ABSTRACT

A downhole tool is disclosed for measuring wellbore geometry. The downhole tool may include a body with a bore extending at least partially therethrough. The body may include a radial recess. An arm may be movably coupled to the body at a first end portion of the arm. The arm may be within the radial recess in a retracted position and be pivotable in a radially-outward direction relative to the body to an expanded position. A measurement device coupled to the body may measure the pivoting motion of the arm. A piston coupled to the body may be movably coupled to a second end portion of the arm, and the piston may respond to changes in hydraulic pressure to pivot the arm between the retracted position and the expanded position.
TOOL FOR MEASURING WELLOBRE GEOMETRY

FIELD OF THE INVENTION

[0001] Embodiments described herein generally relate to downhole tools. More particularly, embodiments of the present disclosure relate to downhole tools for measuring a diameter or other geometry of a wellbore while performing drilling or remedial operations within a wellbore.

BACKGROUND INFORMATION

[0002] Wellbores drilled in subterranean formations, such as oilfields, often have irregular shapes. In particular, walls of the wellbore are not perfectly smooth, and the magnitude of such irregularities may be particularly great where the borehole traverses weak, highly stressed, or fractured rock. Wellbore shape and geometry can provide an indication of the mechanical stability of the wellbore, and knowing the wellbore shape and geometry can be useful in downhole operations such as drilling, reaming, producing, casing, and plugging.

[0003] The diameter of the wellbore is oftentimes measured by an ultrasonic measurement tool, which measures the diameter of the wellbore using acoustic pulses and echoes. On wireline tools with limited drilling or remedial tools, local diameter measurements may also be made with mechanical arms. By combining measurements at different angular orientations and depths, wellbore geometry may be mapped out in two-dimensional or three-dimensional space.

SUMMARY

[0004] Embodiments of the present disclosure may relate to a downhole tool for measuring wellbore geometry. An illustrative downhole tool may include a body with a bore extending fully or partially therethrough. An aperture may also extend radially through a portion of the body. An arm with opposing ends may have one end movably coupled to the body. The arm may pivot to move between retracted and expanded positions. In the retracted position, the arm may be within the aperture, and in the expanded position the arm may be at least partially radially outward relative to the body and aperture. A piston in the bore of the body may be coupled to the second end of the arm and may respond to hydraulic pressure to cause the arm to pivot and move between the retracted position and the expanded position.

[0005] In accordance with another embodiment, a tool for measuring geometry includes a body with a bore therein. A piston coupled to the body may move axially within the body when hydraulic pressure of fluid in the bore is increased. A spring gear assembly coupled to the piston may rotate when the piston moves between two positions. An arm coupled to the body and the spring gear assembly may move radially relative to the body upon rotation of the spring gear assembly, and a measuring device coupled to the arm may measure rotational or other movement of the arm.

[0006] An example embodiment for measuring a diameter of a wellbore while performing a downhole drilling or remedial operation may include increasing a pressure of a fluid within a bore of a body of a downhole tool in the wellbore. A piston may move axially in response to the increased pressure, and an arm movably coupled to the body may be pivoted radially-outward in response to axial movement of the piston. A measuring device coupled to the arm may sense the pivot-
FIG. 13 is a partial perspective view of a measurement device that may be used in the downhole tool shown in FIG. 10, according to one or more embodiments of the present disclosure.

FIG. 14 is cross-sectional view of a measurement device in a downhole tool, according to one or more embodiments of the present disclosure.

FIG. 15 is a partial perspective view of the measurement device shown in FIG. 14, according to one or more embodiments of the present disclosure.

FIG. 16 is a cross-sectional view of the downhole tool shown in FIG. 14, according to one or more embodiments of the present disclosure.

FIG. 17 is a schematic view of three magnets, each associated with a different measurement device, according to one or more embodiments of the present disclosure.

FIG. 18-1 is a cross-sectional view of a downhole tool in an inactive state with an arm assembly folded into a body of the downhole tool, according to one or more embodiments of the present disclosure.

FIG. 18-2 is a cross-sectional view of the downhole tool of FIG. 18-1 in an active state with the arm assembly folded into the body of the downhole tool due to contact with a wall of a wellbore, according to one or more embodiments of the present disclosure.

FIG. 18-3 is a cross-sectional view of the downhole tool of FIG. 18-3 in the active state with the arm assembly expanded radially-outward and into contact with the wall of the wellbore, according to one or more embodiments of the present disclosure.

FIG. 19-1 is a cross-sectional view of the downhole tool of FIG. 18-1 in the inactive state with arm assemblies folded into the body of the tool, according to one or more embodiments of the present disclosure.

FIG. 19-2 is a cross-sectional view of the downhole tool of FIG. 18-2 and FIG. 18-3 in the active state with two arm assemblies expanded radially-outward and into contact with a round wall of a wellbore, according to one or more embodiments of the present disclosure.

FIG. 19-3 is a cross-sectional view of the downhole tool of FIG. 18-2 and FIG. 18-3 in the active state with two arm assemblies expanded radially-outward and into contact with a non-round wall of a wellbore, according to one or more embodiments of the present disclosure.

FIG. 20 is a partial perspective view of a downhole tool prior to a measurement device being inserted into an aperture in a body of the downhole tool, according to one or more embodiments of the present disclosure.

FIG. 21 is a cross-sectional view of the downhole tool shown in FIG. 20, according to one or more embodiments of the present disclosure.

FIG. 22 is a cross-sectional view of the downhole tool shown in FIG. 20, with the measurement device being inserted into the aperture, according to one or more embodiments of the present disclosure.

FIG. 23 is a cross-sectional view of the downhole tool shown in FIG. 20, with the measurement device disposed within the aperture, according to one or more embodiments of the present disclosure.

FIG. 24 is a cross-sectional view of the downhole tool shown in FIG. 20, with the measurement device coupled to the body and within the aperture between the body and the mandrel, according to one or more embodiments of the present disclosure.

FIG. 25 shows a cross-section of a partial perspective view of the downhole tool shown in FIG. 24, according to one or more embodiments of the present disclosure.

DETAILED DESCRIPTION

Some embodiments described herein generally relate to downhole tools. More particularly, some embodiments of the present disclosure relate to downhole tools for measuring a diameter or other geometry of a wellbore while performing drilling or remedial operations within the wellbore.

FIG. 1 shows a side view of an illustrative downhole tool 100 within a wellbore 102. The illustrated downhole tool 100 may be used for measuring wellbore geometry, according to one or more embodiments of the present disclosure. More particularly, the downhole tool 100 may include a drilling caliper assembly that is configured to measure the diameter of the wellbore in real-time. As shown in FIG. 1, the downhole tool 100 may include a housing or body 110 having a first or upper end portion 114, and a second or lower end portion 116. The upper end portion 114 may be coupled to a drill string, bottomhole assembly (BHA) component, or other drilling tubular 120. For instance, the upper end portion 114 may include a threaded box or pin connector to be threadingly engaged with a corresponding pin or box connector of a drill string extending upward toward a surface of a wellbore. In the same or other embodiments, the lower end portion 116 may be coupled to a drill string, BHA component, or other drilling tubular 120. The lower end portion 116 may include a threaded connector (e.g., box or pin connector) for being connected to a corresponding component of a lower drill string, BHA components, or the like. In other embodiments, the upper end and/or lower end portions 114, 116 may have other types of connectors.

In accordance with some embodiments, the body 110 may have one or more openings, radial recesses, or apertures (three apertures 122 are shown in FIG. 1) formed therein that are circumferentially-offset from one another. The apertures 122 may be defined as openings in the body 110, which may be generally tubular. The apertures 122 may extend through a thickness of the body 110 and therefore may extend radially from the outer surface 118 of the body 110 to an interior bore or chamber of the body 110. The apertures 122 may also extend axially along a suitable length of the body 110.

