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(54) **MULTI-ZONE ACTUATION SYSTEM USING WELLBORE DARTS**

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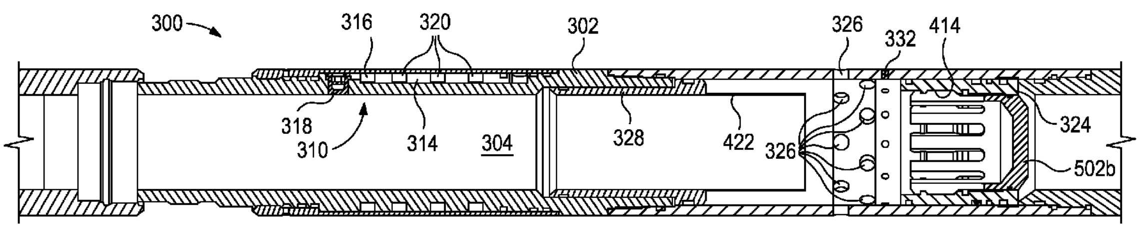
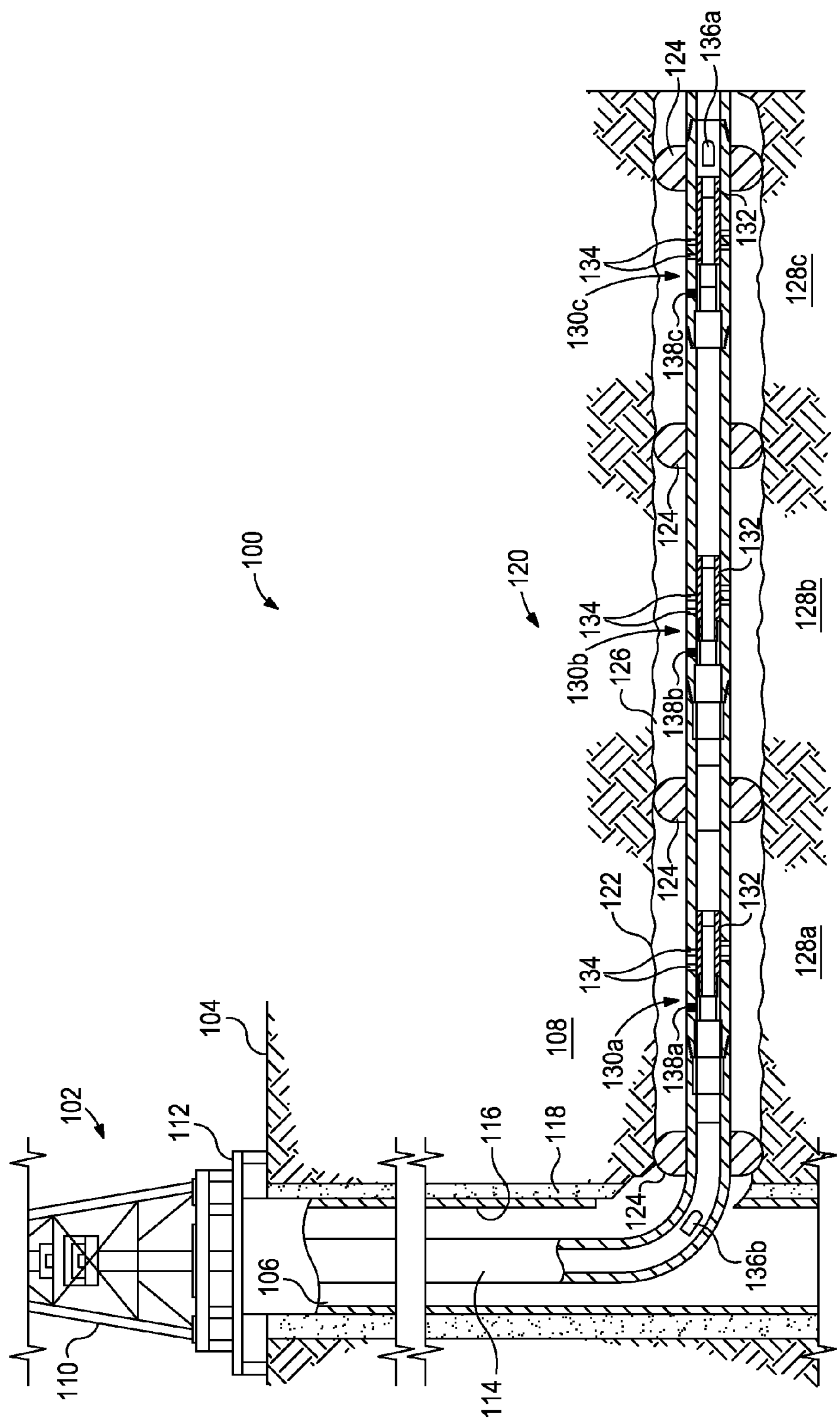
(57) **ABSTRACT**

Sliding sleeve assemblies including a completion body with an inner flow passageway and one or more ports enabling fluid communication between the inner flow passageway and an exterior of the completion body. A sliding sleeve is arranged within the completion body and has a sleeve mating profile defined on an inner surface, the sliding sleeve being movable between a closed position, where the one or more ports are occluded, and an open position, where the one or more ports are exposed. A plurality of wellbore darts are used and each has a body and a common dart profile that is matable with the sleeve mating profile. One or more sensors are positioned on the completion body to detect the plurality of wellbore darts traversing the inner flow passageway. An actuation sleeve is arranged within the completion body and movable to expose the sleeve mating profile.

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138a
138b
138c

FIG. 1

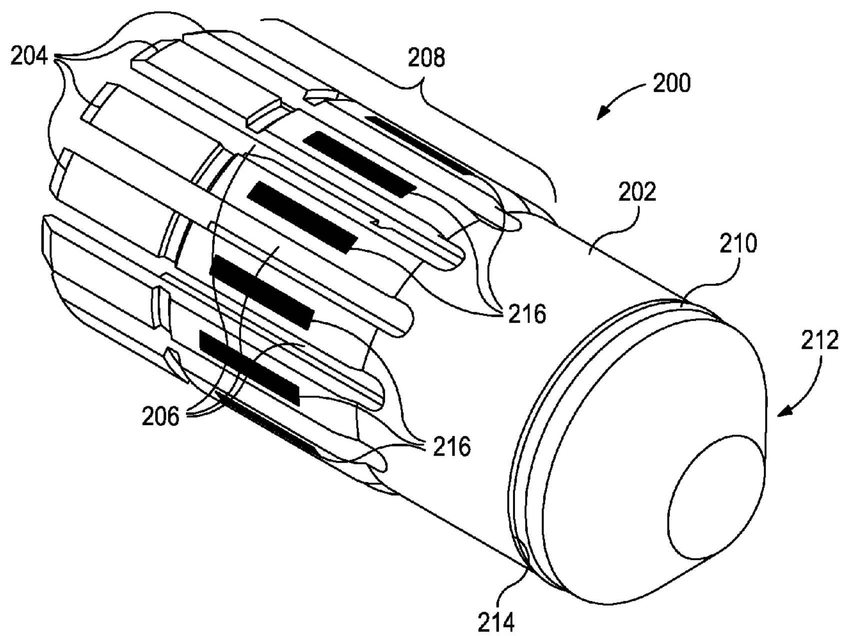
204
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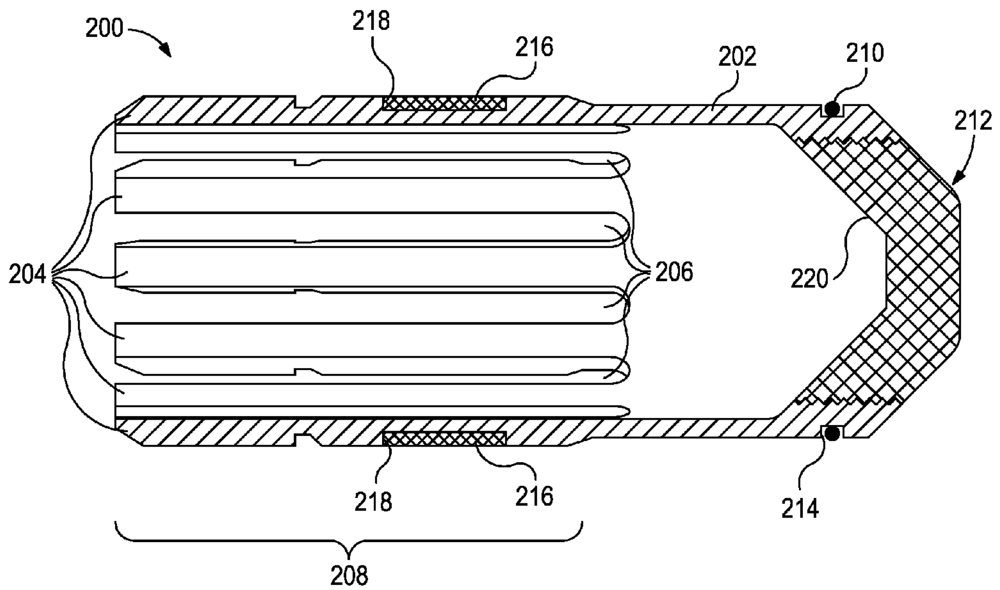
FIG. 2A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208

