

Centralizer Placement and Stop-collar Testing

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Centralizer Placement and Stop-collar Testing

1 Scope

This standard provides calculations for determining centralizer spacing, based on centralizer performance and desired standoff, in deviated and dogleg holes in wells for the petroleum and natural gas industries. It also provides a procedure for testing stop-collars and reporting test results.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Specification 5CT, *Casing and Tubing*

ISO 11960 ¹, *Petroleum and natural gas industries—Steel pipes for use as casing or tubing for wells*

3 Terms and Definitions, Symbols and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply.

3.1.1

bow-spring centralizer

An apparatus comprised of a plurality of bow-shaped springs biased outwardly from a tubular body, the outside diameter (OD) of which can vary under a change in applied load, and connected by two end collars, which is placed on the outside of a tubular (e.g. casing or tubing) and used to centralize the tubular in a wellbore.

3.1.2

bow-spring centralizer sub

A bow-spring centralizer installed on a tubular body having an integral holding method where the tubular body becomes its own section of the casing string.

3.1.3

holding device

Device employed to limit the axial movement of the stop-collar or bow-spring centralizer on the casing.

EXAMPLE Set screws, nails, machined tubular, mechanical dogs, epoxy resins, or machined features (integral).

¹ International Organization for Standardization, Chemin de Blandonnet 8, CP 401, 1214 Vernier, Geneva, Switzerland, www.iso.org.

3.1.4**holding force**

Force required to initiate slippage of a stop-collar on the casing.

3.1.5**hole size**

Diameter of the wellbore at the intended centralizer setting depth.

NOTE This includes setting depth in cased hole, open hole, or restriction(s).

3.1.6**restoring force**

Normal force exerted by a bow-spring centralizer against the casing to keep it away from the wellbore wall, and equal to the load force required to provide the deflection of the bow in given conditions and installation methods.

3.1.7**rigid centralizer**

An apparatus with bow, blades, or bars whose OD does not vary under an applied load change.

3.1.8**running force**

Average force required to move a bow-spring centralizer through a specified wellbore diameter in given conditions and installation methods.

3.1.9**sag point**

Point where the casing deflection is at a maximum.

NOTE Casing that is supported at two points will tend to sag between the support points; this sag is called the casing sag or casing deflection.

3.1.10**slippage force range**

Range of forces required to continue to move a stop-collar after the holding force has been overcome.

3.1.11**solid centralizer**

An apparatus with fins or blades whose OD does not vary under an applied load change.

NOTE These centralizers have solid bodies and solid blades.

3.1.12**standoff**

Smallest distance between the OD of the casing and the wellbore.

3.1.13**standoff ratio*****SOR***

Ratio of standoff to annular clearance, expressed as a percentage.

NOTE 1 In the field, standoff ratio is commonly referred to as "standoff."

NOTE 2 Standoff ratio is defined as a variable, i.e. *SOR*.

3.1.14**starting force**

Maximum force required to insert a bow-spring centralizer into a specified wellbore diameter in given conditions and installation methods.

3.1.15**stop-collar**

Device attached to the casing to limit axial movement of a casing bow-spring centralizer.

NOTE Can be either an independent piece of equipment or integral with the bow-spring centralizer.

3.2 Symbols

For the purposes of this document, the following symbols are used.

D_H	wellbore diameter (open-hole or outer-casing internal diameter), expressed in meters (inches)
E	modulus of elasticity of the casing, expressed in pascals (N/m ²) (pounds-force per square inch)
e_c	standoff at the centralizer, expressed in meters (inches)
e_{max}	annular clearance for concentric casing, expressed in meters (inches)
e_s	standoff at the sag point, expressed in meters (inches)
F_l	lateral load, expressed in newtons (pounds-force)
$F_{l,dp}$	total lateral load in the dogleg plane, expressed in newtons (pounds-force)
$F_{l,p}$	total lateral load perpendicular to the dogleg plane, expressed in newtons (pounds-force)
F_{l-3D}	total lateral load of a length of casing between two adjacent centralizers (l_c) in the 3D dogleg plane, expressed in newtons (pounds-force)
F_t	axial tension force below the centralizer, expressed in newtons (pounds-force)
ΔF_t	incremental axial tension force, expressed in newtons (pounds-force)
f_b	buoyancy factor (dimensionless)
f_c	lateral load force, expressed in newtons (pounds-force)
f_w	wellbore deflection restriction, expressed in meters (inches)
I	moment of inertia of the casing, expressed in m ⁴ (in. ⁴)
ID_C	inside diameter of the casing, expressed in meters (inches)
ID_c	inside diameter of the solid or rigid centralizer, expressed in meters (inches)

