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Mueller et al.

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(54) **DOWNHOLE DIRECTIONAL DRILLING TOOL**

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(60) Provisional application No. 62/805,977, filed on Feb. 15, 2019.

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E21B 7/06 (2006.01)

(52) **U.S. Cl.**
CPC ***E21B 7/062*** (2013.01)

(58) **Field of Classification Search**
None
See application file for complete search history.

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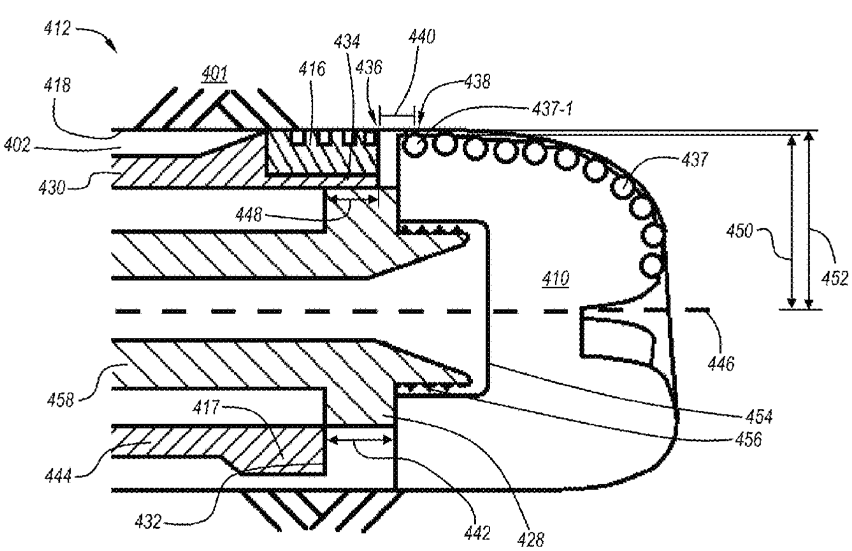
(57) **ABSTRACT**

A downhole tool has a directional pad that contacts a wellbore wall at a pad contact location and a drill bit with at least one active cutting element that contacts the wellbore wall at a cutting element contact location. A contact distance between the pad contact location and the cutting element contact location being 3 in. (7.6 cm) or less.

16 Claims, 8 Drawing Sheets



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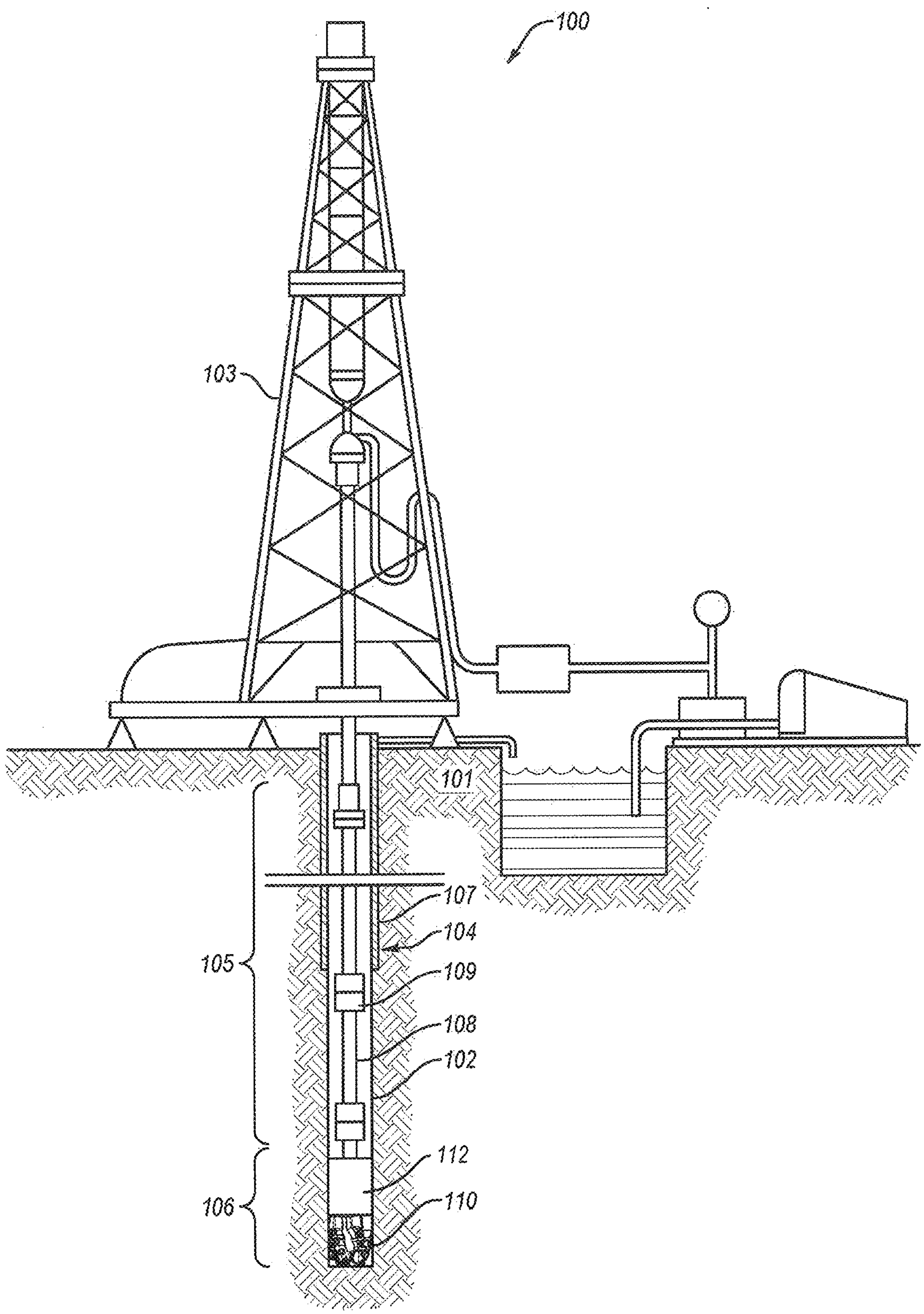

FIG. 1

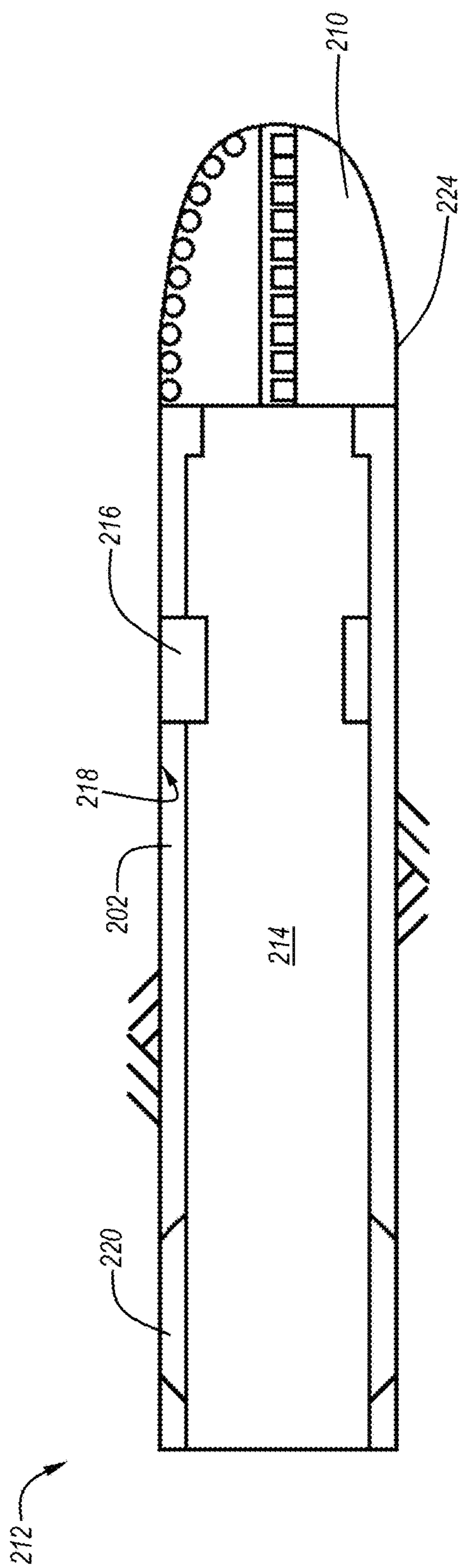

FIG. 2
(Prior Art)