FIG. 2B

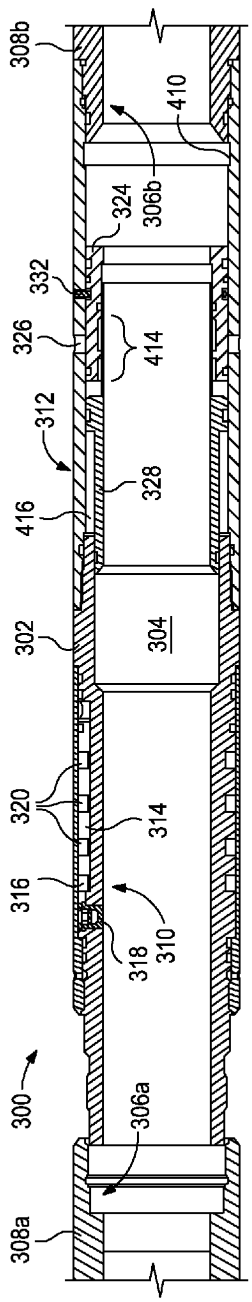
308b
410
306b
324
332
326
414
312
416
328
302
304
320
314
316
318
310
300
306a
308a

FIG. 3A

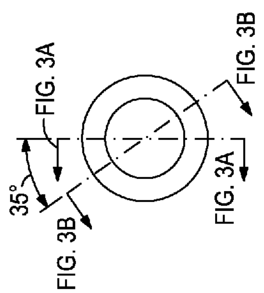
FIG. 3A
FIG. 3B
35°
FIG. 3B
FIG. 3A

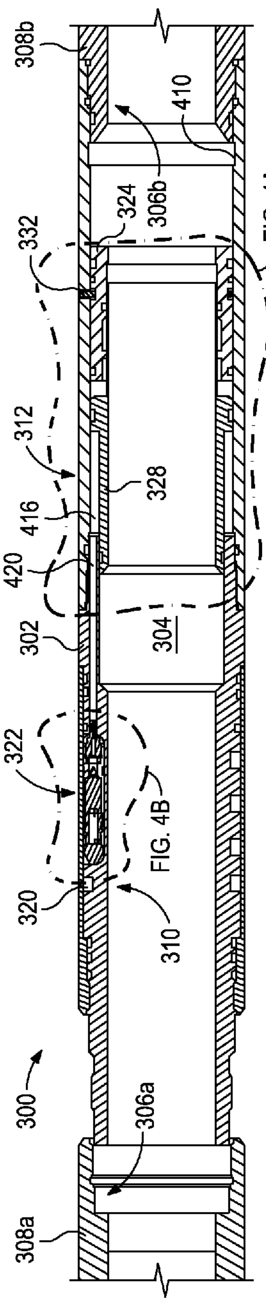
308b
410
306b
324
332
FIG. 4A
312
328
416
420
302
304
322
FIG. 4B
320
310
300
306a
308a

FIG. 3B

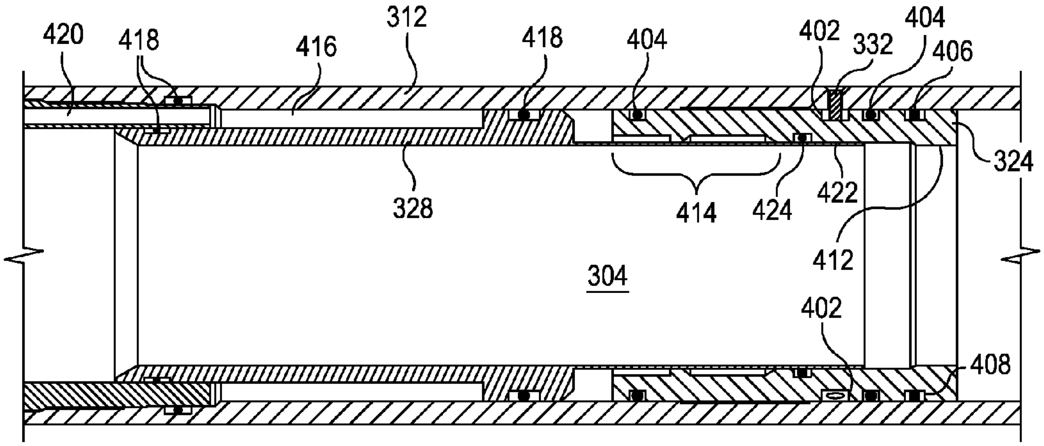

FIG. 4A

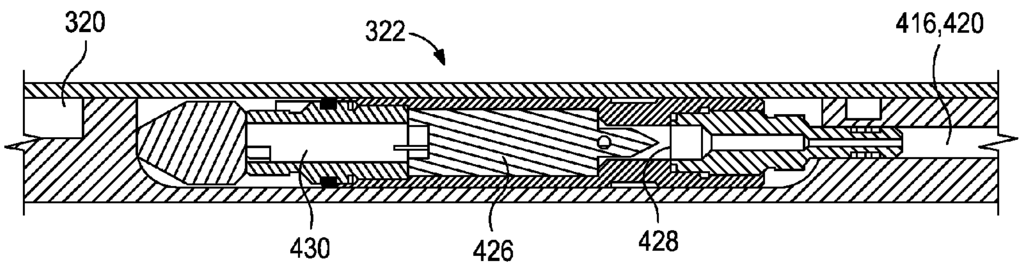

FIG. 4B

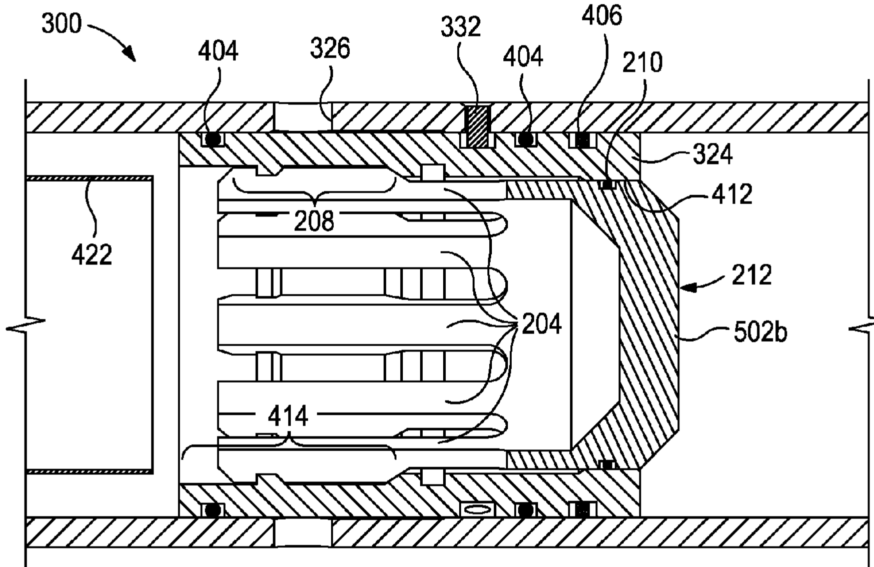

FIG. 6

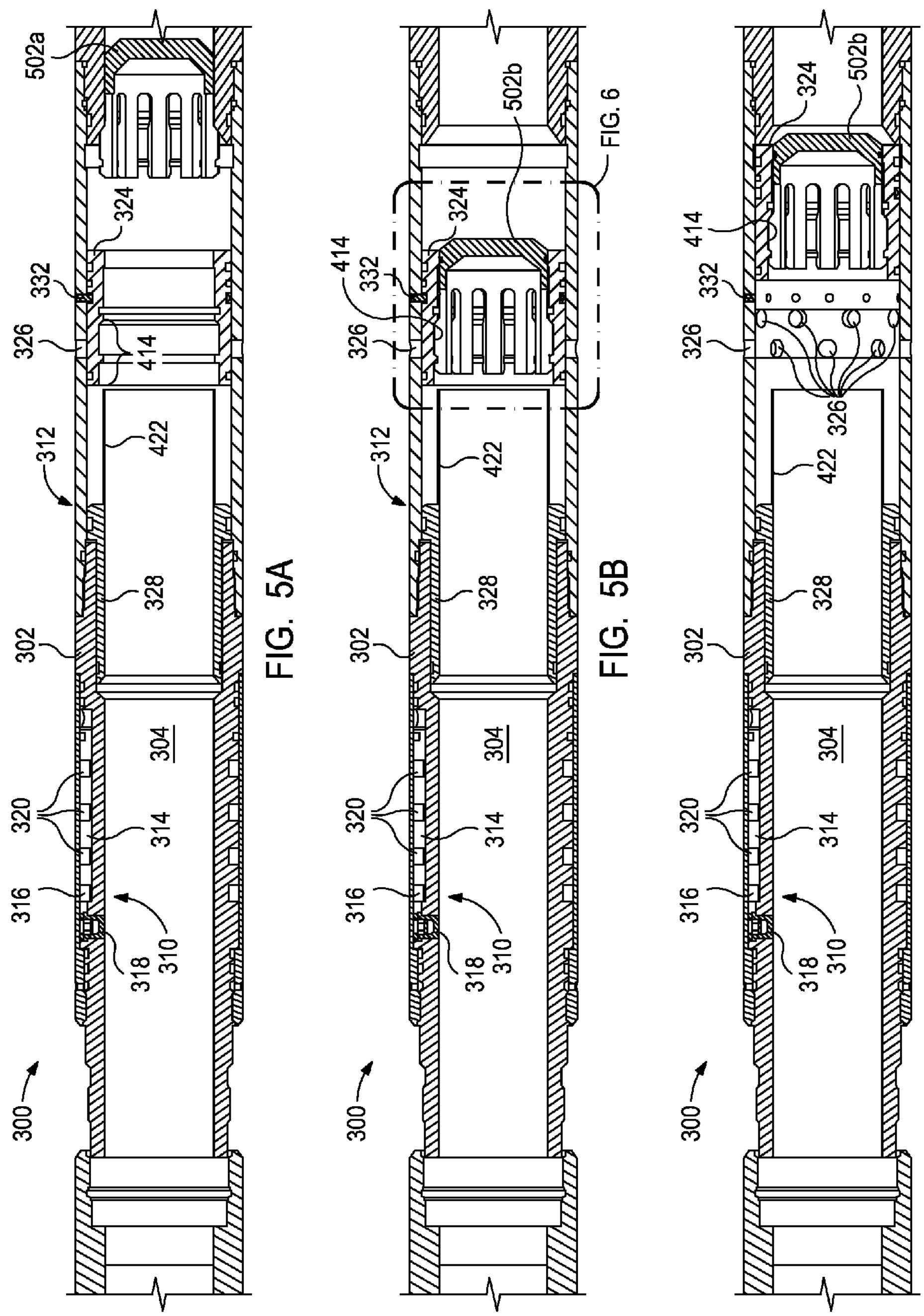

FIG. 5A

FIG. 5B

FIG. 5C

MULTI-ZONE ACTUATION SYSTEM USING WELLBORE DARTS

BACKGROUND

[0001] The present disclosure relates generally to wellbore operations and, more particularly, to a multi-zone actuation system that detects wellbore darts in carrying out multiple-interval stimulation of a wellbore.

