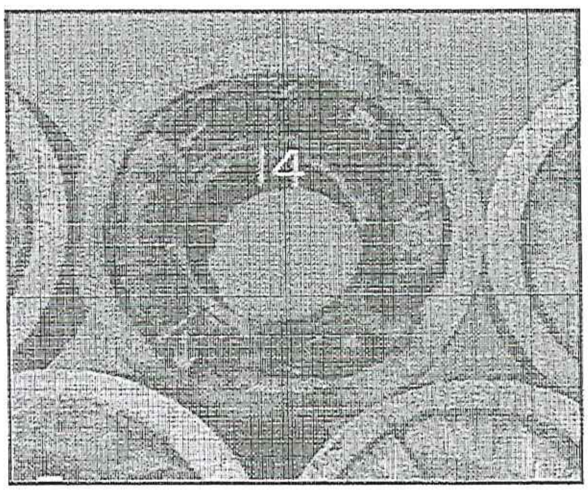


Figure 18—Swirl-inducing Centralizer in an Inclined, Non-enlarged Hole with Permeability

From the previous discussion, it is concluded that swirl alone may not completely remove the dehydrated mud and solids beds in the hole. Mobility of partially dehydrated mud layers has been measured in large-scale experiments. As mentioned, the mobility of the dehydrated mud layer can be orders of magnitude lower than that of the non dehydrated mud. The dehydrated mud layer is removed when the flowing fluid applies a shear stress that is higher than the resistance at the fluid-dehydrated mud interface. The turning of a fluid by swirl-inducing devices does not necessarily mean that it applies the needed stress. Much of the energy needed to remove the films is lost along with the fluid that bypasses the SID on the wide part of the hole, particularly when the device is not well centralized.

As indicated, the benefit of a SID has shown to be confined to an area near the device. Bow-spring centralizers have also been found to improve mud cleaning in the very near proximity of the devices. Crook's experiments in pipes (SPE 14198, 1985) showed that bow-spring centralizers improve mud displacement in inclined holes, particularly near the centralizers (see Figure 19). Bow spring centralizers with fins (see Figure 20) are available that induce flow disturbances at and near the centralizer.

3.9 Centralizer Installation

Throughout the industry, concerns have been expressed regarding every possible type of centralizer installation. These concerns include installations over casing collars, fears of pushing the centralizers in the hole, the ability of the limit clamps (stop collars) to hold the centralizers in place, etc.

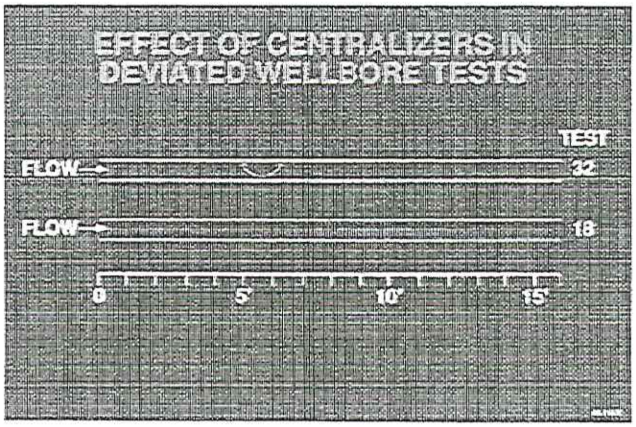


Figure 19—Effect of Bow-spring Centralizers in Proximity of the Device (After Crook, 1985)

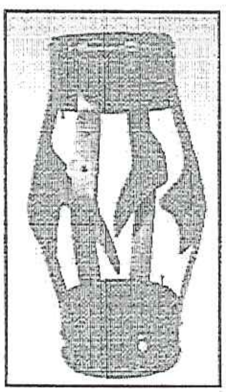


Figure 20—Example of Bow Centralizer with Fins

If high quality centralizers and high quality stop collars are used they are much less likely to be damaged going in the hole and during pipe movement. The correct installation of the centralizers is critical. For example, there are many applications where installation of the centralizers over casing collars is perfectly acceptable. However, there are situations where this practice should be avoided. Compatibility of the centralizer and stop collar or casing collar must be checked and evaluated against well conditions and desired performance in the well.