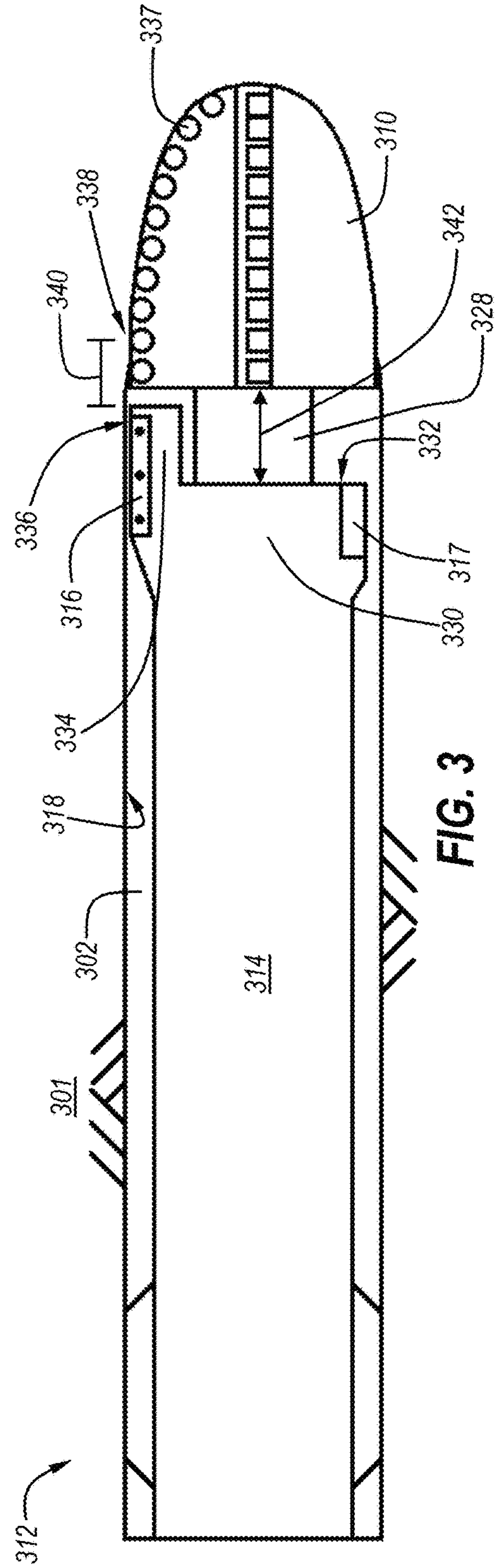

FIG. 3

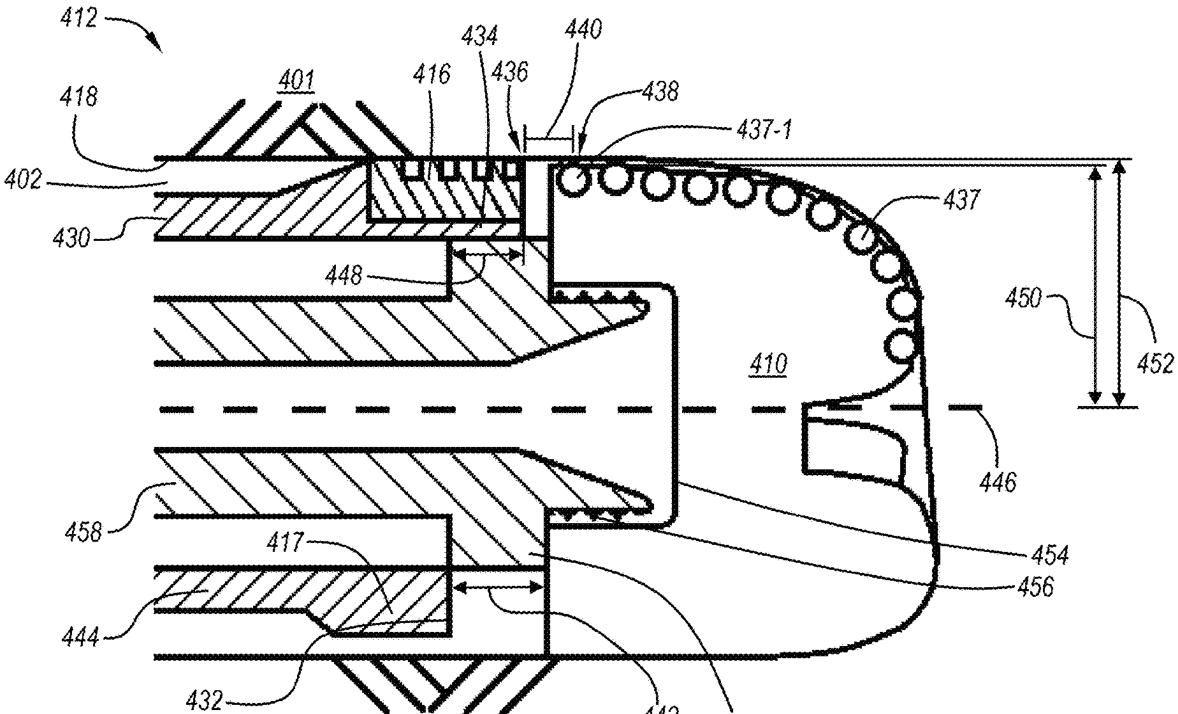
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FIG. 4

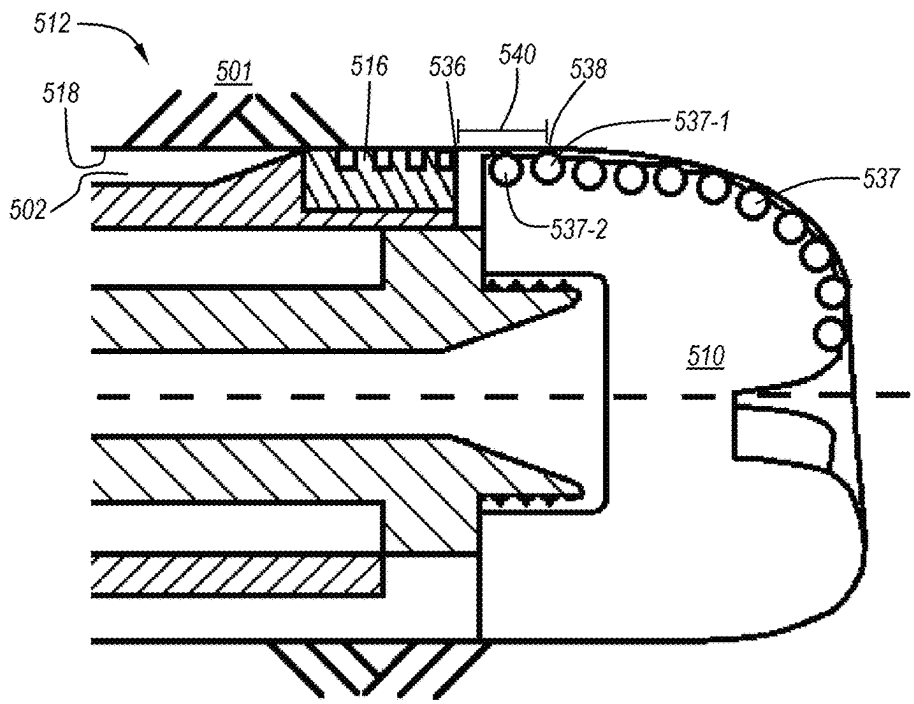
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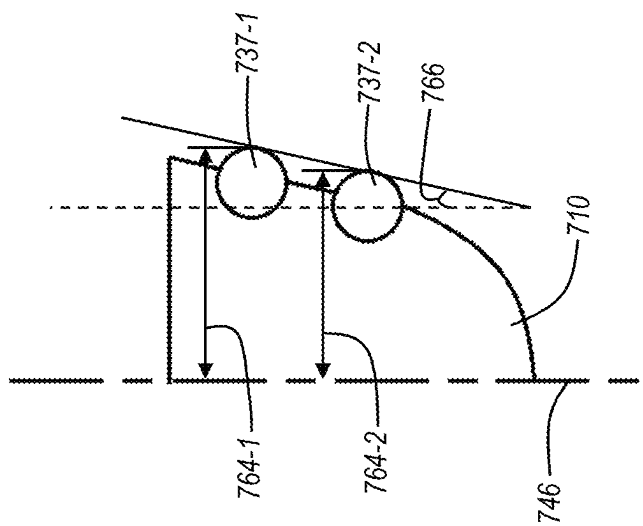
FIG. 5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737-2
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710
764-1
764-2
746

FIG. 7

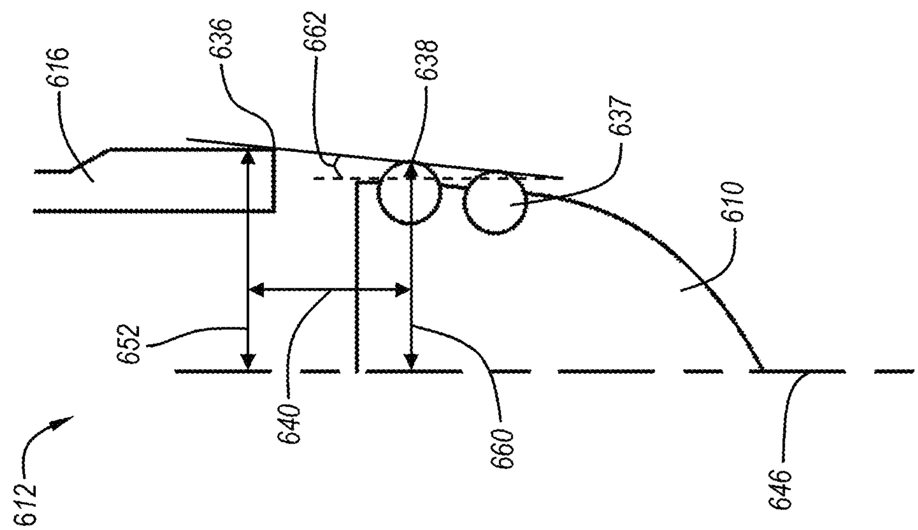
616
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FIG. 6