In some embodiments, a caliper system 136 may be at least partially positioned within each aperture 122. In this particular embodiment, the caliper system 136 may include an arm assembly 140, a spring gear assembly 160, and a pin slot connector 180. The arm assembly 140 may include an arm 142 having a roller 144 coupled thereto. The pin slot connector 180 may be coupled to the arm 142 and the spring gear assembly 160 may be coupled to the pin slot connector 180. Although three (3) apertures 122 and caliper systems 136 are shown in FIG. 1, it should be appreciated by those having ordinary skill in the art, having the benefit of this disclosure, that there may be more or fewer than three (3) apertures 122 and/or caliper systems 136. For instance, there may be one (1), two (2), or four (4) or more apertures 122 and/or caliper systems 136. In a more particular embodiment, the number of apertures 122 and caliper systems 136 may range up to six (6), eight (8), ten (10), twelve (12), or more. Moreover, while the illustrated embodiment shows the apertures 122 and caliper systems 136 as being circumferentially offset at a common
axial position, other embodiments also contemplate apertures 122 and caliper systems 136 that are axially offset. For instance, a first set of one or more apertures 122 and caliper systems 136 may be located at a first axial position, and a second set of one or more apertures 122 and caliper systems 136 may be located at a second axial position. Such positioning may allow real-time evaluation of wellbore geometry at multiple axial positions. Optionally, the apertures 122 and caliper systems 136 at different axial positions may be circumferentially aligned or offset relative to each other.

FIG. 2 shows a cross-sectional side view of the downhole tool 100 of FIG. 1, and FIG. 3 shows a partial perspective view of the downhole tool 100 of FIG. 1, with the body 110 removed to more clearly illustrate the caliper system 136, according to one or more embodiments of the present disclosure. As shown in FIGS. 2 and 3, a mandrel 156 may be disposed within the body 110. The mandrel 156 may have an axial bore 112 that extends partially or completely therethrough. In the illustrated embodiment, a first or upper cap 108 may be disposed in an annular region between the mandrel 156 and the body 110. The upper cap 108 may also be an annular cap and, as seen in FIG. 2, for instance, the upper cap 108 may be positioned proximate or within the upper end portion 114 of the body 110. In the same or other embodiments, a second or lower cap 106 may be disposed in the annular region between the mandrel 146 and the body 110, may have an annular shape, and may be proximate or within the lower end portion 116 of the body 110.

In the illustrated embodiment, a piston 150 may be disposed within the body 110 and configured to move axially within the body 110. The piston 150 may include a head 152 having a shaft 154 coupled thereto and extending axially therefrom. The head 152 may abut the lower cap 106, and the shaft 154 may extend axially toward the caliper system 136 and/or the upper end portion 114. In some embodiments, the shaft 154 may be coupled to the mandrel 156 (e.g., a lower end of the mandrel). In the particular embodiment shown in FIG. 2, the shaft 154 is coupled around an exterior surface of the mandrel 156; however, in other embodiments, the mandrel 156 may be coupled to an exterior surface of the shaft 154, the shaft 154 and mandrel 156 may be coupled end-to-end, the shaft 154 and mandrel 156 may be coupled by one or more intermediate components, or the shaft 154 and the mandrel 156 may be disconnected.

In FIGS. 2 and 3, a spring 190 is shown as being disposed around the shaft 154 of the piston 150. The spring 190 may act as a biasing member to bias the piston 150 toward the lower end portion 116 of the body 110. The spring 190 may be a compression spring that compresses in an axial direction (e.g., toward the upper end portion 114 of the body 110) when exposed to an axial force. A stop ring 192 may be disposed around the shaft 154 of the piston 150. The stop ring 192 may restrict axial movement of the spring 190. For instance, the stop ring 192 may restrict, if not prevent, an upper axial end portion of the spring 190 from moving or sliding axially (e.g., toward the upper end portion 114 of the body 110) past the stop ring 192 when the spring 190 is compressed. In some embodiments, the spring 190 may be compressed between the stop ring 192 and the head 152. A maximum distance between the head 152 and stop ring 192 may allow the spring 190 to be fully expanded; however, in other embodiments the maximum distance between the head 152 and the stop ring 192 may maintain the spring 190 under some compression. In some embodiments, the stop ring 192 may be fixed relative to the body 110 while the head 152 and shaft 154 may be movable relative to the body 110. Accordingly, the distance between the stop ring 192 and the head 152 may change as the piston 150 is activated. In other embodiments, however, the stop ring 192 may be axially movable relative to the body 110, and the head 152 may be axially fixed relative to the body 110.

Each spring gear assembly 160 may be coupled to the body 110 and/or to the shaft 154 of the piston 150. For example, each spring gear assembly 160 may be coupled to the body 110 via a support bar 188 as shown in FIG. 3. The support bar 188 may be fixed at an axial position along the body 110, and the spring gear assembly 160 coupled to the support bar 188 may be maintained axially stationary with respect to the body 110. In some embodiments, the support bar 188 may rotate within the body 110 and/or the spring gear assembly 160 may include components that rotate or pivot around the support bar 188.

According to some embodiments, the shaft 154 of the piston 150 may be configured to move axially with respect to the spring gear assemblies 160 and the body 110. The spring gear assemblies 160 may each include a spring 162. The spring 162 may act as a biasing member to bias at least a portion of the spring gear assemblies 160. For instance, the spring 162 may be a torsion spring configured to rotate about the support bar 188 and/or to bias a portion of the spring gear assembly 160 towards rotation in a particular direction around the support bar 188.

Each spring gear assembly 160 may be coupled to a corresponding arm assembly 140. In some embodiments, the spring gear assemblies 160 are coupled to corresponding arm assemblies 140 via a pin slot connector 180. More particularly, a pin connector 170 of the pin slot connector 180 may be coupled to each spring gear assembly 160, and a slot connector 182 of the pin slot connector 180 may be coupled to each arm assembly 140. The pin connector 170 may include a pin 172 extending therefrom. The pin 172 may be positioned within a slot 184 formed in the corresponding slot connector 182. In some embodiments, the slot 184 may have an elongate shape. In such an embodiment, the pin 172 may be axially movable along the elongate length of the slot 184. Although not specifically shown, in another embodiment, the pin connectors 170 may be coupled to a corresponding arm assembly 140, and the slot connectors 182 may be coupled to a corresponding spring gear assembly 160.

The arm 142 of each arm assembly 140 may be coupled to a measurement device 124. In this embodiment, the measurement device 124 may be positioned around the mandrel 156, and in the annular region between the mandrel 156 and the body 110. The measurement device 124 may be configured to sense or measure movement of the arm 142. For example, the arm 142 may be pivotally connected to the measurement device 124. The measurement device 124 may sense or measure the rotational/pivoting movement of the arm 142 with a mechanical device, electronic device (e.g., an electromagnet and/or radio transmitter), a potential meter, a rotary encoder, or the like. As discussed in greater detail herein, in one embodiment, the measurement device 124 may include a magnet or other position indicator. Such a position indicator may move axially within the measurement device 124. In at least some embodiments, the distance that the position indicator moves axially may correspond to the rotational/pivoting movement of the arm 142 and/or the radial movement of the arm assembly 140.
The measurement device 124 may be in communication with a probe or other electronic device that is optionally disposed within the bore 112 of the mandrel 156. The electronic device 134 may include a magnetometer. For example, a magnetometer in the electronic device 134 may be configured to detect the position of the magnet in the measurement device 124, which position may correspond to the position of the arm 142. The electronic device 134 may also include a transmitter configured to transmit the measurement to another measurement-while-drilling (MWD) tool, a logging-while-drilling (LWD), a mud-pulse telemetry transmitter, etc. or to the surface. Such transmission may occur in real-time or near real-time. Real-time or near real-time transmission may allow monitoring/recording (e.g., at an upheave or surface location) of the diameter or other geometry of the wellbore 102 (FIG. 1) as measured by the downhole tool 100, during drilling or remedial operations within the wellbore 102. Remedial operations may include, for instance, cementing operations, milling operations, fishing operations, plugging operations, and the like.