L	length of curved wellbore section, expressed in meters (inches)
l_c	distance between two adjacent centralizers, expressed in meters (inches)
M	resultant of the internal moment (torque and drag forces), expressed in newtons (pounds-force)
M_b	torsional load, expressed in newtons (pounds-force)
m	moment due to the contact forces (drag and torque), expressed in newtons (pounds-force)
OD_C	outside casing diameter, expressed in meters (inches)
OD_c	outside diameter of the solid or rigid centralizer blades, expressed in meters (inches)
P	pipe bending lateral contact force, expressed in newtons (pounds-force per square inch)
R	wellbore curvature radius, expressed in meters (inches)
r	wellbore clearance, expressed in meters (inches)
SOR	standoff ratio, expressed as a percentage
SOR_c	standoff ratio at the centralizers, expressed as a percentage
SOR_m	minimum standoff ratio, expressed as a percentage
SOR_s	standoff ratio at the sag point, expressed as a percentage
s	measured depth (MD) along the wellbore axis, expressed in meters (inches)
T	axial load force, expressed in newtons (pounds-force per square inches)
t	direction of the tangent to the wellbore curvature (see 9.4.5)
u	casing displacement, expressed in meters per second (inches per second)
W	unit weight of casing in air, expressed in newtons per meter (pounds-force per inch)
W_b	unit buoyed weight of the casing, expressed in newtons per meter (pounds-force per inch)
w	casing rotation, expressed in radians per second
β	total angle change between two adjacent centralizers, expressed in degrees
ΔF_t	is the incremental axial tension force of a length of casing on a length above it, expressed in newtons (pounds-force)
γ_o	angle between the gravity vector and the binormal of the wellbore, expressed in degrees
γ_n	angle between the gravity vector and the principal normal of the wellbore, expressed in degrees
δ	casing eccentricity (or bow-spring centralizer deflection), expressed in meters (inches)

$\delta_{\max}$	maximum deflection of the casing between two (2) centralizers, expressed in meters (inches)
θ	wellbore inclination angle, expressed in degrees
θ_1	wellbore inclination angle at the top of the upper centralizer (i.e. top of l_c), expressed in degrees
θ_2	wellbore inclination angle at the bottom of the lower centralizer (i.e. bottom of l_c), expressed in degrees
κ	wellbore curvature, expressed in radians per meter
μ	axial load factor (see 9.4.3)
μ_s	sliding friction coefficient, expressed as a decimal fraction
ρ_e	density of the fluid outside the casing, expressed in kilograms per cubic meter (pound-mass per gallon)
ρ_i	density of the fluid inside the casing, expressed in kilograms per cubic meter (pound-mass per gallon)
ρ_s	density of the casing material, expressed in kilograms per cubic meter (pound-mass per gallon)
ϕ_1	wellbore azimuth angle at the top of the upper centralizer (i.e. top of l_c), expressed in degrees
ϕ_2	wellbore azimuth angle at the bottom of the lower centralizer (i.e. bottom of l_c), expressed in degrees

3.3 Abbreviations

For the purposes of this document, the following abbreviations are used.

DLS	dogleg severity
DwC	drilling-with-casing
ECD	equivalent circulating density
ERD	extended reach drilling
ID	inside diameter
MD	measured depth
OD	outside diameter
RIH	running in hole
TD	total depth

4 Methods for Estimating Centralizer Placement

4.1 Benefits of Centralization

Casing and liners should be centralized in the wellbore for the following reasons:

- a) to help get the casing to bottom (this includes reduction of the potential for sticking of the string, and delaying the onset of buckling);
- b) to help pull casing out of the hole;
- c) to help rotate and reciprocate casing during drilling fluid conditioning and the cementing operation;
- d) to provide an optimal path for fluid flow during drilling fluid conditioning and cementing allowing for effective drilling fluid 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 placement, particularly in narrow annuli. Therefore, a good centralization program should aim for adequate levels of standoff, which produces improved drilling fluid removal, particularly across critical areas of the wellbore, i.e. those areas where isolation is required. It should be imperative that the user investigates the standoff at all points, especially between the centralizers, and at different points in time while running casing and during the cementing operation.