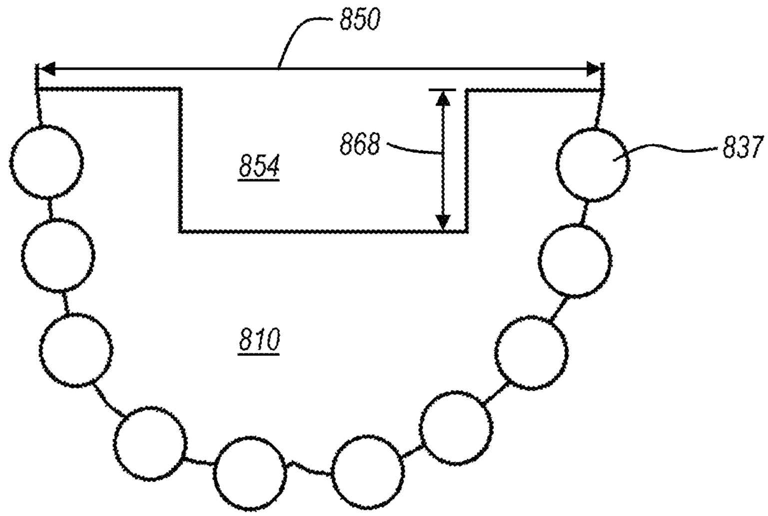

FIG. 8

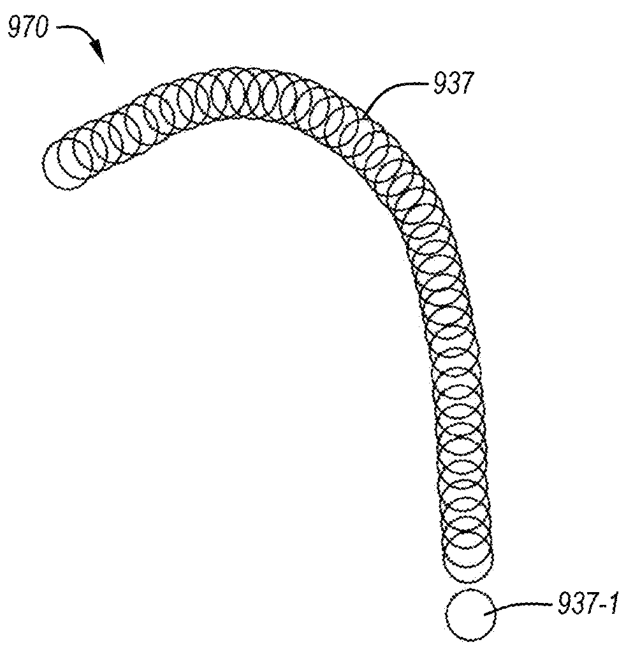

FIG. 9

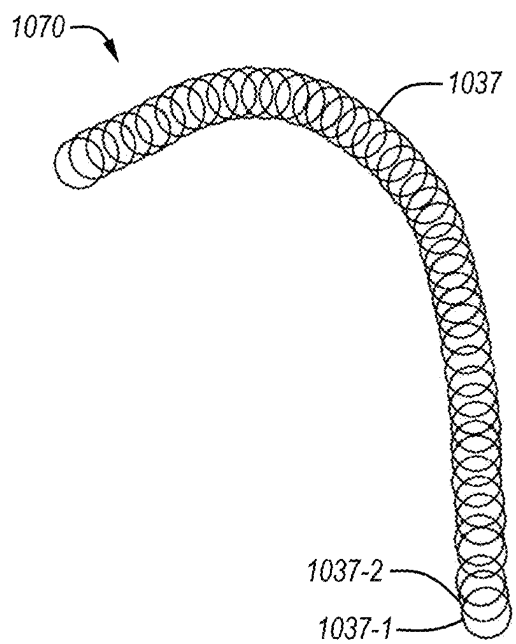

FIG. 10

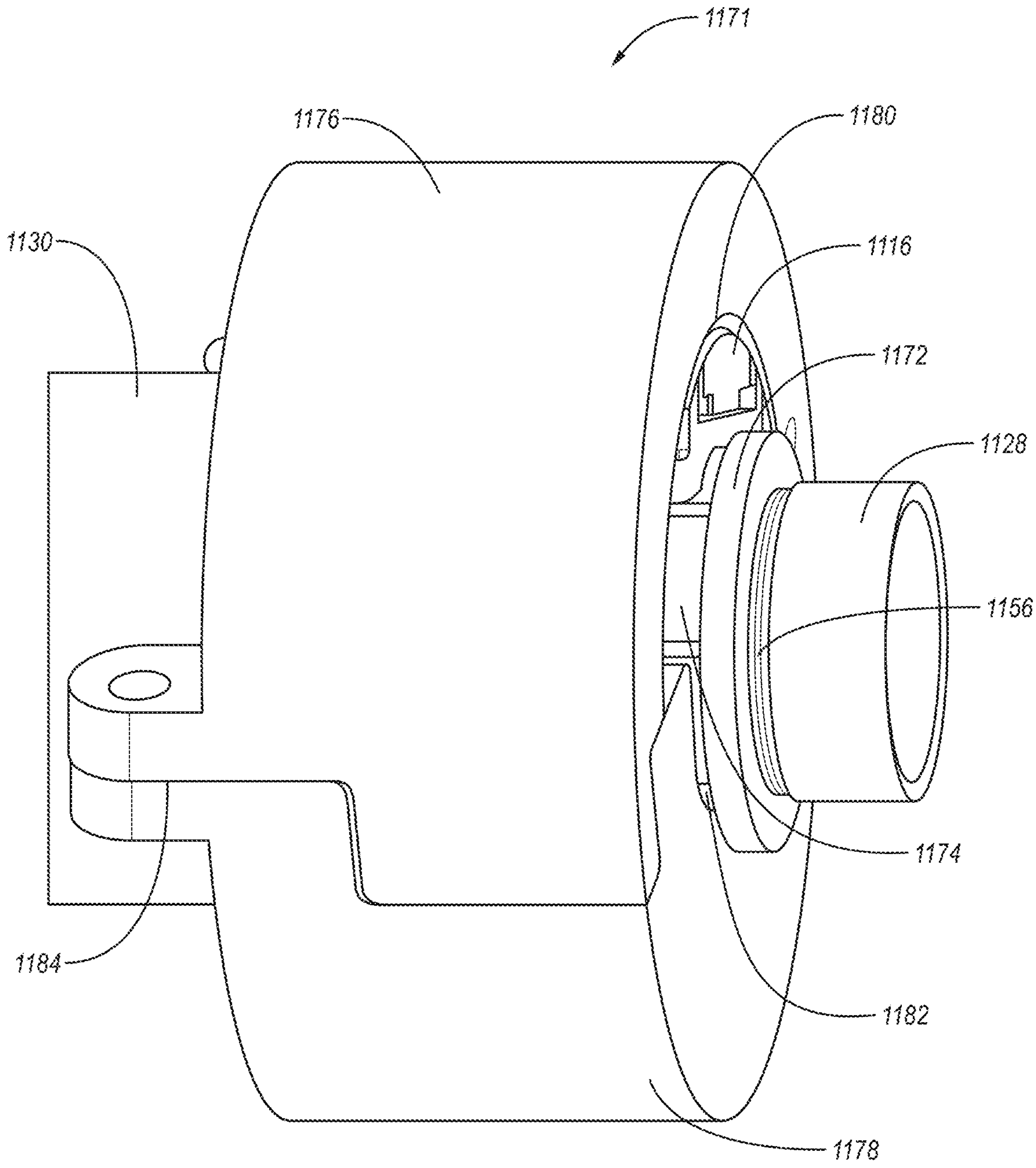

FIG. 11

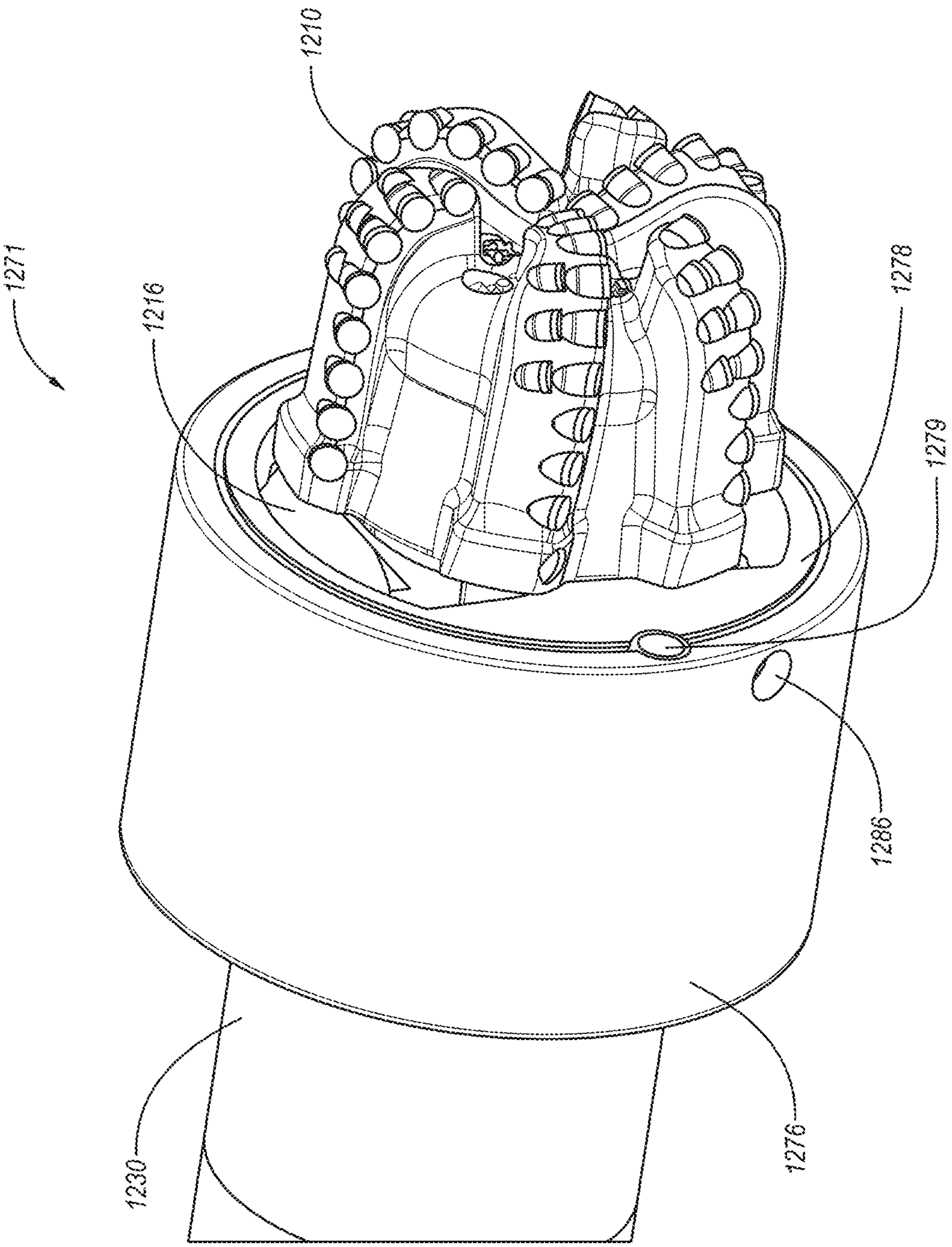

FIG. 12-1

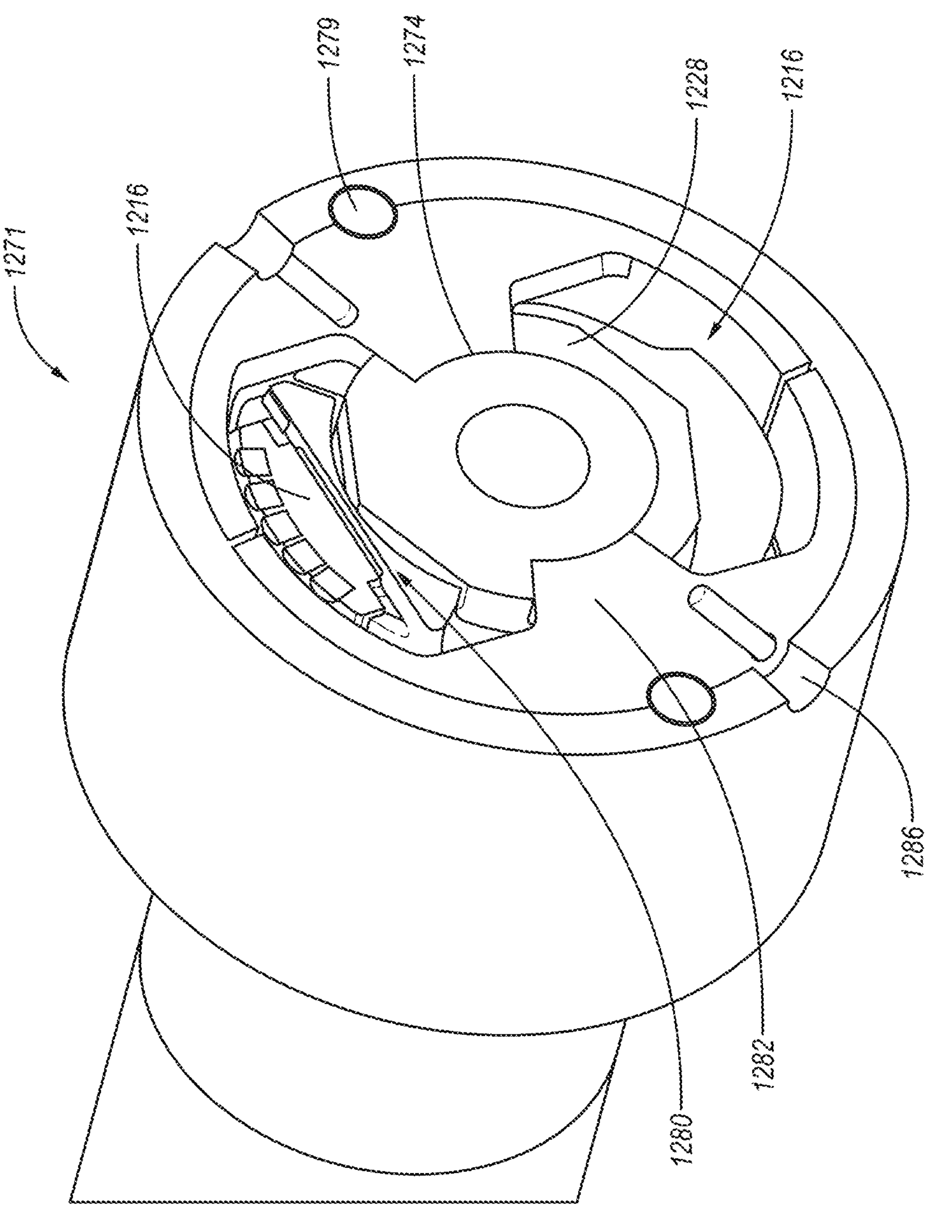

FIG. 12-2

DOWNHOLE DIRECTIONAL DRILLING TOOL

CROSS-REFERENCE TO RELATED APPLICATIONS

This application claims the benefit of, and priority to, U.S. Patent Application No. 62/805,977 filed on Feb. 15, 2019 and U.S. patent application Ser. No. 17/310,625 filed on Feb. 14, 2020 which has matured to U.S. Pat. No. 11,939,867, which is incorporated herein by this reference in its entirety.

BACKGROUND

Wellbores may be drilled into a surface location or seabed for a variety of exploratory or extraction purposes. For example, a wellbore may be drilled to access fluids, such as liquid and gaseous hydrocarbons, stored in subterranean formations and to extract the fluids from the formations. Wellbores used to produce or extract fluids may be lined with casing around the walls of the wellbore. A variety of drilling methods may be utilized depending partly on the characteristics of the formation through which the wellbore is drilled.

The wellbores may be drilled by a drilling system that drills through earthen material downward from the surface. Some wellbores are drilled vertically downward, and some wellbores have one or more curves in the wellbore to follow desirable geological formations, avoid problematic geological formations, or a combination of the two.

SUMMARY

In some aspects, a downhole tool includes a directional pad configured to contact a wellbore wall at a pad contact location and a drill bit having at least one active cutting element. The at least one active cutting element contacts the wellbore wall at a cutting element contact location, and a contact distance between the pad contact location and the cutting element contact location being 3 in. (7.6 cm) or less.

According to some aspects, a downhole tool includes a directional pad configured to contact a wellbore wall at a pad contact location and a drill bit having at least one active cutting element. A contact ratio between a bit diameter and a contact length between the pad contact location and the at least one active cutting element being greater than 3:1.

According to further aspects, a downhole tool includes a directional pad configured to contact a wellbore wall at a pad contact location and a drill bit having at least one active cutting element. A directional pad angle between the contact location and the at least one active cutting element relative to the longitudinal axis is greater than 0° and less than or equal to 5°.

Additional aspects include a downhole tool having a directional pad configured to contact a wellbore wall at a pad contact location and a drill bit having a first active cutting element and a second active cutting element. The first active cutting element is located further uphole than any other cutting element and the second active cutting element is located further uphole than any other cutting element except the first active cutting element. An angle between the first active cutting element and the second active cutting element being greater than 0° and less than or equal to 5°.

This summary is provided to introduce a selection of concepts that are further described below in the detailed description. This summary is not intended to identify key or essential features of the claimed subject matter, nor is it intended to be used as an aid in limiting the scope of the claimed subject matter. Rather, additional features and aspects of embodiments of the disclosure will be set forth in the description which follows, and in part will be obvious from the description, or may be learned by the practice of such embodiments. The features and aspects of such embodiments may be realized and obtained by means of the instruments and combinations particularly pointed out in the appended claims. These and other features will become more fully apparent from the following description and appended claims, or may be learned by the practice of such embodiments as set forth hereinafter.

BRIEF DESCRIPTION OF THE DRAWINGS

In order to describe the manner in which the above-recited and other features of the disclosure can be obtained, a more particular description will be rendered by reference to specific embodiments thereof which are illustrated in the appended drawings. For better understanding, the like elements have been designated by like reference numbers throughout the various accompanying figures. While some of the drawings may be schematic or exaggerated representations of concepts, at least some of the drawings may be drawn to scale. Understanding that the drawings depict some example embodiments, the embodiments will be described and explained with additional specificity and detail through the use of the accompanying drawings in which:

FIG. **1** is a representation of a drilling system, according to at least one embodiment of the present disclosure;

FIG. **2** is a representation of a prior art directional drilling system;

FIG. **3** is a representation of a directional drilling system, according to at least one embodiment of the present disclosure;

FIG. **4** is a cross-sectional view of a directional drilling system, according to at least one embodiment of the present disclosure;

FIG. **5** is another cross-sectional view of a directional drilling system, according to at least one embodiment of the present disclosure;

FIG. **6** is a partial side view of a bit, according to at least one embodiment of the present disclosure;

FIG. **7** is another partial side view of a bit, according to at least one embodiment of the present disclosure;

FIG. **8** is side view of a bit, according to at least one embodiment of the present disclosure;

FIG. **9** is a representation of a composite cutting profile, according to at least one embodiment of the present disclosure;

FIG. **10** is another representation of a composite cutting profile, according to at least one embodiment of the present disclosure;

FIG. **11** is a side view of an assembly tool usable to connect a drive shaft to a drill bit, according to at least one embodiment of the present disclosure;

FIG. **12-1** is a perspective view of another assembly tool usable to connect a drive shaft to a drill bit, according to at least one embodiment of the present disclosure; and

FIG. **12-2** is a perspective view of the assembly tool of FIG. **12-1**, with the drill bit removed.

DETAILED DESCRIPTION