[0002] In the oil and gas industry, subterranean formations penetrated by a wellbore are often fractured or otherwise stimulated in order to enhance hydrocarbon production. Fracturing and stimulation operations are typically carried out by strategically isolating various zones of interest (or intervals within a zone of interest) in the wellbore using packers and the like, and then subjecting the isolated zones to a variety of treatment fluids at increased pressures. In a typical fracturing operation for a cased wellbore, the casing cemented within the wellbore is first perforated to allow conduits for hydrocarbons within the surrounding subterranean formation to flow into the wellbore. Prior to producing the hydrocarbons, however, treatment fluids are pumped into the wellbore and the surrounding formation via the perforations, which has the effect of opening and/or enlarging drainage channels in the formation, and thereby enhancing the producing capabilities of the well.

[0003] Today, it is possible to stimulate multiple zones during a single stimulation operation by using onsite stimulation fluid pumping equipment. In such applications, several packers are introduced into the wellbore and each packer is strategically located at predetermined intervals configured to isolate adjacent zones of interest. Each zone may include a sliding sleeve that is moved to permit zonal stimulation by diverting flow through one or more tubing ports occluded by the sliding sleeve. Once the packers are appropriately deployed, the sliding sleeves may be selectively shifted open using a ball and baffle system. The ball and baffle system involves sequentially dropping wellbore projectiles from a surface location into the wellbore. The wellbore projectiles, commonly referred to as "frac balls," are of predetermined sizes configured to seal against correspondingly sized baffles or seats disposed within the wellbore at corresponding zones of interest. The smaller frac balls are introduced into the wellbore prior to the larger frac balls, where the smallest frac ball is designed to land on the baffle furthest in the well, and the largest frac ball is designed to land on the baffle closest to the surface of the well. Accordingly, the frac balls isolate the target sliding sleeves, from the bottom-most sleeve moving uphole. Applying hydraulic pressure from the surface serves to shift the target sliding sleeve to its open position.

[0004] Thus, the ball and baffle system acts as an actuation mechanism for shifting the sliding sleeves to their open position downhole. When the fracturing operation is complete, the balls can be either hydraulically returned to the surface or drilled up along with the baffles in order to return the casing string to a full bore inner diameter. As can be appreciated, at least one shortcoming of the ball and baffle system is that there is a limit to the maximum number of zones that may be fractured owing to the fact that the baffles are of graduated sizes.

BRIEF DESCRIPTION OF THE DRAWINGS

[0005] The following figures are included to illustrate certain aspects of the present disclosure, and should not be viewed as exclusive embodiments. The subject matter disclosed is capable of considerable modifications, alterations, combinations, and equivalents in form and function, without departing from the scope of this disclosure.

[0006] FIG. **1** illustrates an exemplary well system that can embody or otherwise employ one or more principles of the present disclosure, according to one or more embodiments.

[0007] FIGS. **2**A and **2**B illustrate an exemplary wellbore projectile in the form of a wellbore dart, according to one or more embodiments of the present disclosure.

[0008] FIGS. **3**A and **3**B illustrate cross-sectional side views of an exemplary sliding sleeve assembly, according to one or more embodiments.

[0009] FIG. **4**A is an enlarged view of the sliding sleeve and the actuation sleeve of FIGS. **3**A and **3**B, as indicated by the labeled dashed line provided in FIG. **3**B, according to one or more embodiments.

[0010] FIG. **4**B is an enlarged view of an exemplary actuation device, as indicated by the labeled dashed line provided in FIG. **3**B, according to one or more embodiments.

[0011] FIGS. **5**A-**5**C illustrate progressive cross-sectional side views of the assembly of FIGS. **3**A and **3**B, according to one or more embodiments.

[0012] FIG. **6** is an enlarged view of a wellbore dart mating with a sliding sleeve, as indicated by the dashed area of FIG. **5**B, according to one or more embodiments.

DETAILED DESCRIPTION

[0013] The present disclosure relates generally to wellbore operations and, more particularly, to a multi-zone actuation system that detects wellbore darts in carrying out multiple-interval stimulation of a wellbore.

[0014] The embodiments described herein disclose sliding sleeve assemblies that are able to detect wellbore darts and actuate a sliding sleeve upon detecting a predetermined number of wellbore darts having dart profiles defined thereon. Once a predetermined number of wellbore darts has been detected, an actuation sleeve may be actuated to expose a sleeve mating profile defined on a sliding sleeve. After the sleeve mating profile is exposed, a subsequent wellbore dart introduced downhole may be able to locate and mate with its dart profile with the sleeve mating profile. Upon applying fluid pressure uphole from the subsequent wellbore dart, the sliding sleeve may then be moved to an open position, where flow ports become exposed and facilitate fluid communication into a surrounding subterranean environment for wellbore stimulation operations. The presently disclosed embodiments, therefore, provide intervention-less wellbore stimulation methods and systems.

[0015] Referring to FIG. **1**, illustrated is an exemplary well system **100** which can embody or otherwise employ one or more principles of the present disclosure, according to one or more embodiments. As illustrated, the well system **100** may include an oil and gas rig **102** arranged at the Earth's surface **104** and a wellbore **106** extending therefrom and penetrating a subterranean earth formation **108**. Even though FIG. **1** depicts a land-based oil and gas rig **102**, it will be appreciated that the embodiments of the present disclosure are equally well suited for use in other types of rigs, such as offshore platforms, or rigs used in any other geographical location. In other embodiments, the rig **102** may be replaced with a wellhead installation, without departing from the scope of the disclosure.

[0016] The rig **102** may include a derrick **110** and a rig floor **112**. The derrick **110** may support or otherwise help manipulate the axial position of a work string **114** extended within the wellbore **106** from the rig floor **112**. As used herein, the term "work string" refers to one or more types of connected lengths of tubulars or pipe such as drill pipe, drill string, landing string, production tubing, coiled tubing combinations thereof, or the like. The work string **114** may be utilized in drilling, stimulating, completing, or otherwise servicing the wellbore **106**, or various combinations thereof.

[0017] As illustrated, the wellbore **106** may extend vertically away from the surface **104** over a vertical wellbore portion. In other embodiments, the wellbore **106** may otherwise deviate at any angle from the surface **104** over a deviated or horizontal wellbore portion. In other applications, portions or substantially all of the wellbore **106** may be vertical, deviated, horizontal, and/or curved. Moreover, use of directional terms such as above, below, upper, lower, upward, downward, uphole, downhole, and the like are used in relation to the illustrative embodiments as they are depicted in the figures, the upward direction being toward the top of the corresponding figure and the downward direction being toward the bottom of the corresponding figure, the uphole direction being toward the heel or surface of the well and the downhole direction being toward the toe or bottom of the well.

[0018] In an embodiment, the wellbore **106** may be at least partially cased with a casing string **116** or may otherwise remain at least partially uncased. The casing string **116** may be secured within the wellbore **106** using, for example, cement **118**. In other embodiments, the casing string **116** may be only partially cemented within the wellbore **106** or, alternatively, the casing string **116** may be omitted from the well system **100**, without departing from the scope of the disclosure. The work string **114** may be coupled to a completion assembly **120** that extends into a branch or lateral portion **122** of the wellbore **106**. As illustrated, the lateral portion **122** may be an uncased or "open hole" section of the wellbore **106**. It is noted that although FIG. **1** depicts the completion assembly **120** as being arranged within the lateral portion **122** of the wellbore **106**, the principles of the apparatus, systems, and methods disclosed herein may be similarly applicable to or otherwise suitable for use in wholly vertical wellbore configurations. Consequently, the horizontal or vertical nature of the wellbore **106** should not be construed as limiting the present disclosure to any particular wellbore **106** configuration.

[0019] The completion assembly **120** may be deployed within the lateral portion **122** of the wellbore **106** using one or more packers **124** or other wellbore isolation devices known to those skilled in the art. The packers **124** may be configured to seal off an annulus **126** defined between the completion assembly **120** and the inner wall of the wellbore **106**. As a result, the subterranean formation **108** may be effectively divided into multiple intervals or "pay zones" **128** (shown as intervals **128***a*, **128***b*, and **128***c*) which may be stimulated and/or produced independently via isolated portions of the annulus **126** defined between adjacent pairs of packers **124**. While only three intervals **128***a-c* are shown in FIG. **1**, those skilled in the art will readily recognize that any number of intervals **128***a-c* may be defined or otherwise used in the well system **100**, including a single interval, without departing from the scope of the disclosure.

[0020] The completion assembly **120** may include one or more sliding sleeve assemblies **130** (shown as sliding sleeve assemblies **130***a*, **130***b*, and **130***c*) arranged in, coupled to, or otherwise forming integral parts of the work string **114**. As illustrated, at least one sliding sleeve assembly **130***a-c* may be arranged in each interval **128***a-c*, but those skilled in the art will readily appreciate that more than one sliding sleeve assembly **130***a-c* may be arranged in each interval **128***a-c*, without departing from the scope of the disclosure. It should be noted that, while the sliding sleeve assemblies **130***a-c* are shown in FIG. **1** as being employed in an open hole section of the wellbore **106**, the principles of the present disclosure are equally applicable to completed or cased sections of the wellbore **106**. In such embodiments, a cased wellbore **106** may be perforated at predetermined locations in each interval **128***a-c* to facilitate fluid conductivity between the interior of the work string **114** and the surrounding intervals **128***a-c* of the formation **108**.