4.2 Modeling Considerations

The equations presented in Section 9 are based on certain assumptions and are considered sufficiently accurate for general use. The equations are based on what is commonly referred to as the soft-string model. More specific calculations based on complete wellbore data may be available but are beyond the scope of this document.

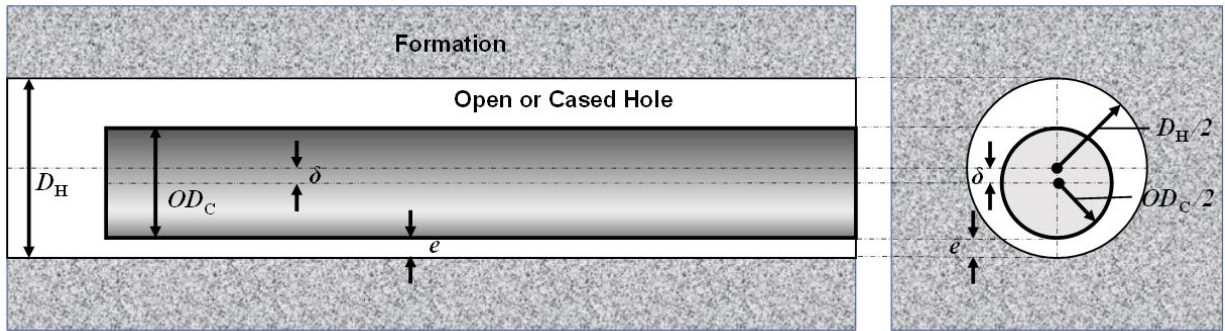
There is no recommendation or requirement for a specific standoff ratio (*SOR*) for casing centralization. The *SOR* of 67 % is used in API 10D for the purpose of setting a minimum standard for performance of casing bow-spring centralizers only. This number is used only in API 10D for bow-spring-type centralizers and deals with the minimum force for each size of centralizer at that standoff. The 67 % *SOR* is not intended to represent the minimum acceptable amount of standoff required to obtain successful centralization of the casing. The user is encouraged to apply the *SOR* required for specific well conditions based on well requirements and sound engineering judgement.

A minor change in inclination and/or azimuth, with the string of casing hanging below it, affects the standoff and the requirements for centralizer placement.

The lateral load (force) on a centralizer is composed of two components. The first is the weight component of the section of pipe supported by the centralizer, and the second is the tension component exerted by the pipe hanging below the centralizer.

4.3 Definition of Standoff

Standoff is defined as the smallest distance between the outside diameter (OD) of the casing and the wellbore. The *SOR* (standoff ratio) is defined as the ratio of standoff to the annular clearance for concentric casing expressed as a percentage (%). Annular clearance for concentric casing is the wellbore diameter minus the casing OD divided by two (see 9.2). Figure 1 illustrates standoff and annular clearance.

**Key**

OD_C	Outside casing diameter	δ	Casing eccentricity
D_H	Wellbore diameter (open-hole or outer casing inside diameter)	e	Standoff

Figure 1—Definition of Casing Standoff**4.4 Casing Centralization**

Casing centralization often requires centralizers to keep the casing away from the wellbore and/or from the cased sections of the well. Considerations for selecting and placing centralizers should include following parameters.

- Centralizer types, quantities, and installation mode to allow the casing to be run to total depth (TD) of wellbore with minimum problems.
- 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.
- Provide casing centralization over the target intervals (including at points between the centralizers).
- Ability of the formation(s) to provide enough support for the tools to minimize centralizer embedment.
- Presence of a cuttings bed may decrease the annular gap on the low side of the hole.
- Presence of a cuttings bed may increase drag forces, hindering casing running.
- Allow for planned and contingency casing movement.
- Wellbore quality (tortuosity, washouts, hole enlargement, keyseats, tight spots, collapse, hole geometry, hole cleaning, etc.).
- Flow-by area and equivalent circulating density (ECD) limitations.
- Cementing objectives.
- Downhole environment, material compatibility (casing, centralizer, stop-collar, set screws), longevity.
- Logistics (transportation, storage, etc.).
- Installation location and equipment limitations.

5 Centralizer Types

5.1 General

The industry has developed the following main types of centralizers: bow-spring, rigid, solid, integral, bonded.