FIG. 4 is a side view of the arm 142 of FIG. 3, and illustrates an example stop latch 148. The stop latch 148 may be configured to limit the rotational/pivoting movement of the arm 142 in one direction or in both directions. As shown, the illustrative stop latch 148 may be configured to limit the rotational/pivoting movement of the arm 142 in a clockwise direction when the arm 142, which direction may also be a radially-inward direction.

FIG. 5 is a cross-sectional perspective view of the arm 142, the roller 144, and the slot connector 182 shown in FIG. 3, according to one or more embodiments of the present disclosure. The roller 144 may be disposed around the arm 142. One or more bushings or bearings 146 may be disposed between the arm 142 and the roller 144. The bearings 146 may reduce the friction between the arm 142 and the roller 144 to allow the roller 144 to rotate around the arm 142. This may allow the roller 144 to “roll” along the wall of the wellbore when the downhole tool rotates about its longitudinal axis within the wellbore.

FIG. 6 is a perspective view of a portion of the piston 150 shown in FIG. 3 and FIG. 7 is a cross-sectional view of the spring gear assembly 160 coupled to the shaft 154 of the piston 150 of FIG. 3, according to one or more embodiments of the present disclosure. The shaft 154 of the piston 150 may include a plurality of cogs or teeth 166 formed on the outer surface thereof. The teeth 166 on the shaft 154 may be axially offset from one another along the shaft 154. In some embodiments, the teeth 166 may form an axial rack of teeth 166.

The spring gear assembly 160 may include a gear 168 that has a plurality of cogs or teeth 166 formed on the outer surface thereof. The teeth 164 on the gear 168 may be circumferentially offset from one another, with each configured to fit within or engage the teeth 166 on the shaft 154. In the illustrated embodiment, the teeth 164 may extend circumferentially around a portion of the gear 168. For instance, the teeth 164 may extend around between 90° and 270° of the gear 168; although, in other embodiments the teeth 164 may extend around less than 90° or greater than 270° of the gear 168. In more particular example embodiments, the teeth 164 may extend around between 130° and 150°, between 140° and 160°, between 150° and 170°, between 160° and 190°, between 170° and 190°, between 180° and 200°, or between 190° and 210°, between 200° and 220°, or between 210° and 230°. In some embodiments, the teeth 164 may extend around a full circumference of the gear 168.

The circumferentially offset of the teeth 164 may correspond to the axial distance between the teeth 166. Consequently, when the shaft 154 of the piston 150 moves axially with respect to the spring gear assembly 160 of the illustrated embodiment, the engagement of the teeth 164, 166 may cause the gear 168 to rotate and move axially along the rack of teeth 166. In such an arrangement, the gear 168 may operate as a pinion cooperating with the rack of teeth 166.

FIG. 8 is an exploded perspective view of the spring gear assembly 160 of FIGS. 3 and 7, according to one or more embodiments of the present disclosure. The spring gear assembly 160 may include a spring 162, a gear 168, a frame 178, and a support sleeve 186. In some embodiments, a lateral portion 161 of the spring 162 may be configured to fit within a corresponding slot 169 in the gear 168. In the same or other embodiments, one or more end portions 163 (two are shown in FIG. 8) of the spring 162 may be configured to fit within corresponding first slots 179 in the frame 178. The illustrated spring 162 is a torsional spring. By virtue of the lateral portion 161 remaining in the slot 169 and the end portions 163 remaining in the first slots 179 while the gear 168 rotates relative to the frame 178 (or vice versa), the bias of the spring 162 may be overcome and the spring 162 can be partially uncoiled.

The support sleeve 186 may be positioned inside the spring 162 and/or the frame 178. In at least some embodiments, the support sleeve 186 may be used to center or otherwise maintain a desired positioning of the spring 162 within the frame 178 while the spring 162 winds and unwinds. In some embodiments, the frame 178 may include a second slot 174 configured to have a tab 176 of the pin connector 170 positioned therein. In the illustrated embodiment, the tab 176 and the slot 174 may have elongated shape. Optionally, such a shape may be used to limit if not prevent relative rotation between the pin connector 170 and the frame 178. In the same or other embodiments, the tab 176 may be sized to be about the same size as the slot 174 to further restrict or even prevent relative axial movement between the pin connector 170 and the frame 178. In other embodiments, however, the slot 174 and/or tab 176 may have other shapes or configurations. For instance, the tab 176 may have a circular shape to allow rotation within the slot 174. The slot 174 may also be circular or have another shape or configuration.

FIG. 8 depicts an example embodiment in which the frame 178 is separable into two halves, and in which each have a corresponding slot 174 (one for each end portion 163 of the spring 162). The pin connector 170 is also shown as having two tabs 176, one on each lateral side thereof so as to couple to each half of the frame 178. Similarly, the support sleeve 186 is shown as having two individual portions. It should be appreciated in view of the disclosure herein that in other embodiments the frame 178 may be formed of a single, unitary component and/or the sleeve support 186 may be formed as a single, unitary component. In the same or other embodiments, the spring 162—which is shown as having two (2) coils connected by the lateral portion 161—have more than two (2) coils or may have a single coil.

FIG. 9 is a cross-sectional view of the downhole tool of FIG. 2 taken along the line 9-9, and particularly shows a spring gear assembly 160 according to one or more embodiments. Three (3) apertures 122 are shown formed into the body 110 and circumferentially-offset from one another. The
apertures 122 are shown as extending radially through the body 110, and between the mandrel 156 and the outer surface 118 of the body 110. Each aperture 122 may have a spring gear assembly 160 disposed at least partially therein. In the illustrated embodiment, each spring gear assembly 160 may be coupled to the body 110 with a support bar 188. The support bar 188 may allow the spring gear assembly 160 to rotate thereabout, while limiting, and potentially preventing, axial movement of the spring gear assembly 160 with respect to the body 110.

FIG. 10 is a cross-sectional side view of an example downhole tool 100 showing an illustrative measurement device 124. FIG. 11 is a partial perspective view of the measurement device 124 shown in FIG. 10, and FIG. 12 is a partial top view of the measurement device 124 shown in FIG. 11, according to one or more embodiments of the present disclosure. The measurement device 124 may include a gear shaft 126, one or more gears (one is shown 128), one or more pulleys (two are shown 130-1, 130-2), and a magnet 132. In at least some embodiments, the measurement body 124 may define or include a body, casing, or other housing for one or more of the gear shaft 126, gears 128, pulleys 130-1, 130-2, or magnet 132. According to at least some embodiments, the housing may be a pressure compensated casing or other housing. For instance, a pressure compensation piston 129 may be fully or partially disposed within the measurement device 124.

The arm 142 of the arm assembly 140 may be coupled to the gear shaft 126 such that the rotational movement of the arm 142 is transferred to the gear shaft 126. The gear shaft 126 may be coupled to the gear 128 such that the rotational movement of the gear shaft 126 may be transferred to the gear 128. Although a single gear 128 is shown in FIG. 11, it should be appreciated in view of the disclosure herein that two or more gears 128 may be used in moving the magnet 132 and/or that any desired gear ratio may be used. For instance, a gear ratio may be used to amplify the rotational movement of the gear shaft 126 and the arm 142. A desired gear or other transmission ratio may be achieved by increasing or decreasing the number of gears 128 and/or the size or number of teeth on each gear 128. As shown in FIG. 12, for instance, two gears 128-1, 128-2 may be coupled to the gear shaft 126. The width of the first gear 128-1 and corresponding pinion may be less than the width of the second gear 128-2 and corresponding pinion. In the illustrated embodiment, the diameter of the gear 128-1 may be larger than the diameter of the gear 128-2. Consequently, for each rotation of the gear 128-1, the gear 128-2 may rotate multiple times. The difference in width and/or the difference in gear diameter/size may account for a loading ratio effect.