[0021] Each sliding sleeve assembly **130***a-c* may be actuated in order to provide fluid communication between the interior of the work string **114** and the annulus **126** adjacent each corresponding interval **128***a-c*. As depicted, each sliding sleeve assembly **130***a-c* may include a sliding sleeve **132** that is axially movable within the work string **114** to expose one or more ports **134** defined through the work string **114**. Once exposed, the ports **134** may facilitate fluid communication between the annulus **126** and the interior of the work string **114** such that stimulation and/or production operations may be undertaken in each corresponding interval **128***a-c* of the formation **108**.

[0022] According to the present disclosure, in order to move the sliding sleeve **132** of a given sliding sleeve assembly **130***a-c* to its open position, and thereby expose the corresponding ports **134**, one or more wellbore darts **136** (shown as a first wellbore dart **136***a* and a second wellbore dart **136***b*) may be introduced into the work string **114** and conveyed downhole toward the sliding sleeve assemblies **130***a-c*. The wellbore darts **136** may be conveyed through the work string **114** and to the completion assembly **120** by any known technique. For example, the wellbore darts **136** can be dropped through the work string **114** from the surface **104**, pumped by flowing fluid through the interior of the work string **114**, self-propelled, conveyed by wireline, slickline, coiled tubing, etc.

[0023] Each wellbore dart **136** may be detectable by one or more sensors **138** (shown as sensors **138***a*, **138***b*, and **138***c*) associated with each sliding sleeve assembly **130***a-c*. In some embodiments, for instance, the wellbore darts **136** may exhibit known magnetic properties, and/or produce a known magnetic field, pattern, or combination of magnetic fields, which is/are detectable by the sensors **138***a-c*. In such cases, each sensor **138***a-c* may be capable of detecting the presence of the magnetic field(s) produced by the wellbore darts **136** and/or one or more other magnetic properties of the wellbore darts **136**. Suitable magnetic sensors **138***a-c* can include, but are not limited to, magneto-resistive sensors, Hall-effect sensors, conductive coils, combinations thereof, and the like. In some embodiments, permanent magnets can be combined with one or more of the sensors **138***a-c* in order to create a magnetic field that is disturbed by the wellbore darts **136**, and a detected change in the magnetic field can be an indication of the presence of the wellbore darts **136**.

[0024] Moreover, in some embodiments, each sensor **138***a-c* may include a barrier (not shown) positioned between the sensor **138***a-c* and the wellbore darts **136**. The barrier may comprise a relatively low magnetic permeability material and may be configured to allow magnetic signals to pass therethrough and isolate pressure between the sensor **138***a-c* and the wellbore darts **136**. Additional information on such a barrier as used in magnetic detection can be found in U.S. Patent Pub. No. 2013/0264051. In other embodiments, a magnetic shield (not shown) may be positioned either on the wellbore darts **136** or near the sensors **138***a-c* to "short circuit" magnetic fields emitted by the wellbore darts **136** and thereby reduce the amount of remnant magnetic fields that may be detectable by the sensors **138***a-c*. In such embodiments, the magnetic field may be pulled toward materials that have a high magnetic permeability, which effectively shields the sensors **138***a-c* from the remnant magnetic fields.

[0025] In other embodiments, one or more of the sensors **138***a-c* may be capable of detecting radio frequencies emitted by the wellbore darts **136**. In such embodiments, the sensors **138***a-c* may be radio frequency (RF) sensors or readers capable of detecting a radio frequency identification (RFID) tag secured to or otherwise forming part of the wellbore darts **136**. The RF sensors **138***a-c* may be configured to sense the RFID tags as the wellbore darts **136** traverse the work string **114** and encounter the RF sensors **138***a-c*. In at least one embodiment, the RF sensors **138***a-c* may be micro-electromechanical systems (MEMS) or devices capable of sensing radio frequencies. In such cases, the MEMS sensors may include or otherwise encompass an RF coil and thereby be used as the sensors **138***a-c*. The RF sensor **138***a-c* may alternatively be a near field communication (NFC) sensor capable of establishing radio communication with a corresponding dummy tag arranged on the wellbore darts **136**. When the dummy tags come into proximity of the RF sensors **138***a-c*, the RF sensors **138***a-c* may register the presence of the wellbore darts **136**.

[0026] In yet other embodiments, the sensors **138***a-c* may be a type of mechanical switch or the like that may be mechanically manipulated through physical contact with the wellbore darts **136** as they traverse the work string **114**. In some cases, for instance, the mechanical sensors **138***a-c* may be ratcheting or mechanical counting devices or switches disposed near each sleeve **132**. Upon physically contacting and otherwise interacting with the wellbore darts **136**, the mechanical sensors **138***a-c* may be configured to generate and send corresponding signals indicative of the same to an adjacent actuation device (not shown in FIG. **1**), as will be described below. In some embodiments, the mechanical sensors **138***a-c* may be spring loaded or otherwise configured such that after the wellbore dart **136** has passed (or following a certain time period thereafter) the switch may autonomously reset itself. As will be appreciated, such a resettable embodiment may allow the mechanical sensors **138***a-c* to physically interact with multiple wellbore darts **136**.

[0027] Each sensor **138***a-c* may be connected to associated electronic circuitry (not shown in FIG. **1**) configured to determine whether the associated sensor **138***a-c* has positively detected a wellbore dart **136**. For instance, in the case where the sensors **138***a-c* are magnetic sensors, the sensors **138***a-c* may detect a particular or predetermined magnetic field, or pattern or combination of magnetic fields, or other magnetic properties of the wellbore darts **136**, and the associated electronic circuitry may have the predetermined magnetic field(s) or other magnetic properties programmed into non-volatile memory for comparison. Similarly, in the case where the sensors **138***a-c* are RF sensors, the sensors **138***a-c* may detect a particular RF signal from the wellbore darts **136**, and the associated electronic circuitry may either count the RF signals or compare the RF signals with RF signals programmed into its non-volatile memory.

[0028] Once a wellbore dart **136** is positively detected by the sensors **138***a-c*, the associated electronic circuitry may acknowledge and count the detection instance and, if appropriate, trigger actuation of the corresponding sliding sleeve assembly **130***a-c* using one or more associated actuation devices (not shown in FIG. **1**). In some embodiments, for example, actuation of the associated sliding sleeve assembly **130***a-c* may not be triggered until a predetermined number or combination of wellbore darts **136** has been detected by the given sensors **138***a-c*. Accordingly, each sensor **138***a-c* records and counts the passing of each wellbore dart **136** and, once a predetermined number of wellbore darts **136** is detected by a given sensor **138***a-c*, the corresponding sliding sleeve assembly **130***a-c* may then be actuated in response thereto.

[0029] The completion assembly **120** may include as many sliding sleeve assemblies **130***a-c* as required to undertake a desired fracturing or stimulation operation in the subterranean formation **108**. The electronic circuitry of each sliding sleeve assembly **130***a-c* may be programmed with a predetermined wellbore dart **136** "count." Upon reaching or otherwise registering the predetermined wellbore dart **136** count, each sliding sleeve assembly **130***a-c* may then be actuated. More particularly, the electronic circuitry associated with the third sliding sleeve assembly **130***c* may require the detection and counting of one wellbore dart **136** before actuating the third sliding sleeve assembly **130***c*; the electronic circuitry associated with the second sliding sleeve assembly **130***b* may require the detection and counting of two wellbore darts **136** before actuating the second sliding sleeve assembly **130***b*; and the electronic circuitry associated with the first sliding sleeve assembly **130***a* may require the detection and counting of three wellbore darts **136** before actuating the first sliding sleeve assembly **130***a*.

[0030] In the illustrated embodiment, the first wellbore dart **136***a* has been introduced into the work string **114** and conveyed past each of the sensors **138***a-c* such that each sensor **138***a-c* is able to detect the wellbore dart **136***a* and increase its wellbore dart "count" by one. Since the electronic circuitry associated with the third sliding sleeve assembly **130***c* is pre-programmed with a predetermined "count" of one wellbore dart, upon detecting the first wellbore dart **136***a*, the sliding sleeve **132** of the third sliding sleeve assembly **130***c* may be actuated to the open position. Upon conveying the second wellbore dart **136***b* into the work string **114**, the first and second sensors **138***a,b* are able to detect the second wellbore dart **136***b* and increase their respective wellbore dart "counts" to two. Since the electronic circuitry associated with the second sliding sleeve assembly **130***b* is pre-programmed with a predetermined "count" of two wellbore darts, upon detecting the second wellbore dart **136***b*, the sliding sleeve **132** of the second sliding sleeve assembly **130***b* may be actuated to the open position. Upon conveying a third wellbore dart (not shown) into the work string **114**, the first sensor **138***a* is able to detect the third wellbore dart and increase its wellbore dart "count" to three. Since the electronic circuitry associated with the first sliding sleeve assembly **130***a* is pre-programmed with a predetermined "count" of three wellbore darts, upon detecting the third wellbore dart, the sliding sleeve **132** of the first sliding sleeve assembly **130***a* may be actuated to the open position.

[0031] Referring now to FIGS. **2**A and **2**B, illustrated is an exemplary wellbore dart **200**, according to one or more embodiments of the present disclosure. The wellbore dart **200** may be similar to the wellbore darts **136** of FIG. **1**, and therefore may be configured to be introduced downhole to interact with the sensors **138***a-c* of the sliding sleeve assemblies **130***a-c*. FIG. **2**A depicts an isometric view of the wellbore dart **200**, and FIG. **2**B depicts a cross-sectional side view of the wellbore dart **200**. As illustrated, the wellbore dart **200** may include a generally cylindrical body **202** with a plurality of collet fingers **204** either forming part of the body **202** or extending longitudinally therefrom. The body **202** may be made of a variety of materials including, but not limited to, iron and iron alloys, steel and steel alloys, aluminum and aluminum alloys, copper and copper alloys, plastics, composite materials, and any combination thereof. In other embodiments, as described in greater detail below, all or a portion of the body **202** may be made of a degradable and/or dissolvable material, without departing from the scope of the disclosure.