This disclosure generally relates to devices, systems, and methods for a downhole directional drilling tool.

FIG. **1** shows one example of a drilling system **100** for drilling an earth formation **101** to form a wellbore **102**. The drilling system **100** includes a drill rig **103** used to turn a drilling tool assembly **104** which extends downward into the wellbore **102**. The drilling tool assembly **104** may include a drill string **105**, a bottomhole assembly ("BHA") **106**, and a bit **110**, attached to the downhole end of drill string **105**.

The drill string **105** may include several joints of drill pipe **108** a connected end-to-end through tool joints **109**. The drill string **105** transmits drilling fluid through a central bore and transmits rotational power from the drill rig **103** to the BHA **106**. In some embodiments, the drill string **105** may further include additional components such as subs, pup joints, etc. The drill pipe **108** provides a hydraulic passage through which drilling fluid is pumped from the surface. The drilling fluid discharges through selected-size nozzles, jets, or other orifices in the bit **110** for the purposes of cooling the bit **110** and cutting structures thereon, and for lifting cuttings out of the wellbore **102** as it is being drilled.

The BHA **106** may include the bit **110** or other components. An example BHA **106** may include additional or other components (e.g., coupled between to the drill string **105** and the bit **110**). Examples of additional BHA components include drill collars, stabilizers, measurement-while-drilling ("MWD") tools, logging-while-drilling ("LWD") tools, downhole motors, underreamers, section mills, hydraulic disconnects, jars, vibration or dampening tools, other components, or combinations of the foregoing.

In general, the drilling system **100** may include other drilling components and accessories, such as special valves (e.g., kelly cocks, blowout preventers, and safety valves). Additional components included in the drilling system **100** may be considered a part of the drilling tool assembly **104**, the drill string **105**, or a part of the BHA **106** depending on their locations in the drilling system **100**.

The bit **110** in the BHA **106** may be any type of bit suitable for degrading downhole materials. For instance, the bit **110** may be a drill bit suitable for drilling the earth formation **101**. Example types of drill bits used for drilling earth formations are fixed-cutter or drag bits. Swarf or other cuttings formed by use of a mill may be lifted to surface, or may be allowed to fall downhole. The bit **110** may be guided by a directional drilling assembly **112**.

FIG. **2** is a representation of a prior art directional drilling assembly **212** including a bit **210**. The bit **210** may be connected to a directional drilling sub **214** having one or more selectively directional pads **216** configured to contact a wall **218** of the wellbore **202**. The directional pads may be expandable, such as where the directional drilling sub **214** is a rotary steerable system. As the directional pads **216** selectively expand and contact the wall **218**, the bit **210** experiences a greater force at a bit contact location **224** on an opposite side of the wall **218**, thereby forcing a radial deflection, or dog leg, of the wellbore **202**. The bit **210** is stabilized by a contact of the stabilizer **220** with the wall **218** at a stabilizer contact location, thereby encouraging a consistent radial deflection, or dog leg severity (DLS). The DLS is increased the closer the directional pads **216** are located to the bit contact location **224**. In the shown directional drilling assembly **212** (e.g., including a rotary steerable system), the internal structural mechanics of selectively extending the directional pads **216** limits how close to the bit **210** the directional pads **216** may be placed. As shown, the distance between the directional pads **216** and the bit contact location **224** is large. For example, as shown the distance between the directional pads **216** and the bit contact location **224** is greater than 12 in. (30.5 cm).

FIG. **3** is a representation of an embodiment of a directional drilling assembly **312**. A bit **310** may be connected to a directional drilling sub **314** with a bit connection **328**. A directional pad **316** may be connected to a downhole end of the directional drilling sub **314**. The directional pad **316** may be located or housed in directional pad housing **330** located on the directional drilling sub **314**. In some embodiments, the directional pad **316** (and optionally the portion of the directional pad housing **330** supporting the directional pad **316**) may be located on or toward the lower end of the directional drilling sub **314**, and may extend past a downhole end **332** of the directional pad housing **330** and/or the directional drilling sub **314**. In particular, a distance referred to as an overhang **334** is shown as the distance the directional pad **316** (and/or associated portion of the directional pad housing **330**) extends past, or overhangs, the downhole end **332** of another portion of the directional pad housing **330**.

As shown in FIG. **3**, the portion of the directional pad housing **330** at which downhole end **332** is located may be directly opposed to the directional pad **316**; however, this is not limiting. In the same or other embodiments, the downhole end **332** may be the downhole end of a portion of the directional pad housing **330** supporting a second pad **317**. In some embodiments, the second pad **317** does not extend axially as far downhole as the direction pad **316**. In the same or other embodiments, the second pad **317** also may extend radially from the portion of the directional pad housing **330**. The amount of radial extension of the second pad **317** may vary, and in some embodiments the distance between a longitudinal axis of the directional pad housing **330** and the outer surface of the second pad **317** is less than the distance between the longitudinal axis of the directional pad housing **330** and the outer surface of the directional pad **316**. In further example embodiments, the distance between the longitudinal axis of the directional pad housing **330** and the outer surface of the second pad **317** may be less than or equal to a cutting element radius at the final cutting element contact location **338**.