To help optimize mud displacement, centralizers must be properly installed on the casing. When installing centralizers for rotation of the casing, it is important to ensure the casing will be free to rotate inside the installed centralizer. Large clamp screws in the stop collars should be avoided since they may tend to "lock" the centralizer onto the collar when attempting to rotate the casing. Figures 21 and 22 illustrate possible centralizer installations for casing rotation. When casing will be rotated, it is important to place the centralizers over stop collars, over the casing collars (if allowed by well conditions), or between stop collars, so that centralizers can allow rotation of the casing without having to move after the casing is in place.

If the casing is to be reciprocated, it is again important to have the centralizers static while the pipe is being moved. For this application, it is best to "float" the centralizers between casing collars or stop collars, and to limit the reciprocation stroke to lengths such that the centralizers will not be forced to move once the casing is in place.

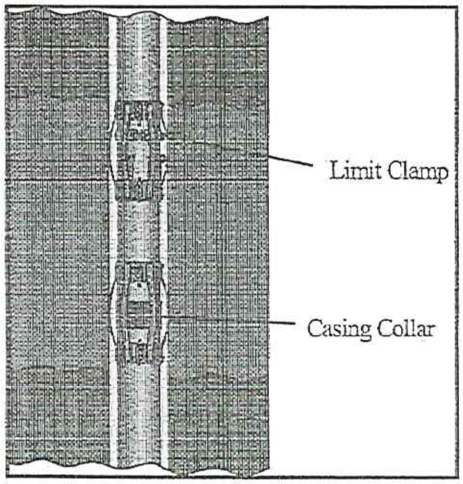


Figure 21—Centralizer Installations for Casing Rotation

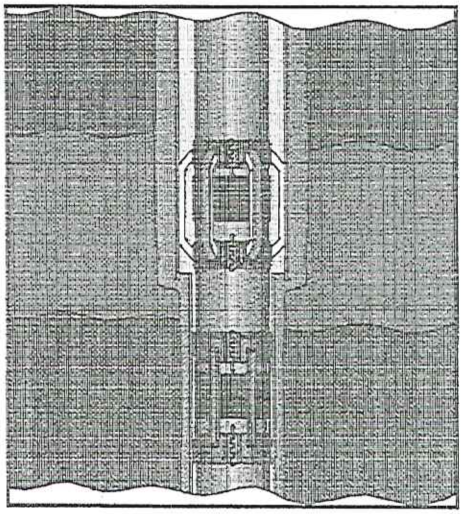


Figure 22—A Type of Rigid Centralizer Installed for Casing Rotation

3.9.1 Centralizer Installation Methods (Bow-spring and Rigid Types)

There are four possible installation methods for centralizers:

- Case 1: over stop collars, for casing rotation, often not used for reciprocation, not for close tolerances, will result in centralizer being "pulled" into the wellbore, easy to install on the racks;
- Case 2: between stop collars, for rotation or reciprocation, for close tolerance situations, easy to install on the racks, will result in the centralizer being pushed into the hole;
- Case 3: between couplings and stop collars, for rotation or reciprocation, for close tolerances, will result in the centralizer being pushed into the hole;
- Case 4: over casing couplings, for rotation, not for close tolerances, reduces annular flow area, cannot be installed on the pipe rack.

NOTE This installation concentrates lateral loads at the couplings.

Figure 23 further illustrates the different installation methods.