[0032] In at least one embodiment, the collet fingers **204** may be flexible, axial extensions of the body **202** that are separated by elongate channels **206**. A dart profile **208** may be defined on the outer radial surface of the body **202**, such as on the collet fingers **204**. The dart profile **208** may include or otherwise provide various features, designs, and/or configurations that enable the wellbore dart **200** to mate with a corresponding sleeve mating profile (not shown) defined on a desired sliding sleeve (e.g., the sliding sleeves **132** of FIG. **1**).

[0033] The wellbore dart **200** may further include a dynamic seal **210** arranged about the exterior or outer surface of the body **202** at or near its downhole end **212**. As used herein, the term "dynamic seal" is used to indicate a seal that provides pressure and/or fluid isolation between members that have relative displacement therebetween, for example, a seal that seals against a displacing surface, or a seal carried on one member and sealing against the other member. In some embodiments, the dynamic seal **210** may be arranged within a groove **214** defined on the outer surface of the body **202**. The dynamic seal **210** may be made of a material selected from the following: elastomeric materials, non-elastomeric materials, metals, composites, rubbers, ceramics, derivatives thereof, and any combination thereof. In some embodiments, as depicted in FIG. **2**B, the dynamic seal **210** may be an O-ring or the like. In other embodiments, however, the dynamic seal **210** may be a set of v-rings or CHEVRON® packing rings, or other appropriate seal configurations (e.g., seals that are round, v-shaped, u-shaped, square, oval, t-shaped, etc.), as generally known to those skilled in the art, or any combination thereof. As described more below, the dynamic seal **210** may be configured to "dynamically" seal against a seal bore of a sliding sleeve (not shown).

[0034] The wellbore dart **200** may further include or otherwise encompass one or more detectable sensor components **216**. As used herein, the term "sensor component" refers to any mechanism, device, element, or substance that is able to interact with the sensors **138***a-c* of the sliding sleeve assemblies **130***a-c* of FIG. **1** and thereby confirm that the wellbore dart **200** has come into proximity of a given sensor **138***a-c*. For example, in some embodiments, the sensor components **216** may be magnets configured to interact with magnetic sensors **138***a-c*, as described above. In other embodiments, however, the sensor components **216** may be RFID tags (active or passive) that may be read or otherwise detected by a corresponding RFID reader associated with or otherwise encompassing the sensors **138***a-c*.

[0035] In some embodiments, the sensor components **216** may be arranged about the circumference of the wellbore dart **200**, such as being positioned on one or more of the collet fingers **204**. As best seen in FIG. **2**B, the sensor components **216** may seated or otherwise secured within corresponding recesses **218** (FIG. **2**B) defined in the collet fingers **204**. In other embodiments, however, the sensor components **216** may be secured to the outer radial surface of the collet fingers **204**. In yet other embodiments, the sensor components **216** may be positioned on the body **202** at or near the downhole end **212** or positioned on a combination of the body **202** and the collet fingers **204**. In even further embodiments, the wellbore dart **200** itself may be or otherwise encompass the sensor component **216**. In other words, in some embodiments, the wellbore dart **200** itself may be made of a material (i.e., magnets) or otherwise comprise an mechanism, device (i.e., RFID tag), element, or substance that is able to interact with the sensors **138***a-c* of the sliding sleeve assemblies **130***a-c* of FIG. **1** and thereby confirm that the wellbore dart **200** has come into proximity of the given sensor **138***a-c*.

[0036] Referring now to FIGS. **3**A and **3**B, illustrated are cross-sectional side views of an exemplary sliding sleeve assembly **300**, according to one or more embodiments. With reference to the cross-sectional angular indicator provided at the center of the page, FIG. **3**A provides a cross-sectional side view of the sliding sleeve assembly **300** (hereafter "the assembly **300**") along a vertical line, and FIG. **3**B provides a cross-sectional view of the assembly **300** along a line offset from vertical by 35°. The assembly **300** may be similar in some respects to any of the sliding sleeve assemblies **130***a-c* of FIG. **1**. As illustrated, the assembly **300** may include an elongate completion body **302** that defines an inner flow passageway **304**. The completion body **302** may have a first end **306***a* coupled to an upper sub **308***a* and a second end **306***b* coupled to a lower sub **308***b*. The assembly **300** may form part of a downhole completion, such as the completion assembly **120** of FIG. **1**. Accordingly, the upper and lower subs **308***a,b* may be used to couple the completion body **302** to corresponding upper and lower portions of the completion assembly **120** and/or the work string **114** (FIG. **1**).

[0037] In some embodiments, the completion body **302** may include an electronics sub **310** and a ported sub **312**. The electronics sub **310** may be threaded or otherwise mechanically fastened to the ported sub **312** so that the completion body **302** forms a continuous, elongate, and cylindrical structure. In other embodiments, the electronics sub **310** and the ported sub **312** may be integrally formed as a monolithic structure, without departing from the scope of the disclosure.

[0038] As best seen in FIG. **3**A, the electronics sub **310** may define or otherwise provide an electronics cavity **314** that houses electronic circuitry **316**, one or more sensors **318**, and one or more batteries **320** (three shown). As best seen in FIG. **3**B, the electronics sub **310** may further provide an actuator **322** (FIG. **3**B). The batteries **320** may provide power to operate the electronic circuitry **316**, the sensor(s) **318**, and the actuator **322**. The sensor(s) **318** may be similar to the sensors **138***a-c* of FIG. **1**, and therefore may be capable of detecting a wellbore dart (not shown) that traverses the assembly **300** via the inner flow passageway **304**.

[0039] The ported sub **312** may include a sliding sleeve **324**, one or more ports **326** (FIG. **3**A), and an actuation sleeve **328**. The sliding sleeve **324** may be similar to the sliding sleeves **132** of FIG. **1** and may be movably arranged within the ported sub **312**. The ports **326** may be similar to the ports **134** of FIG. **1** and may be defined through the ported sub **312** to enable fluid communication between the inner flow passageway **304** and an exterior of the ported sub **312**, such as a surrounding subterranean formation (e.g., the formation **108** of FIG. **1**). In FIGS. **3**A and **3**B, the sliding sleeve **324** is depicted in a closed position, where the sliding sleeve **324** generally occludes the ports **326** and thereby prevents fluid communication therethrough. As described below, however, the sliding sleeve **324** can be moved axially within the ported sub **312** to an open position, where the ports **326** are exposed and thereby facilitate fluid communication therethrough.

[0040] Referring to FIG. **4**A, illustrated is an enlarged view of the sliding sleeve **324** and the actuation sleeve **328**, as indicated by the labeled dashed line provided in FIG. **3**B. In some embodiments, the sliding sleeve **324** may be secured in the closed position with one or more shearable devices **332** (one shown). In the illustrated embodiment, the shearable devices **332** may include one or more shear pins that extend from the ported sub **312** (i.e., the completion body **302**) and into corresponding blind bores **402** defined on the outer surface of the sliding sleeve **324**. In other embodiments, the shearable device(s) **332** may be a shear ring or any other device or mechanism configured to shear or otherwise fail upon assuming a predetermined shear load applied to the sliding sleeve **324**.

[0041] The sliding sleeve **324** may further include one or more dynamic seals **404** (two shown) arranged between the outer surface of the sliding sleeve **324** and the inner surface of the ported sub **312**. The dynamic seals **404** may be configured to provide fluid isolation between the sliding sleeve **324** and the ported sub **312** and thereby prevent fluid migration through the ports **326** (FIG. **3**A) and into the inner flow passageway **304** when the sliding sleeve **324** is in the closed position. The dynamic seals **404** may be similar to the dynamic seal **210** of FIGS. **2**A-**2**B, and therefore will not be described again. In at least one embodiment, as illustrated, one or both of the dynamic seals **404***a,b* may be an O-ring.

[0042] In some embodiments, the sliding sleeve **324** may further include a lock ring **406** disposed or positioned within a lock ring groove **408** defined in the sliding sleeve **324**. The lock ring **406** may be an expandable C-ring, for example, that expands upon locating a lock ring mating groove **410** (FIGS. **3**A-**3**B). Accordingly, as the sliding sleeve **324** moves to its open position, as described below, the lock ring **406** may locate and expand into the lock ring mating groove **410**, and thereby prevent the sliding sleeve **324** from moving back to the closed position.

[0043] The sliding sleeve **324** may further provide a seal bore **412** and a sleeve mating profile **414** defined on the inner radial surface of the sliding sleeve **324**. As illustrated, the seal bore **412** may be arranged downhole from the sleeve mating profile **414**, but may equally be arranged on either end (or at an intermediate location) of the sliding sleeve **324**, without departing from the scope of the disclosure. As described below, the dart profile **208** of the wellbore dart **200** of FIGS. **2**A and **2**B may be configured to match or otherwise correspond to the sleeve mating profile **414** of the sliding sleeve **324**.

[0044] The actuation sleeve **328** may also be movably arranged within the ported sub **312** between a run-in configuration, as shown in FIGS. **3**A-**3**B and FIG. **4**A, and an actuated configuration, as shown in FIGS. **5**A-**5**C. In some embodiments, a hydraulic cavity **416** may be defined between the actuation sleeve **328** and the ported sub **312** (e.g., the completion body **302**) and sealed at each end with appropriate sealing devices **418**, such as O-rings or the like. In such embodiments, the hydraulic cavity **416** may be fluidly coupled to the electronics cavity **314** (FIG. **3**A) via one or more hydraulic conduits **420**. The hydraulic cavity **416** may be filled with a hydraulic fluid, such as silicone oil, and maintained at an increased pressure with respect to the electronics cavity **314**, which may be at ambient pressure.