In some embodiments, the second pad **317** is a discrete component attached to the directional pad housing **330**. In other embodiments, the second pad **317** is integrally formed with the directional pad housing **330** (see FIG. **4**). Further, any number of second pads **317** may be used. For instance, in at least some embodiments, the directional pad housing **330** includes or is attached to one directional pad **316** and two, three, four, or more second pads **317**.

The directional pad **316** may engage or contact the wall **318** of the wellbore **302** at a pad contact location **336**. Cutting elements **337** located on the bit **310** may engage the formation **301**, degrading or cutting the formation **301** to form the wellbore **302**. Some of the cutting elements **337** are active cutting elements **337**, meaning that they actively engage and remove the formation **301**, or cut a path through the formation **301**. At least one of the active cutting elements **337** may be at a position defining a final active cutting element contact location **338**. In some embodiments, a contact length **340** between the pad contact location **336** and the final cutting element contact location **338** may directly influence the DLS achievable using the directional drilling assembly **312**. In other words, a shorter contact length **340** may increase the DLS, and a longer contact length **340** may decrease the DLS.

In some embodiments, the bit **310** may rotate independently of, or relative to, the directional pad housing **330**. In other words, the bit **310** may be driven by a downhole motor (not shown), such as a mud turbine or a Moineau pump. The directional pad **316** may retain an absolute angular orientation (e.g., relative to a gravitational force and/or a cardinal direction such as magnetic north). As the wellbore **302** advances, the directional pad **316** may slide along the wellbore wall **318**, constantly pushing the bit **310** opposite the pad contact location **336**. Thus, the directional drilling assembly **312** may form a dog leg by slide drilling. The direction of the dog leg may be changed by rotating the directional pad housing **330**. Moreover, the magnitude of DLS can be adjusted by adjusting by switching between the drilling modes from sliding to rotating.

At least a portion of a downhole tool (such as a downhole motor drive shaft, not shown) extends from the downhole end **332** of the directional pad housing **330** to form the bit connection **328**. The bit connection **328** may extend a connection length **342**, thereby moving (e.g., extending) the directional pad housing **330**, and potentially the directional pad **316**, away from the bit **310**. In some embodiments, including an overhang **334** extending or protruding past the downhole end **332** of another portion of the directional pad housing **330** may allow the directional pad **316** to be positioned closer to the drill bit **310**, without interfering with the bit connection **328**. In this manner, the contact length **340** may be decreased, thereby increasing the DLS.

FIG. **4** is a cross-sectional view of an embodiment of a portion of a directional drilling assembly **412**. In some embodiments, the directional drilling assembly **412** may be an enlarged view of a portion of the directional drilling assembly **312** of FIG. **3**.

In FIG. **4**, a bit **410** is connected to a downhole tool **444** at a bit connection **428**. A directional pad **416** may be attached to a directional pad housing **430**, and the directional pad **416** may contact the wall **418** of the wellbore **402** at one or more pad contact locations **436**. In some embodiments, the directional pad **416** contacts the wall **418** in a single location, or at a point location, or along a single line. In other embodiments, the directional pad **416** may contact the wall **418** over an area of the directional pad **416**. In some embodiments, there is a significant contact area, such as half, a majority, or an entirety of the area of the outer surface of the directional pad **416**. The pad contact location **436** may be the downhole-most location where the directional pad **416** contacts the wall **418**.

The bit **410** may include a plurality of cutting elements **437**. Some of the cutting elements **437** may be active cutting elements **437**. Active cutting elements **437** are cutting elements that actively degrade and remove a volume of the formation **401** while the bit **410** rotates and weight on bit is applied downhole. Thus, a cutting element that is uphole of a cutting element at a greater or equal radial distance may not be considered an active cutting element **437** as the volume that could be removed by that cutting element may be removed by the time the cutting element is moved to the location of the removed rock. Rather, such a cutting element may instead be used to protect gauge, stabilize the bit, or for backreaming, rather than for active cutting while advancing the drill bit **410**.

A final active cutting element **437-1** may be the uphole-most active cutting element **437**. Accordingly, the final active cutting element **437-1** may be located further uphole than every other active cutting element **437** of the plurality of cutting elements **437**. In some examples, the final active cutting element **437-1** element may be the furthest uphole cutting element **437**. In other examples, one or more cutting elements **437**, which are not active, may be uphole of the final active cutting element **437**. For instance, one or more cutting elements **437** may be used for backreaming when the bit **410** is removed from the borehole.

The final active cutting element **437-1** may engage the formation **401** at a final cutting element contact location **438** and remove a volume of rock from the formation **401**. The final cutting element contact location **438** may be at approximately the center (e.g., longitudinal center for cylindrical shaped cutters) of the final active cutting element **437-1**, measured lengthwise down a longitudinal axis **446** of the directional drilling assembly **412**. Thus, the contact length **440** may be the distance between the pad contact location **436** and the final cutting element contact location **438**. In the illustrated embodiment, the contact length **440** may be the distance between the downhole-most location where the directional pad **416** contacts the wall **418** and the center of the final active cutting element **437-1**.

In some embodiments, the contact length **440** may be in a range having a lower value, an upper value, or lower and upper values including any of 0.25 in. (0.6 cm), 0.5 in. (1.3 cm), 0.75 in. (1.9 cm), 1.0 in. (2.5 cm), 1.25 in. (3.2 cm), 1.5 in. (3.8 cm), 1.75 in. (4.4 cm), 2.0 in. (5.1 cm), 2.25 in. (5.7 cm), 2.5 (6.4 cm), 2.75 in. (7.0 cm), 3.0 in. (7.6 cm), 4.0 in. (10.2 cm), 5.0 in. (12.7 cm), 6.0 in. (15.2 cm), 7.0 in. (17.8 cm), 8.0 in. (20.3 cm), or any value therebetween. For example, the contact length **440** may be greater than 0.25 in. (0.6 cm). In other examples, the contact length **440** may be less than 8.0 in. (2.3 cm). In still other examples, the contact length **440** may be any value in a range between 0.25 in. (0.6 cm) and 8.0 in. (2.3 cm). In other examples, the contact length **440** may be less than 6.0 in. (15.2 cm). In still other examples, the contact length **440** may be less than 3.0 in. (7.6 cm). In at least some embodiments, contact lengths **440** of less than 3.0 in. (7.6 cm) may be critical to achieve a desired DLS increase of the directional drilling assembly **412**.

In some embodiments, the maximum DLS achievable by the directional drilling assembly **412** may be in a range having a lower value, an upper value, or lower and upper values including any of 1° per 100 ft. (30 m), 2° per 100 ft. (30 m), 3° per 100 ft. (30 m), 4° per 100 ft. (30 m), 5° per 100 ft. (30 m), 6° per 100 ft. (30 m), 7° per 100 ft. (30 m), 8° per 100 ft. (30 m), 9° per 100 ft. (30 m), 10° per 100 ft. (30 m), or any value therebetween. Some analysis has further been done to show that the maximum DLS achievable by the directional assembly **412** may even exceed 10° per 100 ft. (30 m), and may even be up to 20° per 100 ft. (30 m), up to 25° per 100 ft. (30 m), up to 40° per 100 ft. (30 m), or even up to 60° per 100 ft. (30 m).

Accordingly, the maximum DLS may be greater than 1° per 100 ft. (30 m), greater than 10° per 100 ft. (30 m), greater than 20° per 100 ft. (30 m), greater than 30° per 100 ft. (30 m), or greater than 40° per 100 ft. (30 m). In the same or other examples, the maximum DLS may be less than 60° per 100 ft. (30 m), less than 50° per 100 ft. (30 m), less than 40° per 100 ft. (30 m), less than 25° per 100 ft. (30 m), less than 20° per 100 ft. (30 m), or less than 10° per 100 ft. (30 m). In still other examples, the maximum DLS may be any value in a range between 1° per 100 ft. (30 m) and 25° per 100 ft. (30 m), or any value in a range between 1° per 100 ft. (30 m) and 60° per 100 ft. (30 m).

Similar to the directional drilling assembly **312** of FIG. **3**, the directional drilling assembly **412** can include a directional pad **416** that extends a distance to have an overhang **434** relative to, and beyond, a downhole end **432** of a portion of the directional pad housing **430**. The downhole end **432** is illustrated as downhole end of a portion of the directional pad housing **430** aligned with, supporting, or part of a second pad **417**. The second pad **417** may be opposite the directional pad **416** (i.e., angularly offset by 180° in the illustrated embodiment); however, in other embodiments the second pad **417** may be offset from the directional pad **416** by less than 180° (e.g., 90° or 120°).

In some embodiments, an overhang distance **448** between the downhole end of the directional pad **416** and the downhole end **432** of the other portion of the directional pad housing **430** may be the same as, or less than, the distance **442** between the downhole end **432** and an uphole end of the drill bit **410**. For instance, the overhang **434** may extend across an entirety of a shank portion of the bit connection **428**. The shank portion of the bit connection **428** may remain outside the bit **410** when made-up to the drill bit **410** as described herein. In these or other embodiments, the contact length **440** may be zero or close to zero (e.g., less than the diameter of the final active cutting element **437-1**). In some embodiments, the contact length **440** may be a percentage of a connection distance **442**. The connection distance **442** may be the distance between the downhole end **432** of the other portion of the directional pad housing **430** and the uphole end of the drill bit **410**. In some embodiments, the connection length **442** corresponds to the length of the shank portion of the bit connection **428**.

The overhang distance **448** may be related to the connection length **442** by an overhang percentage. In some embodiments, the overhang percentage (i.e., percentage of the overhang distance **448** to the connection length **442**) may be in a range having a lower value, an upper value, or lower and upper values including any of 10%, 25%, 40%, 50%, 60%, 70%, 80%, 90%, 95%, 100%, or any value therebetween. For example, the overhang percentage may be greater than 10%. In other examples, the overhang percentage may be less than 100%. In still other examples, the overhang percentage may be any value in a range between 10% and 100%.

The bit **410** has a bit diameter, which may also be referred to as the gauge diameter. The bit diameter is twice the bit radius **450** shown in FIG. **4**. In some embodiments, the bit diameter may be any diameter used in drilling wellbores, including bit diameters between 4 in. (10.2 cm). and 24 in. (61.0 cm). In some embodiments, the bit diameter is between 6 in. (15.2 cm) and 13 in. (33.0 cm) or between 8 in. (20.3 cm) and 9 in. (22.9 cm). A contact ratio can be defined as a ratio of the bit diameter to the contact length **440**. For example, the contact ratio may be greater than 3:1. In other examples, the contact ratio may be 4:1. In still other examples, the contact ratio may be between 20:1 and 2:1. For instance, the contact ratio may be 33:2, 10:1, 9:1, 17:2, 8:1, 35:6, 5:1, 9:2; 8:3, or any other combination of bit diameter to contact length **440**. A higher contact ratio may, in some cases, increase the maximum DLS of the directional drilling assembly **412**.