The first and/or second gear 128-1, 128-2 may be coupled to a first pulley 130-1 by direct engagement or through indirect engagement of one or more other gears. In the illustrated embodiment, the rotational movement of the gear 128-2 may cause the first pulley 130-1 to rotate. More particularly, the gear shaft 126 may rotate. The gear 128-1 may be co-axial with the gear shaft 126 and may therefore rotate as the gear shaft 126 rotates. By virtue of engagement between the gear 128-2 and the gear 128-1, the gear 128-1 may also be caused to rotate. As shown in FIG. 12, the illustrated embodiment may include a pinion 131-1 coupled to, and optionally co-axial with, the first pulley 130-1. The pinion 131-1 may include teeth that engage with teeth of the gear 128-1. When the gear shaft 126 rotates, the first pulley 130-1 may therefore be rotated through the interconnection of the gears 128-1, 128-2 and the pinion 131-1.

When the first pulley 130-1 rotates, the rotation may cause a line or cable 123 disposed at least partially thereabout to move the magnet 132 in a linear or axial direction within the measurement device 124. The second pulley 130-2 may serve to reduce or prevent slack in the cable 123. In some embodiments, the cable 123 may be tensioned. For instance, the cable 123 may be tensioned by a preload torsion spring 125 or other biasing or tensioning member.

The movement of the magnet 132 may correspond to the rotational/pivoting movement of the arm 142 (see FIG. 10). In particular, the rotational/pivoting movement of the arm 142 may cause the gear shaft 126 to rotate, and such rotation may be translated into axial movement of the magnet 132. Optionally, the movement of the magnet may be proportionally related to the rotational/pivoting movement of the arm 142.

A probe or other electronic device 134 (see FIG. 2) may include one or more sensors that are configured to sense or measure the axial movement or position of the magnet 132. The magnet 132 may therefore be one example of a device that may be used to determine the position of the arm 142. In other embodiments, the magnet 132 may be replaced by other components (e.g., ferrous metals, electronic components, etc.) that may be used in determining the position of the arm 142. The electronic device 134 may transmit the measured or determined position of the magnet 132 to a MWD, pulse transmitter, or other downhole tool, or to the surface. In another embodiment, the electronic device 134 may operate in a memory mode in which the information is stored for use after a run by a drilling or remedial tool string. In some embodiments, the electronic device 134 may use the obtained measurements in real-time or near real-time to determine the rotational/pivoting movement of the arm 142. As discussed in greater detail herein, the rotational/pivoting movement of the arm 142 may be used to determine the diameter or other geometry of the wellbore.

FIG. 13 is a partial perspective view of another example of a measurement device 224 that may be used in downhole tools such as those disclosed herein (e.g., downhole tool 100 of FIGS. 1 and 2). Rather than, or in addition to, having a set of one or more gears and/or one or more pulleys, the measurement device 224 may have a piston 227 disposed therein. The piston 227 may be coupled to a gear shaft 226 via a connection bar 229. The gear shaft 226 may be coupled to an arm assembly or other component as discussed herein. The piston 227 may be disposed within a first chamber 233 in the measurement device 224, and a magnet 232 or other positioning device may be disposed within a second chamber 235 that is optionally in fluid communication with the first chamber 233. When the gear shaft 226 rotates, the gear shaft 226 may cause the connection bar 229 to rotate and/or translate, thereby causing the piston 227 to move within the first chamber 233. Movement of the piston toward the second chamber 235 may compress or move a fluid within the first chamber 233, which may cause the magnet 232 to move axially within the second chamber 235. The first chamber 233 may have a greater cross-sectional size (e.g., diameter) than the second chamber 235, which may amplify movement of the magnet 232 with respect to the piston 227. In other words, the magnet 232 may move a larger axial distance than the piston 227. In other embodiments, the relationship may be reversed or the magnet 232 and piston 227 may move about the same dis-
In still other embodiments, the magnet 232 may be positioned on or in the piston 227, or the piston 227 may be used as a measurement device.

**FIG. 14** is a cross-sectional view of a downhole tool 300 incorporating another embodiment of a measurement device 324, and **FIG. 15** is a partial perspective view of the measurement device 324 of FIG. 14. In this particular embodiment, the measurement device 324 may include a magnet 332 coupled to a shaft 336. In this same embodiment, a gear shaft 326 may be coupled to a gear amplifier 337 of the measurement device 324. The gear amplifier 337 may include teeth for engaging the gear shaft 326, and an extension arm extending from a gear or teeth portion. The extension arm may engage a shaft 336. As the gear shaft 326 rotates, the gear shaft 326 may therefore cause the gear amplifier 337 to rotate, and the gear amplifier 337 may cause the shaft 336 to move. In this particular embodiment, the shaft 336 may be moved in a linear direction; however, other embodiments are contemplated in which a shaft is rotated and/or moved in a curved fashion. The shaft 336 may have the magnet 332 or other positioning device coupled thereto. Optionally, one or more support bearings 338 may be configured to guide the linear or other movement of the shaft 336. In at least one embodiment, the support bearings 338 may be stationary with respect to the shaft 336, and the shaft 336 may slide or otherwise move.

**FIG. 16** is a cross-sectional view of the downhole tool 300 shown in FIG. 14, according to one or more embodiments of the present disclosure. As shown, the downhole tool 300 may include three measurement devices 324 that are circumferentially offset from one another. Thus, three magnets 332-1, 332-2, and 332-3 may be circumferentially offset from one another within the body 310. As will be appreciated by one having ordinary skill in the art in view of the disclosure herein, the magnets 332-1, 332-2, 332-3 may be movable independently of each other based on the relative position of a corresponding arm or other device for measuring wellbore geometry.

In some embodiments, a mandrel 356 may be shaped and sized to form one or more flow channels (three are shown 339-1, 339-2, 339-3) between the mandrel 356 and an electronic device 334 (see FIG. 14). The flow channels 339-1, 339-2, 339-3 may be circumferentially offset from one another. Optionally, the flow channels 339-1, 339-2, 339-3 are circumferentially offset by an amount corresponding to a circumferential offset of the magnets 332-1, 332-2, 332-3. In some embodiments, each flow channel 339-1, 339-2, 339-3 may be positioned between two circumferentially adjacent magnets 332-1, 332-2, 332-3. The total cross-sectional area of the flow channels 339-1, 339-2, 339-3 may vary, and in some embodiments may range from 3 cm² and 100 cm². For instance, the cross-sectional area may be between 5 cm² and 10 cm², between 10 cm² and 20 cm², between 20 cm² and 40 cm², or between 40 cm² and 60 cm². In other embodiments, the cross-sectional area may be less than 5 cm² or greater than 100 cm².

**FIG. 14** is a cross-sectional view of the downhole tool 300 in an active or expanded state with the arm assembly 540 expanded radially outward from its inactive or retracted state. In other embodiments, more or fewer than three (3) sensors may be used. According to some aspects of the present disclosure, each sensor 341-1, 341-2, 341-3 may be aligned or otherwise associated with a corresponding magnet 332-1, 332-2, 332-3. **FIG. 17** shows a schematic view of three magnets 432-1, 432-2, 432-3, each disposed within or otherwise aligned with a different measurement device, according to one or more embodiments of the present disclosure. In at least one embodiment, two or more sensors (three are shown 441-1, 441-2, 441-3) may be coupled to the body of a downhole tool. For instance, the sensors 441-1, 441-2, 441-3 may be disposed within a tube and/or circumferentially offset from one another (see, e.g., sensors 341-1, 341-2, 341-3 of FIG. 16). For example, the three (3) sensors 441-1, 441-2, 441-3 may be disposed about 120° apart around the circumference of the body of a downhole tool. In other embodiments, the circumferential offset between circumferentially adjacent sensors may be less than or greater than 120°. For instance, if more than three (3) sensors are used, there may be a reduced circumferential offset. If two (2) sensors are used, there may be a larger circumferential offset. In other embodiments, there may be different circumferential offsets between adjacent sensors.