[0045] The actuation sleeve **328** may have or otherwise provide an axial extension **422** that extends within at least a portion of the sliding sleeve **324**. When the actuation sleeve **328** is in its run-in configuration, as shown in FIG. **4**A, the axial extension **422** may be configured to cover or otherwise occlude the sleeve mating profile **414**. As a result, any wellbore darts passing through the inner flow passageway **304** may be unable to mate with the sleeve mating profile **414**. A wiper ring **424**, such as an O-ring or the like, may be arranged between the axial extension **422** and the inner radial surface of the sliding sleeve **324** to protect the sleeve mating profile **414** by preventing debris and sand from entering the sleeve mating profile **414**.

[0046] Referring to FIG. **4**B, illustrated is an enlarged view of the actuator **322**, as indicated by the labeled dashed line provided in FIG. **3**B. The actuator **322** may be any mechanical, electro-mechanical, hydraulic, or pneumatic actuation device capable of manipulating the configuration or position of the actuation sleeve **328**. Accordingly, the actuator **322** may be any device that can be used or otherwise triggered to move the actuation sleeve **328** from its run-in configuration (FIGS. **3**A-**3**B and FIG. **4**A) to its actuated configuration (FIGS. **5**A-**5**C). In the illustrated embodiment, the actuator **322** is an electro-hydraulic piston lock that includes a thruster **426** and a frangible member **428**. The frangible member **428** may be, for example, a burst disk or pressure barrier that prevents the pressurized hydraulic fluid within the hydraulic cavity **416** from escaping into the electronics cavity **314** (FIG. **3**A) via the hydraulic conduit **420** (FIGS. **3**B and **4**A). Accordingly, a pressure differential between the electronics and hydraulic cavities **314**, **416** is maintained across the frangible member **428** while intact.

[0047] The thruster **426** may be communicably coupled to the electronic circuitry **316** (FIG. **3**A), which, as described above, is communicably coupled to the sensor(s) **318**. When the sensor(s) **318** positively detects a wellbore dart, or a predetermined number of wellbore darts, the electronic circuitry **316** may send an actuation signal to the actuator **322**. The actuator **322** may include a chemical charge **430** that is fired upon receiving the actuation signal, and firing the chemical charge **430** may force the thruster **426** into the frangible member **428** to rupture or penetrate the frangible member **428**. Upon rupturing the frangible member **428**, the pressurized hydraulic fluid within the hydraulic cavity **416** is able to escape into the electronics cavity **314** via the hydraulic conduit **420** in seeking pressure equilibrium.

[0048] Referring again to FIG. **3**B, as the pressurized hydraulic fluid within the hydraulic cavity **416** seeks pressure equilibrium by rushing into the electronics cavity **314**, a pressure differential is generated across the actuation sleeve **328**. This generated pressure differential may result in the actuation sleeve **328** moving to its actuated configuration in the uphole direction (i.e., to the left in FIG. **3**B), as shown in

FIGS. **5**A-**5**C. Moving the actuation sleeve **328** to the actuated configuration may uncover the sleeve mating profile **414** (FIG. **4**A).

[0049] Referring again to FIG. **3**A and additionally to FIGS. **5**A-**5**C, exemplary operation of the assembly **300** is now provided. More particularly, FIGS. **3**A and **5**A-**5**C depict progressive cross-sectional views of the assembly **300** during actuation of the sliding sleeve **324** as it moves between its closed and open positions. It will be appreciated that operation of the assembly **300** may be equally descriptive of operation of any of the sliding sleeve assemblies **130***a-c* of FIG. **1**. In FIG. **3**A, the assembly **300** is depicted in a "run-in" or closed configuration, where the sliding sleeve **324** generally occludes the ports **326** defined in the completion body **302** of the assembly **300**.

[0050] In FIG. **5**A, a first wellbore dart **502***a* is depicted as having been introduced into the work string **114** (FIG. **1**) and conveyed to and through the assembly **300**. The first wellbore dart **502***a* may be similar to the wellbore dart **200** of FIGS. **2**A-**2**B, and therefore will not be described again. As illustrated, the first wellbore dart **502***a* has passed through the inner flow passageway **304** downhole from the sensor **318** and is proceeding in a downhole direction (e.g., to the right in FIG. **5**A). In some embodiments, the first wellbore dart **502***a* may be pumped to the assembly **300** from the surface **104** (FIG. **1**) using hydraulic pressure. In other embodiments, the first wellbore dart **502***a* may be dropped through the work string **114** (FIG. **1**) from the surface **104** until locating the assembly **300**. In yet other embodiments, the first wellbore dart **502***a* may be conveyed through the work string **114** by wireline, slickline, coiled tubing, etc., or it may be self-propelled until locating the assembly **300**. In even further embodiments, any combination of the foregoing techniques may be employed to convey to the first wellbore dart **502***a* to the assembly **300**.

[0051] As the first wellbore dart **502***a* passes by the sensor **318**, or comes into close proximity therewith, the sensor **318** may detect its presence and send a detection signal to the electronic circuitry **316** indicating the same. The electronic circuitry **316**, in turn, may register a "count" of the first wellbore dart **502***a* and a total running count of how many wellbore darts (including the first wellbore dart **502***a*) have bypassed the assembly **300**. When a predetermined number of wellbore darts (including the first wellbore dart **502***a*) have been counted, the electronic circuitry **316** may be programmed to actuate the assembly **300**. More particularly, when the predetermined number of wellbore darts has been detected and otherwise registered, the electronic circuitry **316** may send an actuation signal to the actuator **322** (FIGS. **3**B and **4**B), which operates to move the actuation sleeve **328** from the run-in configuration, as shown in FIG. **3**A, to the actuated configuration, as shown in FIGS. **5**A-**5**C.

[0052] In some embodiments, as mentioned above, the actuator **322** may be any mechanical, electro-mechanical, hydraulic, or pneumatic actuation device capable of displacing the actuation sleeve **328** from the run-in configuration to the actuated configuration. In other embodiments, however, as described above with reference to FIG. **4**B, the actuator **322** may be an electro-hydraulic piston lock that includes the thruster **426** and the frangible member **428** that provides a pressure barrier between the electronics cavity **314** and the hydraulic cavity **416**. Upon receiving the actuation signal, the thruster **426** penetrates the frangible member **428** and the pressurized hydraulic fluid within the hydraulic cavity **416** escapes into the electronics cavity **314** via the hydraulic conduit **420** as it seeks pressure equilibrium. As the hydraulic fluid escapes the hydraulic cavity **416**, a pressure differential is generated across the actuation sleeve **328** that urges the actuation sleeve **328** to move to the actuation configuration.

[0053] Referring to FIG. **5**A, as the actuation sleeve **328** moves to its actuation configuration, the sleeve mating profile **414** gradually becomes exposed to the inner flow passageway **304** as the axial extension **422** of the actuation sleeve **328** moves in the uphole direction. With the sleeve mating profile **414** exposed, any subsequent wellbore dart that is introduced into the inner flow passageway **304** may be able to mate with the sleeve mating profile **414**.

[0054] FIG. **5**B shows a second wellbore dart **502***b* as having been introduced into the work string **114** (FIG. **1**) and conveyed to the assembly **300**. Similar to the first wellbore dart **502***a* (FIG. **5**A), the second wellbore dart **502***b* may be similar to the wellbore dart **200** of FIGS. **2**A-**2**B and therefore will not be described again. Moreover, the first and second wellbore darts **502***a,b* may exhibit the same dart profile (e.g., the dart profile **208** of FIGS. **2**A-**2**B). Upon locating the assembly **300**, the second wellbore dart **502***b* may be configured to mate with the sliding sleeve **324**.

[0055] Referring briefly to FIG. **6**, illustrated is an enlarged view of the second wellbore dart **502***b* as it mates with the sliding sleeve **324**, as indicated in the dashed area of FIG. **5**B, according to one or more embodiments. Upon locating the assembly **300**, the downhole end **212** of the second wellbore dart **502***b* may be configured to enter the seal bore **412** provided on the inner radial surface of the sliding sleeve **324**. The dynamic seal **210** of the second wellbore dart **502***b* may be configured to engage and seal against the seal bore **412**, thereby allowing fluid pressure behind the second wellbore dart **502***b* to increase.

[0056] The dart profile **208** of the second wellbore dart **502***b* may be configured to match or otherwise correspond to the sleeve mating profile **414** of the sliding sleeve **324**. Accordingly, upon locating the assembly **300**, the dart profile **208** may mate with and otherwise engage the sleeve mating profile **414**, thereby effectively stopping the downhole progression of the second wellbore dart **502***b*. Once the dart profile **208** axially and radially aligns with the sleeve mating profile **414**, the collet fingers **204** of the second wellbore dart **502***b* may be configured to spring radially outward and thereby mate the second wellbore dart **502***b* to the sliding sleeve **324**.

[0057] Referring again to FIGS. **5**A-**5**C and, more particularly, to FIG. **5**C, with the dart profile **208** successfully mated with the sleeve mating profile **414**, an operator may increase the fluid pressure within the work string **114** (FIG. **1**) and the inner flow passageway **304** uphole from the second wellbore dart **502***b* to move the sliding sleeve **324** to the open position. The dynamic seal **210** (FIG. **6**) of the second wellbore dart **502***b* may be configured to substantially prevent the migration of high-pressure fluids past the second wellbore dart **502***b* in the downhole direction. As a result, fluid pressure uphole from the second wellbore dart **502***b* may be increased. Moreover, the one or more shearable devices **332** may be configured to maintain the sliding sleeve **324** in the closed position until assuming a predetermined shear load. As the fluid pressure increases within the inner flow passageway **304**, the increased pressure acts on the second wellbore dart **502***b*, which, in turn, acts on the sliding sleeve **324** via the mating engagement between the dart profile **208** and the sleeve mating profile **414**. Accordingly, increasing the fluid pressure within the work string **114** (FIG. **1**) may serve to increase the shear load assumed by the shearable devices **332** holding the sliding sleeve **324** in the closed position.