The directional pad **416** of FIG. **4** has a pad radius **452** measured from the longitudinal axis **446** of the directional drilling assembly **412**. In some embodiments, the pad radius **452** is equal to or greater than the bit radius **450**. For instance, the pad radius **452** may be equal to the bit radius **450**. In other embodiments, the pad radius **452** may be greater than the bit radius **450**. For instance, the bit radius **450** may be a final active cutting element radius, and the pad radius **452** may be greater than the final active cutting element radius. In some embodiments, the pad radius **452** is between 100% and 150%, between 100% and 120%, between 101% and 115%, or between 101% and 110% of the bit radius **450**. Increasing the pad radius may increase the force applied to the wall **418** of the wellbore **402** during use, and a greater force applied to the wall **418** may increase the DLS of the directional drilling assembly **412**. In some embodiments, the directional pad **416** may be radially fixed relative to the longitudinal axis **446**. For instance, the directional pad **416** may be a fixed pad that does not extend, expand, or otherwise actuate, such that the pad radius **452** remains constant. In the same or other embodiments, the second pad(s) **417** may also be fixed pads rather than extendable or actuatable pads.

In some embodiments, the bit **410** is rotated relative to the directional pad housing **430** by the downhole tool **444**. For example, the downhole tool **444** may include a drive shaft such as a drive shaft from a downhole motor, such as a turbine or a positive displacement motor (e.g., a Moineau pump). The directional pad housing **430** may maintain a desired a rotational orientation during drilling, including an orientation relative to the force of gravity, and/or an orientation relative to magnetic or true north. For instance, the directional pad housing **430** may be used for slide drilling In some embodiments, the directional pad housing **430** and the directional pad **416** may be rotationally fixed relative to the longitudinal axis **446**. In other embodiments, the directional pad housing **430** may be rotated, thereby changing the direction of the dog leg of the directional drilling assembly **412**. In some embodiments, the directional pad **416** may be a singular directional pad **416**. In other words, the directional pad housing **430** may have a single (e.g., only one) directional pad **416**. Where the directional pad housing **430** has one or more directional pads **416**, the directional pad housing **430** may include one or more other or second pads **417** having a different configuration. The second pads **417** may not materially contribute to the directional tendencies of the directional pad housing **430**. For instance, the second pads **417** may have radial reach (and optionally reduced axial reach) relative to the directional pads **416**, such that the second pads **417** can act more like a stabilizer while the directional pad(s) **416** steer the directional drilling assembly **412**.

In some embodiments, the bit **410** may include a box connection **454**. The box connection **454** may be a hollow portion inside of the bit **410** configured to connect to the downhole tool **444** at a pin connection coupled to the bit connection **428**. In some examples, the box connection **454** and the bit connection **428** may connect via threads **456**, where the box connection **454** has the female end of the threaded connection **456**, and the bit connection **428** has the male end of the threaded connection **456**. The threaded connection may be single shoulder connection, such as an API connection. In some embodiments, the threaded connection is a double shoulder connection or premium connection, such as a proprietary connection or licensed connection. When the drill bit **410** is made-up to the downhole tool **444**, fluid flowing through a central bore **458** of the downhole tool **444** (e.g., in the drive shaft) may flow into the drill bit **410** and through one or more ports or nozzles in the body of the drill bit **410**. The threaded connection **456** may allow sufficient room in the drill bit body to allow the ports or nozzles that will provide total flow sufficient to clean and cool the cutting structure of the drill bit **410** while drilling formation.

FIG. **5** is another cross-sectional view of an embodiment of a directional drilling assembly **512**. In some embodiments, a directional pad **516** may contact or engage a wall **518** of a wellbore **502** at a pad contact location **536**. A bit **510** has a plurality of cutting elements **537**, some of which are active cutting elements **537** which engage and remove formation **501**. A final active cutting element **537-1** may be an uphole-most active cutting element **537**. In other words, the final active cutting element **537-1** may be the furthest uphole active cutting element **537** of all active cutting elements **537**. As shown in FIG. **5**, in at least some embodiments, the final active cutting element **537-1** may not be the furthest uphole cutting element **537**. One or more inactive cutting elements **537-2** may be located uphole of the final active cutting element **537-1**. In some embodiments, the one or more inactive cutting elements **537-2** may be located on the same blade as the final active cutting element **537-1**. In other embodiments, the one or more inactive cutting elements **537-2** may be located on a different blade from the final active cutting element **537-1**. Thus, as described above, a contact length **540** may be measured from the pad contact location **536** to a final active cutting element contact location **538**.

FIG. **6** is a representation of a section of a directional drilling assembly **612**, according to at least one embodiment of the present disclosure. A directional pad **616** may be located uphole of a bit **610** that includes a plurality of cutting elements. In some embodiments, the plurality of cutting elements include an active gauge cutting element **638** and an active adjacent-to-gauge cutting element **637**. The directional pad **616** optionally has an outermost surface at a pad radius **652** greater than that the gauge radius **660** at an outermost cutting tip of the active gauge cutting element **638**, as measured relative to a longitudinal axis **646** of the bit **610**. Thus, a directional pad angle **662** may exist between the pad contact location **636** and the final cutting element contact location of the active gauge cutting element **638**, relative to the longitudinal axis **646**. In some embodiments, the directional pad angle **662** may be in a range having a lower value, an upper value, or lower and upper values including any of 0.0°, 0.1°, 0.5°, 1.0°, 1.5°, 2.0°, 2.5°, 3.0°, 3.5°, 4.0°, 4.5°, 5.0°, or any value therebetween. For example, the directional pad angle **662** taper radially inwardly from the directional pad **616** to the active gauge cutting element **638** at an angle greater than 0.0° and/or less than 5.0°. In still other examples, the directional pad angle **662** may be any value in a range between and/or between and including 0.0° and 5.0°. In other embodiments, the angle may be greater than 5.0°. In some embodiments, relatively higher directional pad angles **662** may increase the DLS as compared to relatively smaller directional pad angles **662** that can decrease the DLS.

In some embodiments, the contact length **640** may be less than 3 in. (7.6 cm), and the directional pad angle **662** may be between 0.0° and 5.0° or between 0.5° and 3.5°. The combination of contact length **640** and directional pad angle **662** may further increase the DLS and/or improve control over the accuracy or precision of the DLS.

FIG. **7** is a representation of a section of a bit **710**, according to at least one embodiment of the present disclosure. The bit **710** may include a plurality of cutting elements, including an active gauge cutting element(s) **737-1** and an active adjacent-to-gauge cutting element(s) **737-2**. In FIG. **7**, the cutting elements **737-1**, **737-2** illustrate cutting element positions in a composite cutting profile in which all cutting elements are aligned in the same blade. Thus, multiple discrete cutting elements can be located at a same cutting element position and would show as a single cutting element. Where multiple cutting elements show as a single cutting element in the cutting profile view, the cutting element position is considered to have redundancy.

In some embodiments, the active gauge cutting element(s) **737-1** is located farther uphole than every other cutting element of the plurality of cutting elements (or farther uphole than every other active cutting element of the plurality of cutting elements), including the active adjacent-to-gauge cutting element(s) **737-2**. The active adjacent-to-gauge cutting element(s) **737-2** are located farther uphole than every other cutting element of the plurality of cutting elements except the active gauge cutting element(s) **737-1**. In some embodiments, an active gauge cutting element **737-1** and an active adjacent-to-gauge cutting element **737-2** are located on the same blade of the bit **710**. In other embodiments, a blade may include one, but not both, of an active gauge cutting element **737-1** and an active adjacent-to-gauge cutting element **737-2**.

The active gauge cutting element **737-1** has a first cutting element radius **764-1** relative to a longitudinal axis **746** of the bit **710**. The active adjacent-to-gauge cutting element **737-2** has a second cutting element radius **764-2** relative to the longitudinal axis **746**. In some embodiments, the second cutting element radius **764-2** may be different than the first cutting element radius **764-1**. In this manner, a cutting element angle **766** is formed between the first cutting element **737-1** and the second cutting element **737-2**. In some embodiments, the cutting element angle **766** may be in a range having a lower value, an upper value, or lower and upper values including any of 0.05°, 0.1°, 0.5°, 1.0°, 1.5°, 2.0°, 2.5°, 3.0°, 3.5°, 4.0°, 4.5°, 5.0°, or any value therebetween. For example, the cutting element angle **766** may be greater than 0.05°. In other examples, the cutting element angle **766** may be less than 5.0°. In still other examples, the cutting element angle **766** may be any value in a range between 0.0° and 5.0°, between 0.1° and 4°, or between 1° and 3°.

In some embodiments, the second cutting element radius **764-2** may be smaller than the first cutting element radius **764-1**. Thus, a negative cutting element angle **766** is formed. In other words, the gauge of the bit may have a negative, or inward, taper in a downhole direction. A negative cutting element angle **766** may enable the upper cutting elements, on the gauge of a drill bit, to more fully engage the formation (e.g., formation **301** of FIG. **3**) when the directional pad (e.g., directional pad **316** of FIG. **3**) causes an increased force against one side of the bit **710**.

In some embodiments, the cutting element angle **766** may be the same as the directional pad angle (e.g., directional pad angle **662** of FIG. **6**). This may further enable an even force distribution or cutting volume across multiple active cutting elements **737-1**, **737-2** as the bit **710** is pushed by the directional pad. In other embodiments, the cutting element angle **766** may be greater than or less than the directional pad angle.

FIG. **8** is a representation of an embodiment of a bit **810**. The bit **810** may include a box connection **854** having a box length **868**. In some embodiments, the box length **868** may be in a range having a lower value, an upper value, or lower and upper values including any of 0.5 in. (1.3 cm), 0.75 in. (1.9 cm), 1.0 in. (2.5 cm), 1.25 in. (3.2 cm), 1.5 in. (3.8 cm), 1.75 in. (4.5 cm), 2.0 in. (5.1 cm), 2.25 in. (5.7 cm), 2.5 in. (6.4 cm), 2.75 in. (7.0 cm), 3.0 in. (7.6 cm), 5.0 in. (12.7 cm), or any value therebetween. For example, the box length **868** may be greater than 0.5 in. (1.3 cm). In other examples, the box length **868** may be less than 3.0 in. (7.6 cm). In still other examples, the box length **868** may be any value in a range between 0.5 in. (1.3 cm) and 5.0 in. (12.6 cm), or between 1.0 in. (2.5 cm) and 3.0 in. (7.6 cm).