5.2 Bow-Spring Centralizer

A bow-spring centralizer is composed of flexible spring bows connected by two end collars (see Figure 2). By design, the bows are flexible to allow passage of the centralizer through restrictions yet continue to provide standoff. The springs come in various shapes and dimensions. The OD of a bow-spring centralizer can be larger or equal to the nominal hole (bit) diameter. A larger diameter centralizer can improve standoff in over-gauged hole sections.

Bow-spring centralizers are commonly available in welded, non-welded, or single-piece construction. Welded and non-welded centralizers are available in hinged or slip-on designs. Single-piece construction centralizers are typically available in slip-on designs. Bow-spring centralizers are sometimes referred to as imperial centralizers or conventional bow-spring centralizers.



Figure 2—Example of a Bow-spring Centralizer

5.3 Double Bow-spring Centralizer

Double bow-spring centralizers incorporate bows with a reduced bow diameter between the centralizer collars (see Figure 3). Double bow-spring centralizers have a maximum OD less than conventional bow-spring centralizers, resulting in lower starting and running forces without sacrificing restoring forces. The rigid OD of double bow-spring centralizers is generally larger than in conventional centralizers, limiting their ability to pass through restrictions or tight areas. Bow geometry also impacts available installation method, location, and placement. Double bow-spring centralizers may also be considered as semi-rigid type, as discussed in Section 6.

They are available in similar construction and design options as described above for bow-spring centralizers. Double bow-spring centralizers are sometimes referred to as tandem-rise, dual-bow, or dual-contact spring centralizers.



Figure 3—Example of a Double Bow-spring Centralizer

5.4 Rigid, Semi-rigid, and Solid Centralizers

5.4.1 Rigid Centralizer

Rigid centralizers incorporate blades or fins with minimum or no flexibility connected by a single or discontinuous body (see Figure 4).

5.4.2 Semi-rigid Centralizer

Semi-rigid centralizers incorporate solid or hollow blades or fins that are not designed to flex and, therefore, tend to maintain a constant centralizer 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 semi-rigid centralizers are available from manufacturers (see Figure 4).



Figure 4—Examples of Rigid (left) and Semi-rigid (right) Centralizers

Semi-rigid centralizers are available in welded, non-welded, or single-piece construction. Welded and non-welded are also available in hinged or slip-on designs. Semi-rigid centralizers can be manufactured with straight or spiral blades or fins.

Double bow-spring centralizers (Figure 3) are sometimes considered as semi-rigid centralizers. This is because after a small deflection, the bows essentially become rigid.

5.4.3 Solid Centralizer

Solid centralizers are manufactured with completely non-flexible solid blades or fins. They do not flex in hole restrictions. Examples of this type of centralizer include those made of steel and low-friction materials, such as aluminum, zinc alloy, composites, and polymers (see Figure 5). Blades are available in either straight or spiraled configuration.

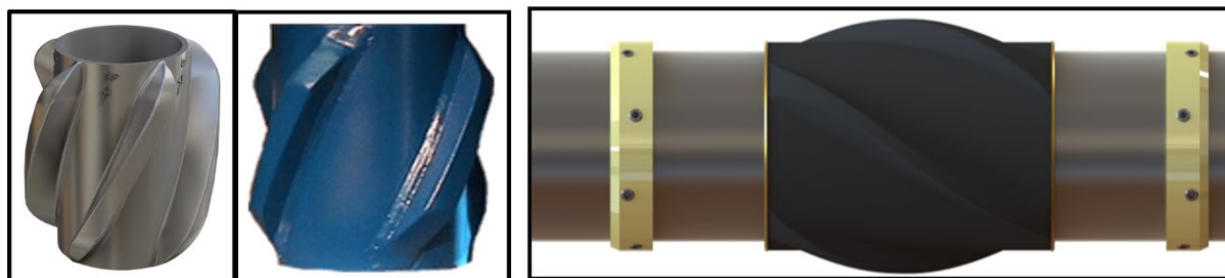


Figure 5—Examples of Solid Centralizers: Low-friction Material and Steel (left), Polymer (right)

Solid centralizers are available in welded or single-piece construction. Welded are also available in hinged or slip-on designs. Solid centralizers can be manufactured with straight or spiral blades or fins.

Roller centralizers are solid centralizers that incorporate rollers to reduce the drag and torque. Designs of roller centralizers are available for running the casing and for allowing rotation of the string. Figure 6 shows a running-rotating combination. Roller centralizers can assist running the casing in extended-reach wells.