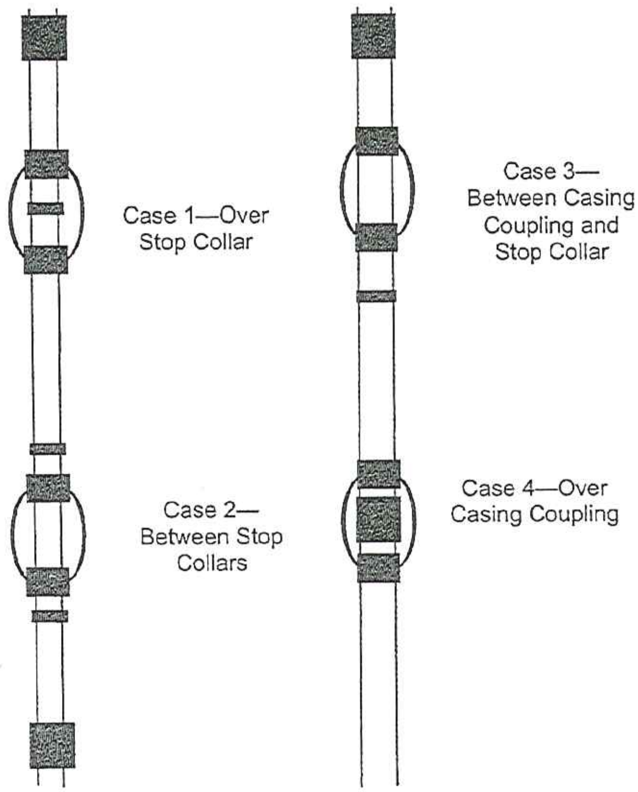


Figure 23—Four Centralizer Installation Patterns

3.10 Use of Dissimilar Materials: Casing-centralizer

Some in the industry have expressed concern regarding the use of centralizers constructed from metals other than iron (steel). An example of these type centralizers are solids and/or rigids made from aluminum and/or zinc. The concern is based on the potential for long-term corrosion effects of the casing string generated by the use of dissimilar materials.

While some military and state codes restrict or ban the use of dissimilar metals with concrete, no studies have been conducted to date to test if dissimilar metals and cement are cause for concern in an oil well context. It should also be noted that zinc and aluminum are commonly used for the protection of steel in pre-stressed concrete structures.

3.11 Centralizer-formation Interactions

3.11.1 Discussion

In all situations where centralizers are run, it is assumed the formations will have enough strength to support the load of the centralizer. This is the normal assumption even when centralizing the casing across shallow and poorly consolidated formations. Thus, the possibility of some formations not being competent enough to withstand the loads is normally not considered. The potential exists that some combination of centralizer-formation may result in the centralizers penetrating into the formation (embedment), with the consequences of possible damage to the centralizers, loss of desired standoff and even sticking the casing. Unfortunately, very little research has been reported by the industry on this important topic. A visualization of potential embedment of centralizers into formations is given in Figure 24.

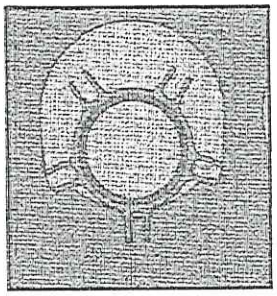


Figure 24—Visualization of a Centralizer Embedded into the Formation

3.11.2 Formation Strength

So called "weak" formations, because they are under confining stresses downhole, tend to be more competent than frequently assumed from the drilling data. An illustration from a simple lab test is given below.

The graph in Figure 25 shows results taken when unconsolidated sand was compression-tested under various hydrostatic loadings. At zero pressure, the sand had no compressive strength (completely unconsolidated). As the pressure was increased, the effective compressive strength of the sand also increased. The tests were conducted in such a way that a filter cake was formed on the sand. During the tests, the filter cake was preserved as much as possible. These tests suggest that poorly consolidated/cemented sandstone can exhibit a level of in-situ compressive strength under differential fluid pressure. This would tend to reduce the potential for centralizer embedment.

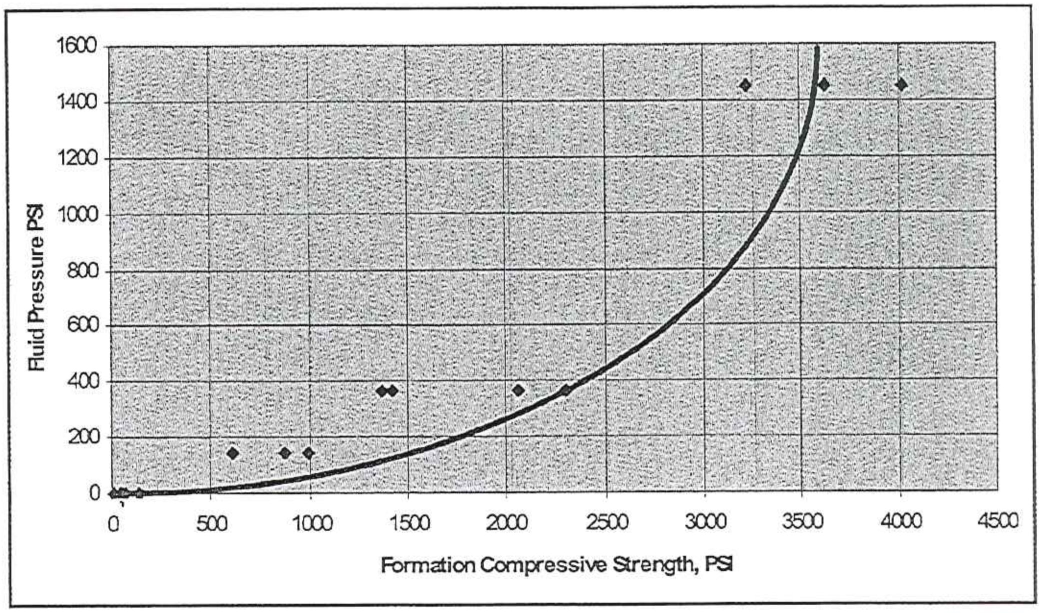


Figure 25—Testing of Unconsolidated Sand Under Hydrostatic Pressure

3.11.3 Centralizer Embedment

The likelihood of a centralizer becoming embedded is a function of the following.