**FIG. 18-1** is a partial cross-sectional view of a downhole tool 500 in an inactive or retracted state, in accordance with some embodiments of the present disclosure. The downhole tool 500 of FIG. 18-1 may operate in a manner similar to the downhole tool 100 of FIGS. 1 and 2 and the downhole tool 300 of FIG. 16. The active state of the downhole tool 500 may be equally applicable to the downhole tool 100 and/or downhole tool 300, and vice versa.

**FIG. 18-2** is a cross-sectional view of the downhole tool 500 in an active state with the arm assembly 540 folded or otherwise retracted into the body 510 of the downhole tool 500. When the downhole tool 500 is in the active state, a piston 550 may be positioned proximate a lower end portion 516 of the body 510. The spring 590 may also be generally uncompresssed in such an embodiment. In addition, the arm 542 and the roller 544 (or other device for engaging a wall of a wellbore) may be folded or otherwise retracted into an aperture 522 of the body 510, and the outer surface of the arm 542 and/or the roller 544 may be aligned with, or positioned radially-inward from, the outer surface 518 of the body 510.
ally-outward for engaging or otherwise contacting the wall of a wellbore, according to one or more embodiments of the present disclosure. When the downhole tool 500 is actuated into the active state, the piston 550 may slide or otherwise move toward the upper end portion 514 of the body 510, thereby compressing the spring 590. As the piston 550 moves, the engagement of the teeth on the shaft 554 of the piston 550 with teeth on the gear 568 of the spring gear assembly 560 may cause the gear 568 to rotate. The rotation of the gear 568 may exert a force on the arm assembly 540 (e.g., through the pin slot connector 580) in a direction that is radially-outward relative to the body 510. When the arm assembly 540 is unobstructed, as shown in FIG. 18-3, the force exerted by the spring gear assembly 560 may cause the arm assembly 540 to pivot or rotate radially-outward from the body 510. For example, the arm assembly 540 may pivot or rotate radially-outward until the roller 544 or other engagement device contacts the wall of the wellbore.

When the arm assembly 540 is obstructed, as shown in FIG. 18-2, the force exerted by the spring gear assembly 560 may be less than an opposing force exerted on the roller 544 in a direction that is radially-inward relative to the body 510. For example, when a side of the body 510 abuts the wall of the wellbore, the wall of the wellbore may limit or even prevent the arm assembly 540 from rotating into the direction of the wall. The pin slot connector 580 may enable the arm assembly 540 to remain folded into the apertures 522 of the body 510 when the downhole tool 500 is in the inactive state. More particularly, the pin 572 may be configured to slide or otherwise move within a slot (see slot 184 of FIG. 3) to allow the arm assembly 540 to remain folded into the apertures 522 of the body 510 when the force exerted by the spring gear assembly 560 is less than the opposing force exerted by the wall of the wellbore.

FIG. 19-1 is a cross-sectional view of the downhole tool 500 of FIG. 18-1 in the inactive state with the arm assemblies 540 retracted into the body of the downhole tool 500, according to one or more embodiments of the present disclosure. As discussed herein, when the downhole tool 500 is in an inactive state, the arms 542 and the rollers 544 may be folded or otherwise retracted into the apertures 522 of the body 510, such that the outer surfaces of the arms 542 and/or the rollers 544 may be radially aligned with, or positioned radially-inward from, the outer surface 518 of the body 510.

FIG. 19-2 is a cross-sectional view of the downhole tool 500 in the active state with the arm assemblies 540-1, 540-2, 540-3 expanded radially-outward and into contact with the wall 504 of the wellbore 502, according to one or more embodiments of the present disclosure. When the downhole tool 500 is in the active state, the arms 542 and the rollers 544 may expand radially-outward from the body 510 to cause the rollers 544 to contact the wall 504 of the wellbore 502. As shown in FIG. 19-2, the longitudinal axis of the downhole tool 500 may be misaligned relative to the longitudinal axis of the wellbore 502. As such, two of the arm assemblies 540-1, 540-2 may be expanded radially-outward from the body 510, while the third arm assembly 540-3 may be restricted or even prevented from expanding radially-outward because the wall 504 of the wellbore 502 is contacting the outer surface 518 of the body 510 proximate the third arm assembly 540-3. In accordance with at least some embodiments, the weight of the downhole tool 500 and/or the fluid within the wellbore 502 may limit the ability of the third arm assembly 540-3 to push against the wall 504 of the wellbore 504 to align the longitudi-
embodiments of the present disclosure. Relative to the embodiment shown in FIG. 22, the measurement device 624 is shown as being moved axially along the body 610 toward the upper cap 608. In particular, once in the aperture 622, the measurement device 624 may be moved axially toward the upper end portion 614 of the body 610 until a shoulder 625 extending radially-outward from the measurement device 624 contacts or abuts the radial surface 611 of the body 610. In some embodiments, moving the measurement device 624 may also include moving the measurement device 624 radially. Optionally, the pin slot connector 680 may then be coupled to the spring gear assembly 660; however, as may be appreciated, this coupling may occur before or after the measurement device 624 is disposed within the aperture 622. Similarly, the arm assembly 640 may be coupled to the measurement device 624 before or after insertion of the measurement device into the aperture 622.

Fig. 24 shows a partial cross-sectional view of the downhole tool 600 with the measurement device 624 coupled to the body 610 and within the aperture 622 between the body 610 and the mandrel 656, according to one or more embodiments of the present disclosure. The upper cap 608 may have a plurality of threads formed on an inner surface thereof, and the mandrel 656 may have a plurality of threads formed on the outer surface thereof, which threads may be configured to engage the inner threads of the upper cap 608. The inner cap 608 may be rotated with respect to the body 610 and the mandrel 656, thereby causing the mandrel 656 to move axially within the body 610 toward the upper end portion 614 of the body 610. The mandrel 656 may move toward the upper end portion 614 of the body 610 until the outer shoulder 657 of the mandrel 656 contacts or abuts the measurement device 624 (which may abut the radial surface 611). Thus, the measurement device 624 may be coupled to the body 610 and secured in place between the body 610 and the mandrel 656.

The outer shoulder 657 of the mandrel 656 and/or the radial surface 611 of the body 610 may be straight, tapered, curved, or otherwise contoured. When the outer shoulder 657 is straight, it may be substantially perpendicular to a longitudinal axis extending through the mandrel 656 and/or the body 610. The straight outer shoulder 657 may not affect the centralization of the mandrel 656 because may not push the measuring devices 624 radially outward. Thus, there may not be a reaction force applied radially on the mandrel 656 to shift the mandrel 656 from its central location. When the outer shoulder 657 is tapered, the taper may be oriented at an angle between 2° and 130°. For instance, the angle may range from a low of 5°, 10°, 20°, or 30° to a high of 45°, 60°, 75°, or more with respect to the longitudinal axis extending through the mandrel 656 and/or body 610 (where 90° is perpendicular to the longitudinal axis). When the outer shoulder 657 is tapered, the outer shoulder 657 may apply a force to the measuring device 624 in the axial and radial directions, and this may tend to push the mandrel 656 off-center.