[0058] The fluid pressure may increase until reaching a predetermined pressure threshold, which results in the predetermined shear load being assumed by the shearable devices **332** and their subsequent failure. Once the shearable devices **332** fail, the sliding sleeve **324** may be free to axially translate within the ported sub **312** to the open position, as shown in FIG. **5**C. With the sliding sleeve **324** in the open position, the ports **326** are exposed and a well operator may then be able to perform one or more wellbore operations, such as stimulating a surrounding formation (e.g., the formation **108** of FIG. **1**).

[0059] Following stimulation operations, in at least one embodiment, a drill bit or mill (not shown) may be introduced downhole to drill out the second wellbore dart **502***b*, thereby facilitating fluid communication past the assembly **300**. While important, those skilled in the art will readily recognize that this process requires valuable time and resources. According to the present disclosure, however, the wellbore darts may be made at least partially of a dissolvable and/or degradable material to obviate the time-consuming requirement of drilling out wellbore darts in order to facilitate fluid communication therethrough. As used herein, the term "degradable material" refers to any material or substance that is capable of or otherwise configured to degrade or dissolve following the passage of a predetermined amount of time or after interaction with a particular downhole environment (e.g., temperature, pressure, downhole fluid, etc.), treatment fluid, etc.

[0060] Referring again to FIG. **2**B, for example, in some embodiments, the entire wellbore dart **200** may be made of a degradable material. In other embodiments, only a portion of the wellbore dart **200** may be made of the degradable material. For instance, in some embodiments, all or a portion of the downhole end **212** of the body **202** may be made of the degradable material. As illustrated, for example, the body **202** may further include a tip **220** that forms an integral part of the body **202** or is otherwise coupled thereto. In the illustrated embodiment, the tip **220** may be threadably coupled to the body **202**. In other embodiments, however, the tip **220** may alternatively be welded, brazed, adhered, or mechanically fastened to the body **202**, without departing from the scope of the disclosure. After stimulation operations have completed, the degradable material may be configured to dissolve or degrade, thereby leaving a full-bore inner diameter through the sliding sleeve assemblies **130***a-c* (FIG. **1**) without the need to mill or drill out.

[0061] Suitable degradable materials that may be used in accordance with the embodiments of the present disclosure include borate glasses, polyglycolic acid and polylactic acid. Polyglycolic acid and polylactic acid tend to degrade by hydrolysis as the temperature increases. Other suitable degradable materials include oil-degradable polymers, which may be either natural or synthetic polymers and include, but are not limited to, polyacrylics, polyamides, and polyolefins such as polyethylene, polypropylene, polyisobutylene, and polystyrene. Other suitable oil-degradable polymers include those that have a melting point that is such that it will dissolve at the temperature of the subterranean formation in which it is placed.

[0062] In addition to oil-degradable polymers, other degradable materials that may be used in conjunction with the embodiments of the present disclosure include, but are not limited to, degradable polymers, dehydrated salts, and/or mixtures of the two. As for degradable polymers, a polymer is considered to be "degradable" if the degradation is due to, in situ, a chemical and/or radical process such as hydrolysis, oxidation, or UV radiation. Suitable examples of degradable polymers that may be used in accordance with the embodiments of the present invention include polysaccharides such as dextran or cellulose; chitins; chitosans; proteins; aliphatic polyesters; poly(lactides); poly(glycolides); poly(ϵ-caprolactones); poly(hydroxybutyrates); poly(anhydrides); aliphatic or aromatic polycarbonates; poly(orthoesters); poly(amino acids); poly(ethylene oxides); and polyphosphazenes. Of these suitable polymers, as mentioned above, polyglycolic acid and polylactic acid may be preferred.

[0063] Polyanhydrides are another type of particularly suitable degradable polymer useful in the embodiments of the present invention. Polyanhydride hydrolysis proceeds, in situ, via free carboxylic acid chain-ends to yield carboxylic acids as final degradation products. The erosion time can be varied over a broad range of changes in the polymer backbone. Examples of suitable polyanhydrides include poly(adipic anhydride), poly(suberic anhydride), poly(sebacic anhydride), and poly(dodecanedioic anhydride). Other suitable examples include, but are not limited to, poly(maleic anhydride) and poly(benzoic anhydride).

[0064] Blends of certain degradable materials may also be suitable. One example of a suitable blend of materials is a mixture of polylactic acid and sodium borate where the mixing of an acid and base could result in a neutral solution where this is desirable. Another example would include a blend of poly(lactic acid) and boric oxide. The choice of degradable material also can depend, at least in part, on the conditions of the well, e.g., wellbore temperature. For instance, lactides have been found to be suitable for lower temperature wells, including those within the range of 60° F. to 150° F., and polylactides have been found to be suitable for well bore temperatures above this range. Also, poly(lactic acid) may be suitable for higher temperature wells. Some stereoisomers of poly(lactide) or mixtures of such stereoisomers may be suitable for even higher temperature applications. Dehydrated salts may also be suitable for higher temperature wells.

[0065] In other embodiments, the degradable material may be a galvanically corrodible metal or material configured to degrade via an electrochemical process in which the galvanically corrodible metal corrodes in the presence of an electrolyte (e.g., brine or other salt fluids in a wellbore). Suitable galvanically-corrodible metals include, but are not limited to, gold, gold-platinum alloys, silver, nickel, nickel-copper alloys, nickel-chromium alloys, copper, copper alloys (e.g., brass, bronze, etc.), chromium, tin, aluminum, iron, zinc, magnesium, and beryllium.

[0066] Embodiments disclosed herein include:

[0067] A. A sliding sleeve assembly that includes a completion body that defines an inner flow passageway and one or more ports that enable fluid communication between the inner flow passageway and an exterior of the completion body, a sliding sleeve arranged within the completion body and having a sleeve mating profile defined on an inner surface of the sliding sleeve, the sliding sleeve being movable between a closed position, where the sliding sleeve occludes the one or more ports, and an open position, where the sliding sleeve is moved to expose the one or more ports, a plurality of wellbore darts each having a body and a dart profile defined on an outer surface of the body, the dart profile of each wellbore dart being matable with the sleeve mating profile, one or more sensors positioned on the completion body to detect the plurality of wellbore darts as traversing the inner flow passageway, and an actuation sleeve arranged within the completion body and movable between a run-in configuration, where the actuation sleeve occludes the sleeve mating profile, and an actuated configuration, where the actuation sleeve is moved to expose the sleeve mating profile.

[0068] B. A method that includes introducing one or more wellbore darts into a work string extended within a wellbore, the work string providing a sliding sleeve assembly that includes a completion body defining an inner flow passageway and one or more ports that enable fluid communication between the inner flow passageway and an exterior of the completion body, wherein the sliding sleeve assembly further includes a sliding sleeve arranged within the completion body and defining a sleeve mating profile on an inner surface of the sliding sleeve, detecting the one or more wellbore darts with one or more sensors positioned on the completion body, the one or more wellbore darts each having a body and a dart profile defined on an outer surface of the body, moving an actuation sleeve arranged within the completion body from a run-in configuration to an actuated configuration when the one or more sensors detects a predetermined number of the one or more wellbore darts, exposing the sleeve mating profile as the actuation sleeve moves to the actuated configuration, locating one of the one or more wellbore darts on the sliding sleeve as the dart profile of the one of the one or more wellbore darts mates with the sleeve mating profile, increasing a fluid pressure within the work string uphole from the one of the one or more wellbore darts, and moving the sliding sleeve from a closed position, where the sliding sleeve occludes the one or more ports, to an open position, where the one or more ports are exposed.

[0069] Each of embodiments A and B may have one or more of the following additional elements in any combination: Element 1: further comprising electronic circuitry communicably coupled to the one or more sensors, and an actuator communicably coupled to the electronic circuitry, wherein, when the one or more sensors detect a predetermined number of the plurality of wellbore darts, the electronic circuitry sends an actuation signal to the actuator to move the actuation sleeve to the actuated configuration. Element 2: wherein the actuator is selected from the group consisting of a mechanical actuator, an electro-mechanical actuator, a hydraulic actuator, a pneumatic actuator, and any combination thereof. Element 3: wherein the actuator is an electro-hydraulic piston lock. Element 4: wherein each wellbore dart exhibits a known magnetic property detectable by the one or more sensors. Element 5: wherein each wellbore dart emits a radio frequency detectable by the one or more sensors. Element 6: wherein the one or more sensors are mechanical switches that are mechanically manipulated through physical contact with the plurality of wellbore darts as each wellbore dart traverses the inner flow passageway. Element 7: wherein at least a portion of the body of each wellbore dart is made from a material selected from the group consisting of iron, an iron alloy, steel, a steel alloy, aluminum, an aluminum alloy, copper, a copper alloy, plastic, a composite material, a degradable material, and any combination thereof. Element 8: wherein the degradable material is a material selected from the group consisting of a borate glass, a galvanically-corrodible metal, polyglycolic acid, polylactic acid, and any combination thereof. Element 9: wherein the actuation sleeve includes an axial extension that extends within at least a portion of the sliding sleeve to occlude the sleeve mating profile.