- The hole inclination, presence of doglegs, ledges, etc.
- The formation type, strength and degree of consolidation.
- The centralizer type and performance.
- The shape and the surface area of contact. Different bows, for example, flatten in different ways.
- Solid and rigid centralizers contact the formation in different ways with various areas of contact.
- The normal forces that are generated.
- Other factors including mud type, mud cake, mud lubricity, differential pressure, etc.

A rubbleized or totally unconsolidated formation likely will respond poorly to the centralizer's forces, and therefore, it would be expected that the centralizer would have high potential for embedment. In contrast, consolidated/cemented formations should respond better to the normal forces and mechanical shear exerted by the centralizers.

3.11.4 An Approximation to Determine Formation Strength Needed to Prevent Centralizer Embedment

Intuitively, the downhole compressive strength of the formation must be higher than the expected normal forces per unit area at the centralizer-formation contact area. Likewise, the downhole shear strength of the formation must be higher than the expected running (drag) forces over the contact area.

Example:

- Formation is consolidated sand.
- Formation downhole compressive strength is ± 5,500 psi.
- Across a given area, local normal forces were estimated (using a centralizer placement computer program) to be ± 1,800 lbf.
- Local running (drag) forces were estimated to be ± 600 lbf across the same area.
- Assume shear strength of the formation is ± 12 % of the compressive strength.
- Assume for simplicity, 1-in.^{2} total contact area, centralizer-formation.
- Will the centralizers embed?

Calculations:

1. The normal forces/in.^{2} (1,800 lbf/1 in.^{2}) are less than the compressive strength of the formation.
2. The projected shear stress of the formation is: $0.12 \times 5{,}500 = 660$ lbf/in.^{2}. The drag force/contact area = 600 lbf/in.^{2}. Therefore, the shear stress of the formation is greater than the drag force/contact area.

Conclusion: No centralizer embedment is predicted for the example by this method.

NOTE The above method is an approximation.

3.12 Stop Collar and Integral Collar Holding Forces

When one considers the complex subject of casing centralization, stop collars and their holding forces are often neglected. Stop collars are extremely important to the success of the centralization effort. If the collars are damaged or if they move, even the running of the casing in the hole can be jeopardized (formation of centralizer "nests").

When hole conditions allow, centralizers are often placed over casing collars. This type of installation eliminates stop collar concerns and may be used in both casing rotation or reciprocation applications. This technique may not be appropriate for use in tight annuli, where the centralizer may bend if it flexes against the shoulder of a collar. The compatibility of centralizers with casing collars must be verified.

Different hole configurations require different stop collar designs. The stop collars must provide adequate holding force. Several experiments have been conducted comparing the holding forces of different collar types. Large differences have been reported among the different designs. Table 3 gives the results of tests conducted in 1992.

In the tests, collars with the set screws and with the "dogs" gave the larger holding forces. Tests have also been conducted with epoxy applied between the stop collar and the pipe. Those tests indicated the holding force of a given collar can be increased, but the collars should not be painted to allow direct bonding of the epoxy to the clean (no oil films) metal.

The example data indicates that, like centralizers, stop collars should also be tested to measure their performance characteristics. The previously mentioned ISO/API documents provide a method to test the holding and slippage forces of stop collars. Depth of the gouge (indentation) on the casing after the collar moves should be measured. It is critical that the holding force tests be conducted using the same grade of pipe to be used in the actual well, as this will have an impact on the results. No stop collar or holding device will function if improperly installed. Manufacturer's installation procedures must be followed precisely for stop collars to hold centralizers in place as desired. Some centralizers have built-in holding mechanisms. These should also be applied according to the manufacturer's recommendations.