The bit **810** has a bit diameter **850**. In some embodiments, a bit ratio may be the ratio of the bit diameter **850** to the box length **868**. In some embodiments, the bit ratio may be between 2.5 and 5. For instance, the bit ratio may be 8.5:2

(17:4), 8:2.5 (16:5), 8.75:2.75 (35:11), 8.5:2.75 (34:11), 3:1, or any other ratio of bit diameter **850** to box length **868**. In some embodiments, the bit ratio may be greater than 3:1 or less than 4.5:1. In some embodiments, the box length **868** may be at least partially dependent on the bit diameter **850**. A longer box length **868** may be stronger, and a larger bit diameter **850** may incur greater forces on the box connection **854**, thereby impacting the bit ratio. In some embodiments, however, the type of formation (e.g., formation **301** of FIG. **3**) to be drilled through may affect the bit ratio. In some embodiments, at least one cutting element **837** (e.g., an active cutting element) of the bit **810** may axially overlap the box connection **854**. In other words, at an axial position along a longitudinal axis of the bit **810**, both a portion of the bod connection **854** and at least one cutting element **837** may be located. Thus, a radius extending through at least one cutting element **837** may extend through a portion of the box connection **854**. Although the bit diameter **850** is shown relative to the bit body, in other embodiments, the bit diameter **850** is measured in relation to the gauge diameter of the bit (i.e., based on the cutting tip of the cutting elements **837**).

FIG. **9** is a representation of a composite cutting profile **970**, according to at least one embodiment of the present disclosure. The composite cutting profile **970** may be utilized in any of the bits described herein, specifically regarding the bits described in reference to FIG. **3** through FIG. **8**. The composite cutting profile **970** is a representation of the radial and axial cutting position of each cutting element **937** on a bit (e.g., bit **310** of FIG. **3**). The composite cutting profile **970** may include a final active cutting element **937-1** located in a gauge region of the bit. In some embodiments, the final active cutting element **937-1** may engage and remove a volume of material on a path through the formation (e.g., the formation **301** of FIG. **3**) while the wellbore (e.g., wellbore **302** of FIG. **3**) is being advanced in a downhole direction. The final active cutting element **937-1** (or cutting elements at the final active cutting element position **937-1**) may be further uphole than cutting elements **937** at any other cutting element position on the cutting profile **970**. Thus, the final active cutting element(s) **937-1** may be located the farthest uphole of any cutting elements **937**. The final active cutting element(s) **937-1** may not be a backreaming cutting element, or configured to cut primarily while the bit is being pulled out of the wellbore, or to merely maintain the gauge diameter cut by a cutting element that is in a farther downhole position. Rather, the final active cutting element **937-1** may be configured to engage and cut a volume of the formation while the wellbore is advancing.

In some embodiments, the bit may include redundant or backup final active cutting elements **937-1**. In some embodiments, a bit having multiple blades may have multiple, redundant cutting elements **937** located in the same radial and longitudinal position on each of two or more different blades. Cutting elements **937** located in the same longitudinal position on different blades are redundant because they cut the same rotational path. In this manner, placing multiple final active cutting elements **937-1** in the same radial and longitudinal position on multiple blades provides redundancy that can help improve the life of the final active cutting elements **937-1**, which may experience greater wear than other cutting elements, as they can each actively remove a reduced total volume.

As may be seen in the composite cutting profile **970**, if redundant or backup final active cutting elements **937-1** are placed on every blade of the bit (and if the blades do not include trailing cutters at other positions), none of the other cutting elements **937** may be at a position in the cutting profile **970** that overlaps the position of the final active cutting element **937-1**. Placing redundant or backup final active cutting elements **937-1** on some but fewer than each of the blades (e.g., half, one-third, one-quarter, every other blade, and so forth), may allow some overlap of the positions of active cutting elements with the final active cutting element(s) **937-1** on the cutting profile **970**.

FIG. **10** is a representation of a composite cutting profile **1070**, according to at least one embodiment of the present disclosure. The composite cutting profile **1070** may be utilized in any of the bits described herein, specifically regarding the bits described in reference to FIG. **3** through FIG. **8**. The composite cutting profile **1070** is a representation of the cutting path of each cutting element **1037** on a bit (e.g., bit **310** of FIG. **3**). The composite cutting profile **1070** may include a first final active cutting element **1037-1** located in a gauge region of the bit. The first final active cutting element **1037-1** may be the uphole-most active cutting element **1037** (or multiple first final active cutting elements **1037-1**). A second final active cutting element **1037-2** actively engages and removes formation farther uphole than any other cutting element **1037** except the first final active cutting element(s) **1037-1**.

The first final active cutting element **1037-1** and the second final active cutting element **1037-2** may overlap in the cutting profile **1070** and may thus be located on different blades of the bit, or at leading and trailing positions on a single blade. Thus, in at least some embodiments, the first final active cutting element **1037-1** and the second final active cutting element **1037-2** may have overlapping cutting paths. In this manner, the cutting element angle (e.g., cutting element angle **766**) may be fine-tuned along a length of the bit.

FIG. **11** illustrates an example assembly tool **1171** according to at least one embodiment of the present disclosure. A motor, drive shaft, or bias unit connection **1128** may include a connection shoulder **1172** and a plurality of keyed features **1174**. In some embodiments, the connection **1128** may include eight flats spaced around the outer surface of the connection **1128**, which flats cooperatively define a surface or connection feature allowing the assembly tool **1171** to hold the connection **1128** in place while a bit (e.g., bit **310**, **410**, **510**, **610**, **710**, **810**) can be rotated and secured thereto. In other embodiments, the assembly tool **1171** can be used to rotate the connection **1128** while another suitable device holds the bit in place.

While the connection **1128** is shown as having eight flats that define the keyed features **1174**, the connection **1128** of the motor, drive shaft, or bias unit may have any suitable feature. In other embodiments, for instance, the bit connection **1128** may include 1, 2, 3, 4, 5, 6, 7, or more than 8 flats or other keyed features **1174**. In some embodiments, the keyed features may include protrusions, recesses, slots, or holes that can be engaged by the assembly tool. Any suitable keyed features **1174** may be evenly spaced around a circumference of the connection **1128**. In other embodiments, the keyed features **1174** may be unevenly spaced around the circumference of the connection **1128**. For example, a larger slot or flat may correspond to a specific location on the assembly tool **1171**, thereby aligning the connection **1128** with the assembly tool **1171**.

The connection **1128** may be a pin connection that is coupled to a box connection (e.g., box connection **454** of FIG. **4**) of a bit (e.g., bit **410** of FIG. **4**). The connection **1128** may be attached to, or part of, a downhole tool, such as a drive shaft from a downhole motor, such as a turbine or a positive displacement motor (e.g., a Moineau pump). The downhole tool is optionally internal to, and rotatable relative to, a directional pad housing **1130**. A directional pad **1116** (and optionally the portion of the directional pad housing **1130** supporting the directional pad **1116**) may extend past, or overhang, the downhole end (e.g., downhole end **432** of FIG. **4**) of the directional pad housing **1130**. In some embodiments, the directional pad **1116** (and optionally the portion of the directional pad housing **1130** supporting the directional pad **1116**) may extend over one or more of the plurality of keyed features **1174** and/or the connection shoulder **1172**. The connection **1128** may include a threaded connection **1156**, which may connect to corresponding threads on a bit.

To securely fasten the bit to the connection **1128** via the threaded connection **1156**, the bit is rotated relative to the bit connection **1128** (or vice versa). The assembly tool **1171** may clamp onto the connection **1128** to restrict or even prevent the drive shaft or other downhole tool from rotating while the bit is fastened to the connection **1128**. In the illustrated embodiment, the assembly tool has an upper portion **1176** and a lower portion **1178**. The upper portion **1176** and the lower portion **1178** may have generally U-shaped radial cross-sectional areas to clamp around the connection **1128**. The upper portion **1176** may have an upper cut-out **1180** that mates with a portion of one or more of the directional pad **1116**, the directional pad housing **1130**, or the keyed features **1174**. For instance, the upper cut-out **1180** may be sized to pass over the connection **1128** and the directional pad **1116**. One or more portions of the upper cut-out **1180** may then be sized and position to restrict rotation of the directional pad **1116** or directional pad housing **1130** when positioned as shown in FIG. **11**. The lower portion **1178** may have a lower cut-out **1182** sized to connect to the connection **1128** at the plurality of keyed features **1174**. The lower cut-out **1182** may include one or more protrusions or engaging surfaces sized to mate, engage, or interlock with one or more of the plurality of keyed features **1174**. In some embodiments, the lower cut-out **1182** may include an indentation for a second pad (e.g., second pad **417** of FIG. **4**) that may be supported by the directional pad housing **1130**.

The upper portion **1176** and the lower portion **1178** may connect at an interface **1184**. The interface **1184** may be used to clamp or otherwise secure the upper portion **1176** and the lower portion **1178** together (e.g., with a compressive force). The interface **1184** may be a bolted connection, a threaded connection, or any other connection or interface that aligns or secures the upper portion **1176** to the lower portion **1178** in the closed configuration shown in FIG. **11**. In other words, when the interface **1184** is used to secure the upper portion **1176** to the lower portion **1178**, the assembly tool **1171** clamps to the connection **1128** over the directional pad **1116**. In this manner, with the one or more engaging surfaces of the lower portion **1178** mating or interlocking with one or more of the keyed features **1174**, and potentially the surfaces of the upper cut-out **1180** restricting rotation of the directional pad **1116**, the connection **1128** is rotationally fixed relative to the assembly tool **1171**. Thus, a bit may be attached and tightened to the connection **1128** using the assembly tool **1171** to provide a counter-rotation force.

FIGS. **12-1** and **12-2** illustrate another example assembly tool **1271** according to at least one embodiment of the present disclosure. A motor, drive shaft, or bias unit connection **1228** may include a plurality of keyed features **1274**. A shoulder may also be included as shown in FIG. **11**, but is optional and may not be included in some embodiments.

In some embodiments, the connection **1228** includes two slots spaced around the outer surface of the connection **1228**, which slots cooperatively define a surface or connection feature allowing the assembly tool **1271** to hold the connection **1228** in place while a bit **1210** can be rotated and secured thereto, or rotated around the bit **1210** while the bit **1210** is held in place. In contrast to the flats **1174** shown in FIG. **11**, the slots **1274** may be deeper, and allow the application of higher torque. Further, in some embodiments, one or more flats or other surfaces may also be provided on the connection **1228** along with the slots **1274**. In FIG. **12-2**, for instance, two slots and four flats may be seen, although any suitable number of slots, flats, or the like can be used. Accordingly, as described herein, any suitable keyed features **1274** may be used, and may include one keyed feature, or multiple keyed features evenly or unevenly spaced around a circumference of the connection **1228**.