Fig. 25 shows a cross-section of a perspective view of the downhole tool 600 shown in Fig. 24, according to one or more embodiments of the present disclosure. In at least one embodiment, one or more grooves or slots (three grooves 659 are shown in Fig. 25) may be formed in the outer surface of the mandrel 656. The measuring devices 624 may each include a radial protrusion 627 or tab configured to fit within a corresponding slot 659 in the mandrel 656. The engagement of the radial protrusion 627 within the slot 659 may restrict or even prevent relative rotation of the mandrel 656 relative to the measuring devices 624. In some embodiments, engagement of the radial protrusion 627 with the slot 659 may restrict or even prevent rotation of the mandrel 656 and measuring devices 624 about the longitudinal axis extending through the mandrel 656 when the upper cap 608 (see FIG. 24) rotates. Thus, the mandrel 656 and the measuring devices 624 may move axially in response to the rotation of the upper cap 608, but may not rotate along with the upper cap 608. Although a slot 659 and a corresponding radial protrusion 627 are shown, it will appreciated in view of the disclosure herein that any engagement (e.g., an edge, a pin, etc.) may be used to restrict rotation of the mandrel 656 and/or the measuring devices 624. As will also be appreciated in view of the present disclosure, the illustrated mechanism for coupling the measuring device 624 to the mandrel 656 and/or the body 610 of the downhole tool 600 is not limited to measuring devices 624. For example, the same or a similar design may be used to couple any component to a downhole tool, or to insert any component at least partially within another tool, such as a downhole tool.

Once the downhole tool 600 is assembled, the downhole tool 600 may be run into a wellbore (e.g., wellbore 102 of FIG. 1) on a drill string or other drilling tubular. The downhole tool 600 may be in the inactive state as it is run into the wellbore. More particularly, the arm assemblies 640 may be folded or otherwise retracted through the apertures 622 and into the body 610, such that the outer surface of each arm 642 and/or the roller 644 may be aligned with, or positioned radially-inward from, the outer surface 618 of the body 610. The downhole tool 600 may then be actuated into the active state when the downhole tool 600 reaches the desired position/depth within the wellbore (e.g., a downhole position/location at which it is desired to measure the diameter or other geometry of the wellbore). In one or more embodiments, the downhole tool 600 may be actuated into or already in the active state while drilling (e.g., a drill bit coupled to the downhole tool 600 may be rotating to further drill the wellbore) or conducting other drilling operations. In one or more other embodiments, the downhole tool 600 may be actuated into or already in the active state while performing remedial operations within a wellbore (e.g., a mill may be coupled to the downhole tool and rotating to mill casing above or below the downhole tool 600, an underreamer may be increasing the diameter of the wellbore, a cementing apparatus may be cementing a rock-to-rock section of the wellbore, a stuck tool may be fished out of the wellbore, etc.). The diameter of a drilled wellbore may therefore be determined as the wellbore is drilled, as drilling operations are conducted, or as remedial operations are conducted. In drilling or remedial operations using drilling fluid or other hydraulic fluid, fluid may flow through the drill string and to the drilling or remedial tool. Where such tool is below the tool 600, the fluid may flow through the mandrel 656 of the downhole tool 600 in some embodiments.

To actuate the downhole tool 600 into the active state, the hydrostatic pressure of the fluid in a bore (e.g., bore 112 of FIG. 2) within the mandrel 656 of the downhole tool 600 may be increased. For example, a pump disposed at the surface may increase the flow rate through a drilling tubular and to the bore in the downhole tool 600, which may thereby increase the pressure in the bore. A portion of the fluid may flow from the bore, through a nozzle, bore, port, or other opening (e.g., opening 196 of FIG. 2) formed radially through the body 610, and to an annulus formed between the outer
surface of the body 610 and the wall of the wellbore. The difference pressure in the annulus between the downhole tool 600 and the wellbore and the pressure within the bore may result in activation of the downhole tool 600. More particularly, as the pressure of the fluid in the bore increases relative to the pressure in the annulus, the fluid may exert an axial force on a piston (e.g., piston 150 of FIG. 2). For instance, fluid pressure may build between a lower cap and a head of the piston. The lower cap may be relatively fixed at an axial position, and the building pressure may push against the head in a direction toward the upper end portion 614 of the downhole tool 600. The force exerted by the increased pressure of the fluid may become greater than the opposing force exerted by a spring or other biasing element. When this occurs, the piston may slide or otherwise move axially toward the upper end portion 614 of the downhole tool 600.

[0088] As the piston moves toward the upper end portion 614 of the downhole tool 600, a shaft (e.g., shaft 154 of FIG. 2) of the piston may also move, and engagement between the teeth (e.g., teeth 166 of FIG. 7) on the shaft of the piston and the teeth (e.g., teeth 164 of FIG. 7) on the gears of a gear assembly (e.g., spring gear assembly 160 of FIG. 2) may cause the gears to rotate (e.g., clockwise). The rotational movement of each gear may be transferred through the pin slot connector 680 to the arm assembly 640, which may cause the arm assembly 640 to pivot or rotate radially-outward from the body 610, and therefore into an active state.

[0089] More particularly, and as described in more detail with respect to the spring gear assembly 160 of FIG. 8, a gear 168 may be coupled to a spring 162, and rotational movement of the arm 168 may cause the spring 162 to rotate. The spring 162 may be coupled to a frame 178, and the rotational movement of the spring 162 may cause the frame 178 to rotate. The frame 178 may be coupled to the pin connector 170, and the rotational movement of the frame 178 may cause the pin connector 170 to rotate. The pin connector 170 may in turn be coupled to the arm 142 of the arm assembly 140 via the slot connector 182 (or to the arm assembly 640 of FIGS. 20, 21, 22, 23, 24, and 25), and the rotational movement of the pin connector 170 may cause the arm assembly 140 to pivot or rotate radially-outward.

[0090] With continued reference to the illustrative embodiment shown in FIGS. 20, 21, 22, 23, 24, and 25, the arm assemblies 640 may pivot or rotate radially-outward until rollers or other wellbore engagement elements contact the wall of the wellbore. As discussed herein, the movement of the arm assemblies 640 may be measured and translated into a measurement of the diameter or other geometry of the wellbore wall. When the arm assemblies 640 are rotated and the rollers or other wellbore engagement elements are in contact with the wellbore wall, a biasing member (e.g., spring 162 of FIG. 8) may be loaded and may hold the wellbore engagement elements against the formation while also allowing the arm assemblies 640 to move with changes in diameter of the wellbore.

[0091] The downhole tool 600 may rotate about a longitudinal axis extending therethrough, and the wellbore engagement elements may be configured to roll or slide along the wall of the wellbore. In at least one embodiment, one or more of the wellbore engagement elements may not expand radially-outward (or may expand radially-outward a lesser amount relative to other wellbore engagement elements) because the wall of the wellbore may be contacting or near the outer surface of the body 610 proximate the corresponding arm assembly 640 (see FIGS. 19-2 and 19-3). In some embodiments, as the downhole tool 600 rotates the arm assemblies 640 may cyclically expand and retract.

[0092] Each measurement device 624 may sense or measure the angle that the corresponding arm assembly 640 rotates through as it transitions from the inactive, retracted state to the active, expanded state. More particularly, the measurement device 624 may sense or measure the angle that the arm assembly 640 rotates through as it rotates radially-outward until the wellbore engagement element contacts with the wall of the wellbore. The angle through which the arm assembly 640 rotates may range from 0° to 720° in some embodiments. In some embodiments, for instance, the angle may be less than a full revolution. For instance, the angle may range from a low of 0°, 1°, 2°, 4°, 6°, or 8° to a high of 10°, 15°, 20°, 30°, 40°, or more. For example, the angle may be between 1° and 20°, between 2° and 15°, or between 2° and 10°.