Table 3—Holding Forces of Different Type Stop Collars

9 5/8-in. Stop Collar Test[1] Results J-55 Casing			
Limit Device	**Type of Installation**	**Maximum Holding Force (lbf)**	**Average Depth of Casing Score (in.)**
Friction grip	Hinged with nut and bolt tightening	5,075	None
		8,400	None
6 Dogs	Hinged with nut and bolt tightening	34,250	0.037
		23,250	0.026
18 Dogs	Hinged with hammer clamping device	18,850	0.016
		15,500	0.011
6 Hammer-lock slips	Hinged	16,000	0.007
		17,400	0.007
6 Set screws	Slip-on	19,080	0.016
		25,000	0.023
8 Set screws	Hinged	15,500	0.013
		14,000	0.013
12 Set screws	Slip-on	17,650	0.013
		16,900	0.012

[1]Average of two tests performed on each type of stop collar

3.13 Centralizer Quality Control

Quality control of centralizers should include: properties of the construction materials, welds, type and properties of set screws and hinges, hinge pins, length ID/OD of the centralizer, storage and handling, etc. Manufacturers quality control program should be defined and verifiable and made available to the purchaser upon request.

3.14 Effect of Expansion Coefficient of the Stop Collar

If stop collar material is different from steel, the possibility exists that under downhole temperatures, the original (surface) holding force of the stop collar or integral device may vary due to expansion of the collar. Therefore, it is important to know the expansion coefficients of stop collar materials other than steel, to estimate possible changes of the holding forces under downhole conditions. This is particularly important since the holding force tests for stop collars as per API/ISO documents are conducted at room temperature.

3.15 Potential Impact of Centralizers on Casing String Stiffness

The spacing of centralizers as well as the type chosen can have an impact on the lateral loads on the casing and therefore the drag forces. The equations presented in the API/ISO documents for calculating lateral loads do not take into account the stiffness of the casing string or the tortuosity of the wellbore path between survey points. If the wellbore is relatively straight with low dogleg severity the stiffness of the casing will have little effect on the lateral loads generated. However, severe doglegs can induce high lateral loads (and therefore increased drag) from bending moments in proportion to the casing string stiffness, in addition to the tensional component of the lateral load produced by a geometric obstruction within the wellbore.

Stiffness increases with increasing casing diameter and wall thickness. Centralizers have the effect of increasing the apparent casing diameter where contact is made with the wellbore, causing the casing to more closely follow the curvature of the wellbore. Increased curvature of the casing results in higher bending moments of the casing and higher lateral loads at the centralizers. If centralizers are spaced too closely, and if there is little clearance between the centralizer's rigid outside diameter and the borehole diameter, the casing may be difficult to run through changing wellbore curvatures. Examples of this situation in a wellbore with a short offset length are illustrated in Figure 26. Whereas casing with no centralizers may run through this particular short offset section without bending, rigid centralizers may force the casing to more closely follow the wellbore curvature. By spacing the rigid centralizers further apart as illustrated, the casing may not follow the wellbore path as closely and bending moments in the casing may be reduced. Bow-spring centralizers flex in proportion to the lateral load, allowing less casing curvature and therefore less bending moments when running through offset sections. On the other hand, bow-spring centralizers may not provide adequate standoff across hole sections of high lateral loads because of deflection of the bows.

The length and method of attachment of rigid centralizers can also impact the effective stiffness of the casing string. If the rigid centralizer is secured to the casing with no clearance over its length, the stiffness of the casing increases. Increased stiffness results in higher lateral loads in a curved wellbore. Clearance between the rigid centralizer and the casing allows the casing to bend in proportion to this clearance without interference. It also has the effect of reducing the standoff dimension. An increase in the length of a rigid centralizer reduces the allowable bending of the casing without interference from the centralizer. The stiffness of the casing section is increased after centralizer interference is established.