[0070] Element 10: wherein the sliding sleeve assembly further includes electronic circuitry communicably coupled to the one or more sensors, and wherein detecting the one or more wellbore darts with the one or more sensors comprises sending a detection signal to the electronic circuitry with the one or more sensors upon detecting each wellbore dart, and counting with the electronic circuitry how many wellbore darts have been detected by the one or more sensors based on each detection signal received. Element 11: wherein the sliding sleeve assembly further includes an actuator communicably coupled to the electronic circuitry, and wherein moving the actuation sleeve further comprises sending an actuation signal to the actuator with the electronic circuitry when the one or more sensors detects the predetermined number of the one or more wellbore darts, and actuating the actuation sleeve with the actuator to the actuated configuration upon receiving the actuation signal. Element 12: wherein detecting the one or more wellbore darts with the one or more sensors comprises detecting a known magnetic property exhibited by the one or more wellbore darts. Element 13: wherein detecting the one or more wellbore darts with the one or more sensors comprises detecting a radio frequency emitted by the one or more wellbore darts. Element 14: wherein the one or more sensors are mechanical switches, and wherein detecting the one or more wellbore darts with the one or more sensors comprises physically contacting the one or more sensors with the one or more wellbore darts as the one or more wellbore darts traverse the inner flow passageway. Element 15: wherein increasing the fluid pressure within the work string uphole from the subsequent one of the one or more wellbore darts further comprises generating a pressure differential across the one of the one or more wellbore darts and thereby transferring an axial load to the sliding sleeve and one or more shearable devices securing the sliding sleeve in the closed position, and assuming a predetermined axial load with the one or more shearable devices such that the one or more shearable devices fail and thereby allow the sliding sleeve to move to the open position. Element 16: further comprising introducing a treatment fluid into the work string, injecting the treatment fluid into a surrounding subterranean formation via the one or more ports, and releasing the fluid pressure within the work string. Element 17: wherein at least a portion of the one or more wellbore darts is made of a degradable material selected from the group consisting of a borate glass, a galvanically-corrodible metal, polyglycolic acid, polylactic acid, and any combination thereof, the method further comprising allowing the degradable material to degrade. Element 18: further comprising introducing a drill bit into the work string and advancing the drill bit to the one of the one or more wellbore darts, and drilling out the one of the one or more wellbore darts with the drill bit.

[0071] By way of example, Embodiment A may be used with Elements 1, 2, and 3; with Elements 1, 7, and 8; with Elements 1, 7, 8, and 10; with Elements 1, 4, and 5, etc.

[0072] By way of further example, Embodiment B may be used with Elements 12 and 13; with Elements 12, 13, and 14; with Elements 15 and 16; with Elements 16, 17, and 18, etc.

[0073] Therefore, the disclosed systems and methods are well adapted to attain the ends and advantages mentioned as well as those that are inherent therein. The particular embodiments disclosed above are illustrative only, as the teachings of the present disclosure may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. It is therefore evident that the particular illustrative embodiments disclosed above may be altered, combined, or modified and all such variations are considered within the scope of the present disclosure. The systems and methods illustratively disclosed herein may suitably be practiced in the absence of any element that is not specifically disclosed herein and/or any optional element disclosed herein. While compositions and methods are described in terms of "comprising," "containing," or "including" various components or steps, the compositions and methods can also "consist essentially of" or "consist of" the various components and steps. All numbers and ranges disclosed above may vary by some amount. Whenever a numerical range with a lower limit and an upper limit is disclosed, any number and any included range falling within the range is specifically disclosed. In particular, every range of values (of the form, "from about a to about b," or, equivalently, "from approximately a to b," or, equivalently, "from approximately a-b") disclosed herein is to be understood to set forth every number and range encompassed within the broader range of values. Also, the terms in the claims have their plain, ordinary meaning unless otherwise explicitly and clearly defined by the patentee. Moreover, the indefinite articles "a" or "an," as used in the claims, are defined herein to mean one or more than one of the element that it introduces.

What is claimed is:

1. A sliding sleeve assembly, comprising:

a completion body that defines an inner flow passageway and one or more ports that enable fluid communication between the inner flow passageway and an exterior of the completion body;

a sliding sleeve arranged within the completion body and having a sleeve mating profile defined on an inner surface of the sliding sleeve, the sliding sleeve being movable between a closed position, where the sliding sleeve occludes the one or more ports, and an open position, where the sliding sleeve is moved to expose the one or more ports;

a plurality of wellbore darts each having a body and a dart profile defined on an outer surface of the body, the dart profile of each wellbore dart being matable with the sleeve mating profile;

one or more sensors positioned on the completion body to detect the plurality of wellbore darts as traversing the inner flow passageway; and

an actuation sleeve arranged within the completion body and movable between a run-in configuration, where the actuation sleeve occludes the sleeve mating profile, and an actuated configuration, where the actuation sleeve is moved to expose the sleeve mating profile.

2. The sliding sleeve assembly of claim **1**, further comprising:

electronic circuitry communicably coupled to the one or more sensors; and

an actuator communicably coupled to the electronic circuitry, wherein, when the one or more sensors detect a predetermined number of the plurality of wellbore darts, the electronic circuitry sends an actuation signal to the actuator to move the actuation sleeve to the actuated configuration.

3. The sliding sleeve assembly of claim **2**, wherein the actuator is selected from the group consisting of a mechanical actuator, an electro-mechanical actuator, a hydraulic actuator, a pneumatic actuator, and any combination thereof.

4. The sliding sleeve assembly of claim **2**, wherein the actuator is an electro-hydraulic piston lock.

5. The sliding sleeve assembly of claim **1**, wherein each wellbore dart exhibits a known magnetic property detectable by the one or more sensors.

6. The sliding sleeve assembly of claim **1**, wherein each wellbore dart emits a radio frequency detectable by the one or more sensors.

7. The sliding sleeve assembly of claim **1**, wherein the one or more sensors are mechanical switches that are mechanically manipulated through physical contact with the plurality of wellbore darts as each wellbore dart traverses the inner flow passageway.

8. The sliding sleeve assembly of claim **1**, wherein at least a portion of the body of each wellbore dart is made from a material selected from the group consisting of iron, an iron alloy, steel, a steel alloy, aluminum, an aluminum alloy, copper, a copper alloy, plastic, a composite material, a degradable material, and any combination thereof.

9. The sliding sleeve assembly of claim **8**, wherein the degradable material is a material selected from the group consisting of a borate glass, a galvanically-corrodible metal, polyglycolic acid, polylactic acid, and any combination thereof.

10. The sliding sleeve assembly of claim **1**, wherein the actuation sleeve includes an axial extension that extends within at least a portion of the sliding sleeve to occlude the sleeve mating profile.

11. A method, comprising:

introducing one or more wellbore darts into a work string extended within a wellbore, the work string providing a sliding sleeve assembly that includes a completion body defining an inner flow passageway and one or more ports that enable fluid communication between the inner flow passageway and an exterior of the completion body, wherein the sliding sleeve assembly further includes a sliding sleeve arranged within the completion body and defining a sleeve mating profile on an inner surface of the sliding sleeve;

detecting the one or more wellbore darts with one or more sensors positioned on the completion body, the one or more wellbore darts each having a body and a dart profile defined on an outer surface of the body;

moving an actuation sleeve arranged within the completion body from a run-in configuration to an actuated configuration when the one or more sensors detects a predetermined number of the one or more wellbore darts;

exposing the sleeve mating profile as the actuation sleeve moves to the actuated configuration;

locating one of the one or more wellbore darts on the sliding sleeve as the dart profile of the one of the one or more wellbore darts mates with the sleeve mating profile;

increasing a fluid pressure within the work string uphole from the one of the one or more wellbore darts; and moving the sliding sleeve from a closed position, where the sliding sleeve occludes the one or more ports, to an open position, where the one or more ports are exposed.

12. The method of claim **11**, wherein the sliding sleeve assembly further includes electronic circuitry communicably coupled to the one or more sensors, and wherein detecting the one or more wellbore darts with the one or more sensors comprises:

sending a detection signal to the electronic circuitry with the one or more sensors upon detecting each wellbore dart; and

counting with the electronic circuitry how many wellbore darts have been detected by the one or more sensors based on each detection signal received.

13. The method of claim **12**, wherein the sliding sleeve assembly further includes an actuator communicably coupled to the electronic circuitry, and wherein moving the actuation sleeve further comprises:

sending an actuation signal to the actuator with the electronic circuitry when the one or more sensors detects the predetermined number of the one or more wellbore darts; and

actuating the actuation sleeve with the actuator to the actuated configuration upon receiving the actuation signal.

14. The method of claim **11**, wherein detecting the one or more wellbore darts with the one or more sensors comprises detecting a known magnetic property exhibited by the one or more wellbore darts.

15. The method of claim **11**, wherein detecting the one or more wellbore darts with the one or more sensors comprises detecting a radio frequency emitted by the one or more wellbore darts.

16. The method of claim **11**, wherein the one or more sensors are mechanical switches, and wherein detecting the one or more wellbore darts with the one or more sensors comprises physically contacting the one or more sensors with the one or more wellbore darts as the one or more wellbore darts traverse the inner flow passageway.

17. The method of claim **11**, wherein increasing the fluid pressure within the work string uphole from the subsequent one of the one or more wellbore darts further comprises:

generating a pressure differential across the one of the one or more wellbore darts and thereby transferring an axial load to the sliding sleeve and one or more shearable devices securing the sliding sleeve in the closed position; and

assuming a predetermined axial load with the one or more shearable devices such that the one or more shearable devices fail and thereby allow the sliding sleeve to move to the open position.

18. The method of claim **11**, further comprising:

introducing a treatment fluid into the work string;

injecting the treatment fluid into a surrounding subterranean formation via the one or more ports; and

releasing the fluid pressure within the work string.

19. The method of claim **18**, wherein at least a portion of the one or more wellbore darts is made of a degradable material selected from the group consisting of a borate glass, a galvanically-corrodible metal, polyglycolic acid, polylactic acid, and any combination thereof, the method further comprising allowing the degradable material to degrade.

20. The method of claim **18**, further comprising:

introducing a drill bit into the work string and advancing the drill bit to the one of the one or more wellbore darts; and

drilling out the one of the one or more wellbore darts with the drill bit.

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