[0093] Each measurement device 624 may convert the rotational movement of the corresponding arm assembly 640 into linear or axial movement of a magnet or other positioning element (see FIGS. 10-17), and an electronic device, probe, or the like may sense the axial distance that the positioning element moves. In at least one embodiment, a probe or electric device may transmit the sensed distance to a MWD, LWD, or other downhole tool, or to the surface. In another embodiment, the probe or other electric device may use the sensed distance to determine the diameter or other geometry of the wellbore to transmit the diameter of the wellbore to a MWD, LWD, other downhole tool, or to the surface. In still other embodiments, the probe or other electronic device may store the information.

[0094] After the measurements are taken and/or the diameter or other geometry of the wellbore is determined, the downhole tool 600 may be actuated back into the inactive state. To actuate the downhole tool 600 into the inactive state, hydrostatic pressure of the fluid in the bore of the downhole tool 600 may be decreased (e.g., to return the pressure near the pressure within the annulus). For example, a surface fluid pump may be turned off. The pressure may decrease until the force exerted by the fluid on the piston toward the first end portion 614 of the body 610 is less than the opposing force exerted by a spring or other biasing member toward a second end portion of the body 610. When the force exerted by the spring or other biasing member becomes greater than the force exerted by the fluid, the piston may move axially toward the lower end portion of the body 610.

[0095] As the piston moves toward the lower end portion of the downhole tool 600, the engagement between the teeth (see teeth 166 of FIG. 7) on the shaft of the piston and the teeth (see teeth 164 of FIG. 7) on the gears of a spring gear assembly 660 may cause the gears (e.g., gears 168 of FIG. 7) to rotate (e.g., counterclockwise). The rotational movement of each gear may be transferred through the pin slot connector 680 to the corresponding arm assembly 640, which may cause the arm assembly 640 to pivot or rotate radially-inward into the aperture 622 of the body 610 (i.e., into the inactive state).

[0096] In a more particular example shown in FIG. 8, a gear 168 may be coupled to a spring 162, and the rotational movement of the gear 168 may cause the spring 162 to partially unwind. The spring 162 may be coupled to the frame 178, and the rotational movement of the spring 162 may cause the frame 178 to rotate. The frame 178 may in turn be coupled to the pin connector 170, and the rotational movement of the
frame 178 may cause the pin connector 170 to rotate. The pin connector 170, which may be coupled to the arm 142 of the arm assembly 140 (e.g., via the slot connector 182), may rotate and cause the arm assembly 140 to pivot or rotate radially-inward.

[0097] Embodiments of the present disclosure may therefore relate to a system for measuring a diameter or other geometry of a wellbore. In accordance with some embodiments of the present disclosure, wellbore diameter may be obtained by using rollers or other wellbore engagement elements pushed against a wellbore wall through use of a spring or other biasing member. Arms connected to the wellbore engagement elements may rotate as the wellbore engagement elements are pushed radially-outward, and the wellbore diameter, wellbore eccentricity, or other wellbore geometry may be calculated from the rotational position of the arms. A measurement device may sense the rotation (e.g., by converting the rotational movement to an axial movement of a magnet or other device), and may communicate the information with one or more sensors within an electronic or other sensing tube or device. The sensing device save the data, or may communicate with a MWD, LWD, or other downhole tool to save data for later use, to send delayed or real-time data to other devices, or to send delayed or real-time data to the surface. The data that is saved or sent may be raw measurement data or may be the calculated wellbore diameter or other geometry. Moreover, such a downhole tool may be utilized with other downhole drilling or remedial tools, and while such drilling or remedial tools are actively operating within the wellbore. In still other embodiments, components of some embodiments of the present disclosure (e.g., spring gear assemblies, measurement devices, pin slot connectors, mandrel couplings, etc.) may be used in other devices or systems other than in connection with a device for measuring wellbore geometry.

[0098] A method is disclosed for coupling components together and may include inserting a component into an aperture formed between a body and a mandrel within the body. The component may be moved axially in one direction within the aperture until a shoulder extends radially outward from the component contacts a radial surface of the body. The mandrel may also be moved axially in the first direction until a shoulder extending radially outward from the mandrel contacts the component.

[0099] According to some embodiments, the component coupled to the mandrel includes a device configured to measure wellbore geometry.

[0100] According to some embodiments, moving the mandrel axially in the first direction includes rotating a cap within the body.

[0101] According to some embodiments, the cap and mandrel are configured to be threadably engaged together.

[0102] According to some embodiments, inserting the component into the aperture includes engaging a protrusion of the component with an axial slot formed in an outer surface of the mandrel.

[0103] According to some embodiments, the shoulder extending radially-outward from the mandrel is substantially perpendicular with respect to a longitudinal axis extending through the mandrel. In other embodiments, the shoulder extending radially-outward from the mandrel is tapered at an angle from 5° to 75° with respect to a longitudinal axis.

[0104] Additional embodiments relate to a device for measuring wellbore geometry and include an arm that can rotate about an axis extending through a pivot of the arm. A gear shaft may be coupled to the pivot of the arm and can rotate in response to rotation of the arm about the axis. A position indicator may be coupled to the gear shaft in a way allowing the position indicator to move axially in response to rotation of the gear shaft.

[0105] According to some embodiments, the device for measuring wellbore geometry may further include a housing in which the gear shaft and position indicator are located.

[0106] According to some embodiments, the device for measuring wellbore geometry may include a piston coupled to the gear shaft within the housing. The piston may be movable in an axial direction in response to rotation of the gear shaft.

[0107] According to some embodiments, the device for measuring wellbore geometry may use a magnet as the position indicator, and the magnet may move in response to axial movement of the piston.

[0108] According to some embodiments, the piston may be disposed with a fluid in the housing, and the piston may cause fluid to move or be compressed so as to exert a force on the magnet, thereby causing the magnet to move in the axial direction within the housing.

[0109] According to some embodiments, a gear may be coupled to the gear shaft and configured to rotate in response to rotation of the gear shaft.

[0110] According to some embodiments, a pulley may be coupled to the gear and the position indicator. The pulley may be configured to rotate in response to rotation of the gear.

[0111] According to some embodiments, a cable may be coupled to the pulley and the position indicator, and the cable may be configured to move the position indicator axially in response to rotation of the pulley.

[0112] Devices for measuring wellbore geometry may also include a downhole tool for measuring wellbore geometry while performing drilling or remedial operations. A body may define a bore passing through a full or partial portion of the body, and a mandrel may be positioned in the bore. A measurement device may be located between the body and the mandrel, and may include a housing, a gear shaft in the housing, and a position indicator within the housing and which moves linearly in response to rotation of the gear shaft. An arm may also be coupled to an end portion of the gear shaft to rotate about an axis and cause the gear shaft to rotate.

[0113] According to some embodiments, an arm may be configured to rotate radially outward from the body and into contact with a wall of a wellbore, and linear movement of the position indicator may be proportional or otherwise related to extent of the radially outward movement of the arm and/or to the wellbore geometry.

[0114] According to some embodiments, a gear is coupled to the gear shaft and rotates in response to rotation of the gear shaft, while a pulley is coupled to the gear and rotates in response to rotation of the gear.

[0115] According to some embodiments, a cable is coupled to the pulley and position indicator and moves the position indicator linearly as the pulley rotates.