Figure 6—Example of Roller Centralizer for Running and Rotating of the Casing

5.5 Integral Centralizer

Integral centralizers are made up as part of the casing itself (like pup joints). Figure 7 illustrates this type of centralizer. Integral centralizers are mainly used in reduced annular clearance applications, such as deepwater wells. The centralizer blades or fins are commonly machined features on the centralizer sub, eliminating the possibility of slippage. They are also offered with bow-springs for under-reamed applications. Integral bow-spring centralizers are available in rotating and nonrotating designs. Integral centralizers are also referred to as centralizer subs.



Figure 7—Examples of Integral Centralizers

5.6 Bonded Centralizer

Bonded centralizers are formed and bonded directly onto the pipe. The centralizers are made from a variety of composite materials. Figure 8 illustrates an example of this type of centralizer. Bonded centralizers are commonly used in slim-type well configurations and extended reach drilling (ERD) wells.

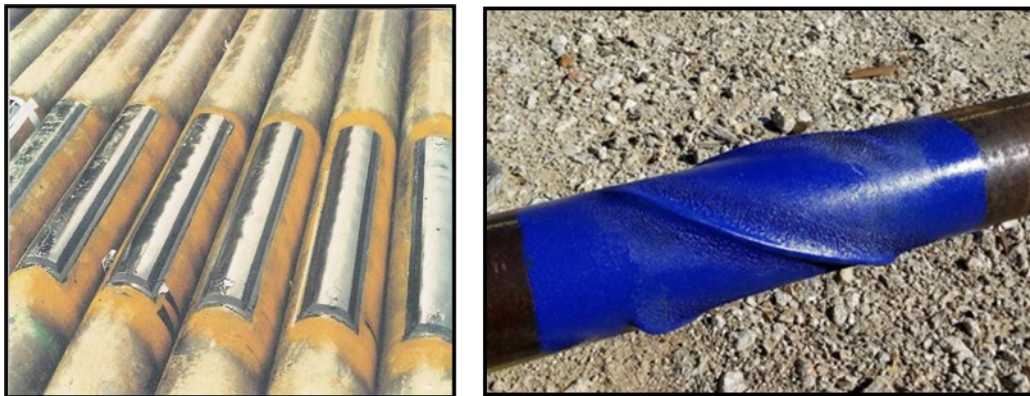


Figure 8—Examples of Centralizers Bonded Directly onto the Pipe

6 Advantages and Limitations of Centralizer Types

6.1 General

This section describes the advantages and limitations of each centralizer type.

6.2 Bow-spring Centralizer

6.2.1 Advantages

Recognized advantages of bow-spring centralizers include the following.

- Ability (flexibility) of adjusting to varying hole sizes, including passing through smaller diameters (such as in wellheads and casing running equipment). This allows for maintaining standoff even in irregular hole sizes.
- Can increase the maximum achievable standoff in over-gauge hole.
- As bow-spring centralizers are typically run at gauge or over-gauge, they can provide better standoff than rigid centralizers if they have sufficient restoring force.
- With hinged centralizers:
 - may allow installation over casing couplings and external upset connections (associated benefits and risks are discussed later in the document);
 - greater flexibility for installation, such as multi-joint stands;
 - efficiency in transportation and storage.
- With single-piece construction:
 - minimizing a potential weak point;
 - low profile design allowing running through tighter annular clearances.
- Double bow-spring centralizers provide higher restoring forces with minimum increases in starting and running forces.
- May provide larger flow-by area compared to solid body centralizers.

6.2.2 Limitations

For bow-spring centralizers, their limitations include the following.

- These centralizers generally exhibit starting and running forces.
- Require additional considerations (see Sections 7 and 8) when used in highly deviated and horizontal wells.
- If the centralizers become stuck or encounter excessive drag forces, they may break or the stop-collars may slip, potentially forming a “nest” of centralizers. This can lead to significant problems such as the casing getting stuck, damage to the blowout preventer (BOP) or wellhead, un-drillable debris at the bottom of the hole leading to potential sidetracks or loss of hole section, and other problems.
- These devices may not provide desired standoff under high lateral load conditions.
- Require additional considerations and preparation for transportation to avoid damage (when pre-installed offsite).

6.3 Rigid and Solid Centralizers

6.3.1 Advantages

Recognized advantages of rigid and solid centralizers include the following.