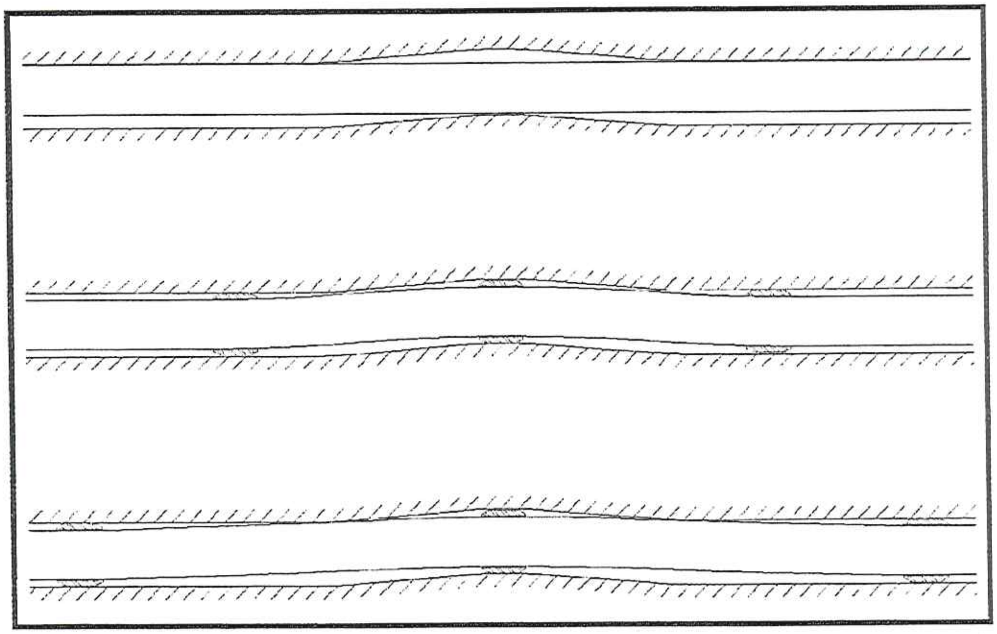


Figure 26—Impact of Centralizers on Casing String Stiffness

3.16 Compatibility of the Centralizers with Wellbore Fluids

Centralizer and stop collar construction materials must be fully compatible with wellbore fluids (drilling fluid and cementing spacers, flushes, and slurries) under downhole conditions. For materials other than steel, it is important for the user to have available from the manufacturer data that shows that deleterious effects (i.e. degradation, softening, decomposition, etc.) are not possible due to interaction of the material with the wellbore fluids.

3.17 Thermal Stability of the Centralizer Materials

For centralizers and stop collars made from non-metallic materials, the data on thermal stability of such materials at downhole conditions of temperature and pressure should be available to the user to ensure that the integrity of the devices is preserved while running in the hole, during cementing, and throughout the life of the well. Compressive and tensile strength tests at temperatures ranging from ambient to elevated temperatures (e.g. 400 °F) or to the temperature at which the mechanical properties fall below useful limits should be considered. ASTM D4065, *Standard Practice for Determining and Reporting Dynamic Mechanical Properties of Plastics,* may be used as a means of determining the thermal stability of non-metallic centralizers.

3.18 Potential Carbon Steel and Chrome Interaction

No information or data has been made available to the Task Group concerning any possible harmful effects due to the interaction between carbon steel casing hardware and high chrome steel casing. However, the compatibility between carbon steel casing hardware and high chrome steel casing should be verified before use.

3.19 Potential Generation of Gases from Materials Under Downhole Conditions

To date, there are no indications of harmful gas-generating effects associated with the use of non-steel centralizers when in contact with cement. While the potential exists for chemical reactions of the cement with, for example, zinc or aluminum, the centralizer surface areas exposed to the cement are normally not sufficient to generate substantial volumes of gas. Furthermore, possible generation of small amounts of gas is normally not considered a problem under the high hydrostatic pressures encountered in typical wells. Finally, once the cement is set, the amount of gas which can be produced is very small and of little significance.

3.20 Centralizer Wear (Durability) During Running in the Hole

Published and field data indicate that friction coefficients in drilling operations depend heavily on the type of drilling mud (oil-or water-based) and on the mud additives (such as lubricants). Centralizers made from "soft" materials may generate lower frictional forces; however the potential wear of the "soft" centralizers as they are run downhole, particularly in extended reach applications, may reduce their ability to produce desired levels of standoff.

IADC/SPE 47804 gives an example of data generated using the pin-on-disk method, showing a comparison of the wear of several construction materials: steel, aluminum, and an aluminum-zinc alloy. The data set (Table 4) for this particular test shows steel resisted wear much better than other materials tested, suggesting a better chance for this material to get to bottom without much wear (potential preservation of the desired standoff).

Table 4—Wear Measurements in Micrometers

Disk Material	Specimens[1]		
	Steel	Aluminum-Zinc	Aluminum
Steel	4.5	31	135
Sandstone	7.8	45.4	357

[1]Steel = Hot rolled steel; 63.8 ksi max tensile, aluminum-zinc = $ZnAl_{14}$, aluminum = $AlSi_9Cu_3$

It must be noted that this data is specific to the particular test device, fluid being used, rotational speed, test materials, etc.

In cases where new technology is being offered to the marketplace it is imperative that operators obtain detailed information and data documenting the characteristics of the centralizer, its construction materials and its performance.