[0116] According to some embodiments, there may be multiple measurement devices and the downhole tool may include two measurement devices circumferentially offset from each other about the mandrel. A position indicator of one measurement device may be in a first zone while a position indicator of a second measurement device may be in a second zone that is axially offset from the first zone.
In the description herein, various relational terms are provided to facilitate an understanding of various aspects of some embodiments of the present disclosure. Relational terms such as “bottom,” “below,” “top,” “above,” “back,” “front,” “left,” “right,” “rear,” “forward,” “up,” “down,” “horizontal,” “vertical,” “clockwise,” “counterclockwise,” “upper,” “lower,” and the like, may be used to describe various components, including their operation and/or illustrated position relative to one or more other components. Relational terms do not indicate a particular orientation for each embodiment within the scope of the description or claims. For example, a component of a BHA that is “below” another component may be more downhole while within a vertical wellbore, but may have a different orientation during assembly, when removed from the wellbore, or in a deviated borehole. Accordingly, relational descriptions are intended solely for convenience in facilitating reference to various components, but such relational aspects may be reversed, flipped, rotated, moved in space, placed in a diagonal orientation or position, placed horizontally or vertically, or similarly modified. Relational terms may also be used to differentiate between similar components; however, descriptions may also refer to certain components or elements using designations such as “first,” “second,” “third,” and the like. Such language is also provided merely for differentiation purposes, and is not intended limit a component to a singular designation. As such, a component referenced in the specification as the “first” component may for some but not all embodiments be the same component that referenced in the claims as a “first” component.

Furthermore, to the extent the description or claims refer to “an additional” or “other” element, feature, aspect, component, or the like, it does not preclude there being a single element, or more than one, of the additional element. Where the claims or description refer to “a” or “an” element, such reference is not be construed that there is just one of that element, but is instead be inclusive of other components and understood as “one or more” of the element. It is to be understood that where the specification states that a component, feature, structure, function, or characteristic “may,” “might,” “can,” or “could” be included, that particular component, feature, structure, or characteristic is provided in some embodiments, but is optional for other embodiments of the present disclosure. The terms “couple,” “coupled,” “connect,” “connection,” “connected,” “in connection with,” and “connecting” refer to “in direct connection with,” “integral with,” or “in connection with via one or more intermediate elements or members.”

Although various example embodiments have been described in detail herein, those skilled in the art will readily appreciate in view of the present disclosure that many modifications are possible in the example embodiments without materially departing from the present disclosure. Accordingly, any such modifications are intended to be included in the scope of this disclosure. Likewise, while the disclosure herein contains many specifics, these specifics should not be construed as limiting the scope of the disclosure or of any of the appended claims, but merely as providing information pertinent to one or more specific embodiments that may fall within the scope of the disclosure and the appended claims. Any described features from the various embodiments disclosed may be employed in combination. In addition, other embodiments may also be devised which lie within the scopes of the disclosure and the appended claims. Each addition, deletion, and modification to the embodiments that falls within the meaning and scope of the claims is to be embraced by the claims.

While embodiments disclosed herein may be used in an oil, gas, or other hydrocarbon exploration or production environment, this environment merely illustrates one environment in which embodiments of the present disclosure may be used. Systems, tools, assemblies, methods, and other components discussed herein, or which would be appreciated in view of the disclosure herein, may be used in other applications and environments, including in automotive, aquatic, aerospace, hydroelectric, or even other downhole environments. The terms “wellbore,” “borehole,” and the like are therefore also not intended to limit embodiments of the present disclosure to a particular industry or environment. A wellbore or borehole may, for instance, be used for oil and gas production and exploration, water production and exploration, mining, utility line placement, or myriad other applications.

Certain embodiments and features may have been described using a set of numerical upper limits and a set of numerical lower limits. It should be appreciated that ranges including the combination of any two values, e.g., the combination of any lower value with any upper value, the combination of any two lower values, and/or the combination of any two upper values are contemplated unless otherwise indicated. Certain lower limits, upper limits and ranges may appear in the description and/or one or more claims. Any numerical value is “about” or “approximately” the indicated value, and takes into account experimental error and variations that would be expected by a person having ordinary skill in the art.

What is claimed is:

1. A downhole tool for measuring wellbore geometry, comprising:
   - a body having a bore extending at least partially therethrough, the body also having an aperture formed radially therein;
   - an arm having a first end portion movably coupled to the body, the arm being pivotable between a retracted position in which the arm is within the aperture and an expanded position in which the arm is at least partially radially-outward relative to the body;
   - a measurement device coupled to the body and configured to measure a pivoting motion of the arm; and
   - a piston disposed in the bore of the body and movably coupled to a second end portion of the arm, the piston responsive to hydraulic pressure to cause the arm to pivot between the retracted position and the expanded position.

2. The downhole tool of claim 1, the arm being configured to pivot through an angle between 1° and 20°.

3. The downhole tool of claim 1, the arm being configured to contact a wall of a wellbore when in the expanded position.

4. The downhole tool of claim 3, further comprising:
   - a roller coupled to the arm, the roller being configured to contact the wall of the wellbore when the arm is in the expanded position.

5. The downhole tool of claim 1, the measurement device including a magnet configured to move axially within the measurement device.

6. The downhole tool of claim 5, further comprising:
   - an electronic device coupled to the body, the electronic device including a magnetometer.
7. The downhole tool of claim 6, the magnetometer being configured to measure a distance that the magnet moves.

8. The downhole tool of claim 5, the magnet being configured to move axially a distance proportional to a pivoting rotation of the arm.

9. The downhole tool of claim 8, the measurement device being configured to use the pivoting rotation of the arm to determine the diameter of a wellbore.

10. The downhole tool of claim 1, the arm being biased toward the configured to be positioned radially-inward from an outer surface of the body when in the retracted position in the aperture and at least partially radially-outward relative to the outer surface of the body when in the expanded position.

11. A tool for measuring geometry, comprising:
   a body having an axial bore extending at least partially therethrough;
   a piston coupled to the body and configured to move axially within the body from a first position to a second position when hydraulic pressure of a fluid in the bore is increased;
   a spring gear assembly coupled to the piston and configured to rotate when the piston moves between the first position and the second position;
   an arm coupled to the body and the spring gear assembly and configured to move radially relative to the body when the spring gear assembly rotates; and
   a measuring device coupled to the arm and configured to measure the movement of the arm.

12. The tool of claim 11, the piston including a shaft having plurality of teeth coupled thereto and axially spaced along the shaft, the spring gear assembly including a gear having a plurality of teeth coupled thereto and circumferentially spaced around at least a portion of the gear, the plurality of teeth of the gear being configured to engage the plurality of teeth of the shaft.

13. The tool of claim 12, the piston being configured to use engagement of the plurality of teeth of the shaft with the plurality of teeth of the gear to convert the axial movement of the piston to rotational movement of the gear when the piston moves between the first position and the second position.

14. The tool of claim 13, further comprising:
   a connector coupled to and disposed between the arm and the spring gear assembly, the connector configured to pivot the arm radially when the piston moves between the first position and the second position.

15. The tool of claim 11, the measuring device being configured to use the measured movement of the arm to determine a diameter of a wellbore.

16. A method for measuring a diameter of a wellbore while performing a downhole drilling or remedial operation, comprising:
   increasing a pressure of a fluid in a bore that extends through a body of a downhole tool within a wellbore;
   moving a piston axially within the body from a first position to a second position in response to the increased pressure in the bore;
   pivoting an arm movably coupled to the body radially-outward in response to the piston moving from the first position to the second position;
   sensing the pivoting of the arm with a measuring device coupled to the arm while drilling or performing a remedial operation; and
   determining a diameter of the wellbore based upon the pivoting of the arm.

17. The method of claim 16, wherein pivoting the arm comprises:
   rotating a gear to the body in response to the piston moving from the first position to the second position; and
   pivoting the arm radially-outward in response to the rotation of the gear.

18. The method of claim 16, wherein determining the diameter of the wellbore comprises:
   moving a magnet axially a distance proportional to an amount by which the arm pivots; and
   determining the diameter of the wellbore based upon the axial distance the magnet moves.

19. The method of claim 16, further comprising:
   contacting a wall of the wellbore with a roller coupled to the arm when the arm is positioned radially-outward from the body.

20. The method of claim 19, further comprising:
   rotating the downhole tool while the arm is positioned radially-outward from the body such that the roller rolls along the wall of the wellbore.

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