The connection **1228** may be a pin connection that is coupled to a box connection (e.g., box connection **454** of FIG. **4**) of the bit **1210**. The connection **1228** may be attached to, or part of, a downhole tool, such as a drive shaft from a downhole motor, such as a turbine or a positive displacement motor. The downhole tool is optionally internal to, and rotatable relative to, a directional pad housing **1230**. A directional pad **1216** (and optionally the portion of the directional pad housing **1230** supporting the directional pad **1216**) may extend past, or overhang, the downhole end (e.g., downhole end **432** of FIG. **4**) of the directional pad housing **1230**, as described herein. In some embodiments, the directional pad **1216** (and optionally the portion of the directional pad housing **1230** supporting the directional pad **1216**) extends at least partially over, and is axially aligned with, one or more of the plurality of keyed features **1274**, flats, and/or the connection shoulder or pin connection of the connection **1228**. The connection **1228** may include a threaded connection, which may connect to corresponding threads on the bit **1210**.

To securely fasten the bit **1210** to the connection **1228** via the threaded connection, the bit **1210** is rotated relative to the bit connection **1228** (or vice versa). The assembly tool **1271** may fit around the connection **1228**, and optionally into the keyed features **1274**, to restrict or even prevent the drive shaft or other downhole tool from rotating while the bit **1210** is fastened to the connection **1228**. In the illustrated embodiment, the assembly tool has an outer portion **1276** and an inner portion **1278**. The inner portion **1278** may fit within the outer portion **1276**, and is optionally rotationally secured therein using one or more pins **1279** or other fasteners. In some embodiments, there may be a single portion, rather than separate inner and outer portions **1276**, **1278**. As further shown, one or more openings **1280** may be formed in the outer portion **1276** and optionally the inner portion **1278**. These openings may be used as a grip so that the assembly tool **1271** can be held in place. Of course, other mechanisms such as grips, keyed features, or the like may be used to otherwise hold the assembly tool **1271** in place.

The inner portion **1278** may have a cut-out **1280** that mates with a portion of one or more of the directional pad **1216**, the directional pad housing **1230**, or even keyed features (e.g., flats) of the connection **1228**. For instance, the cut-out **1280** may be sized to pass over the connection **1228** and the directional pad **1216**. One or more portions of the cut-out **1280** may then be sized and position to restrict rotation of the directional pad **1216** or directional pad housing **1230** when positioned as shown in FIG. **12-2**. The inner portion **1278** may also have an engagement portion **1282** sized to connect to the connection **1228** at the plurality of slots **1274**. The engagement portion **1282** may include one or more protrusions or engaging surfaces sized to mate, engage, fit within, or interlock with one or more of the plurality of keyed features **1274**. In some embodiments, the inner portion **1278** may be symmetrical, or otherwise include a second cut-out **1280**. The second cut-out **1280** may provide an opening for a second pad that may be supported by the directional pad housing **1230**. In this manner, with the one or more engaging features **1282** (e.g., tabs) of the inner portion **1278** mating or interlocking with one or more of the keyed features **1274**, and potentially the surfaces of the cut-out **1280** restricting rotation of the directional pad **1216**, the connection **1228** is rotationally fixed relative to the assembly tool **1271**. Thus, the bit **1210** may be attached and tightened to the connection **1228** using the assembly tool **1271** to provide a counter-rotation force.

The embodiments of the downhole directional drilling tool have been primarily described with reference to wellbore drilling operations; the downhole directional drilling tool described herein may be used in applications other than the drilling of a wellbore. In other embodiments, downhole directional drilling tool according to the present disclosure may be used outside a wellbore or other downhole environment used for the exploration or production of natural resources. For instance, downhole directional drilling tool of the present disclosure may be used in a borehole used for placement of utility lines. Accordingly, the terms "wellbore," "borehole" and the like should not be interpreted to limit tools, systems, assemblies, or methods of the present disclosure to any particular industry, field, or environment.

One or more specific embodiments of the present disclosure are described herein. These described embodiments are examples of the presently disclosed techniques. Additionally, in an effort to provide a concise description of these embodiments, not all features of an actual embodiment may be described in the specification. It should be appreciated that in the development of any such actual implementation, as in any engineering or design project, numerous embodiment-specific decisions will be made to achieve the developers' specific goals, such as compliance with system-related and business-related constraints, which may vary from one embodiment to another. Moreover, it should be appreciated that such a development effort might be complex and time consuming, but would nevertheless be a routine undertaking of design, fabrication, and manufacture for those of ordinary skill having the benefit of this disclosure.

The articles "a," "an," and "the" are intended to mean that there are one or more of the elements in the preceding descriptions. It should be understood that references to "one embodiment" or "an embodiment" of the present disclosure are not intended to be interpreted as excluding the existence of additional embodiments that also incorporate the recited features. For example, to simplify the discussion herein, some features are described with respect to particular embodiments. However, any features that are not mutually exclusive can be combined or interchanged. For instance, features of FIGS. **3-5** are interchangeable. Additionally, any other elements described in relation to an embodiment herein may be combinable with any element of any other embodiment described herein. For instance, the cutting profiles of any of FIGS. **6**, **7**, **9**, and **10** may be defined by any of the bits of FIG. **3-5** or **8**. Similarly, the bit of FIG. **8** may be used in any of the downhole tools of FIGS. **3-5**.

Numbers, percentages, ratios, or other values stated herein are intended to include that value, and also other values that are "about" or "approximately" the stated value, as would be appreciated by one of ordinary skill in the art encompassed by embodiments of the present disclosure. A stated value should therefore be interpreted broadly enough to encompass values that are at least close enough to the stated value to perform a desired function or achieve a desired result. The stated values include at least the variation to be expected in a suitable manufacturing or production process, and may include values that are within 5%, within 1%, within 0.1%, or within 0.01% of a stated value.

A person having ordinary skill in the art should realize in view of the present disclosure that equivalent constructions do not depart from the spirit and scope of the present disclosure, and that various changes, substitutions, and alterations may be made to embodiments disclosed herein without departing from the spirit and scope of the present disclosure. Equivalent constructions, including functional "means-plus-function" clauses are intended to cover the structures described herein as performing the recited function, including both structural equivalents that operate in the same manner, and equivalent structures that provide the same function. It is the express intention of the applicant not to invoke means-plus-function or other functional claiming for any claim except for those in which the words 'means for' appear together with an associated function. 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.

The terms "approximately," "about," and "substantially" as used herein represent an amount close to the stated amount that still performs a desired function or achieves a desired result. For example, the terms "approximately," "about," and "substantially" may refer to an amount that is within less than 5% of, within less than 1% of, within less than 0.1% of, and within less than 0.01% of a stated amount. Further, it should be understood that any directions or reference frames in the preceding description are merely relative directions or movements. For example, any references to "up" and "down" or "above" or "below" are merely descriptive of the relative position or movement of the related elements.

The present disclosure may be embodied in other specific forms without departing from its spirit or characteristics. The described embodiments are to be considered as illustrative and not restrictive. The scope of the disclosure is, therefore, indicated by the appended claims rather than by the foregoing description. Changes that come within the meaning and range of equivalency of the claims are to be embraced within their scope.

What is claimed is:

1. A downhole tool, comprising:

a directional pad configured to contact a wellbore wall at a contact location; and

a drill bit having a longitudinal axis and at least one active cutting element, a directional pad angle between the contact location and the at least one active cutting element relative to the longitudinal axis being greater than 0° and less than or equal to 5°.

2. The downhole tool of claim **1**, a contact length between the contact location and the at least one active cutting element being up to 3 in. (7.6 cm).

3. The downhole tool of claim **1**, the drill bit having a bit diameter and a ratio between the bit diameter and a contact length between the at least one active cutting element and the contact location being greater than 3:1.

4. The downhole tool of claim **1**, the at least one active cutting element engaging a formation.

5. The downhole tool of claim **1**, the directional pad being coupled to a directional pad housing having one or more second pads, the directional pad extending longitudinally past a downhole end of the one or more second pads of the housing.

6. The downhole tool of claim **1**, the directional pad having a pad radius that is greater than a cutting element radius of each of the at least one active cutting elements.

7. The downhole tool of claim **1**, the at least one active cutting element removing a volume of formation as the drill bit is rotated with weight-on-bit.

8. The downhole tool of claim **7**, the at least one active cutting element including at least two redundant cutting elements, each cutting element of the at least two redundant cutting elements removing a portion of the volume of formation as the drill bit is rotated.

9. The downhole tool of claim **1**, the at least one active cutting element axially overlapping a box connection in the drill bit, the box connection being configured to connect the drill bit to a motor or other subcomponent of the downhole tool.

10. The downhole tool of claim **1**, the at least one active cutting element including a first active cutting element at a first position and a second active cutting element at a second position, the first active cutting element being located farther uphole than every other active cutting element of the at least one active cutting element that is not at the first position, the second active cutting element being located further uphole than every other active cutting element of the at least one active cutting element except any cutting element at the first position, a cutting element angle between the first active cutting element and the second active cutting element relative to the longitudinal axis being greater than 0° and less than or equal to 5°.

11. The downhole tool of claim **10**, the directional pad angle and the active cutting element angle being the same.

12. The downhole tool of claim **1**, wherein the directional pad is coupled to a directional tool and a drill bit including a box connection coupled to a pin connection of the directional tool.

13. The downhole tool of claim **12**, wherein the at least one active cutting element axially overlaps the box connection.

14. The downhole tool of claim **12**, wherein the directional tool further comprises a drive shaft internal to a directional pad housing coupled to the directional pad, and wherein the box connection further comprises threads coupled to a threaded pin connection of the drive shaft.

15. A downhole tool, comprising:

a directional pad configured to contact a wellbore wall at a pad contact location; and

a drill bit comprising a longitudinal axis and having at least one active cutting element, the at least one active cutting element contacting the wellbore wall at a cutting element contact location, a contact length between the cutting element contact location and the pad contact location being up to 3 in. (7.6 cm), wherein the at least one active cutting element comprises one or more active cutting elements at a first position that is further uphole than every other active cutting element of the at least one active cutting element;

wherein the at least one active cutting element includes at least two redundant cutting elements at the same radial and longitudinal position; and

having a contact pad angle between the contact location and the at least one active cutting element relative to the longitudinal axis being greater than 0° and less than or equal to 5°.

16. A downhole tool, comprising:

a housing;

a directional pad coupled to the housing and configured to contact a wellbore wall at a pad contact location; and

a drill bit comprising a longitudinal axis and having at least one active cutting element and a bit diameter, a contact ratio of a diameter of the bit to a contact length between the at least one active cutting element and the contact location being greater than 3:1, wherein the at least one active cutting element is positioned at a first position located further uphole than every other active cutting element of the at least one cutting element that is not at the first position;

wherein the at least one active cutting element includes at least two redundant cutting elements at the same radial position; and

a contact pad angle between the contact location and the at least one active cutting element relative to the longitudinal axis being greater than 0° and less than or equal to 5°.

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