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(54) Title: DOWNHOLE TOOL STRING MOVEMENT SENSOR SYSTEM

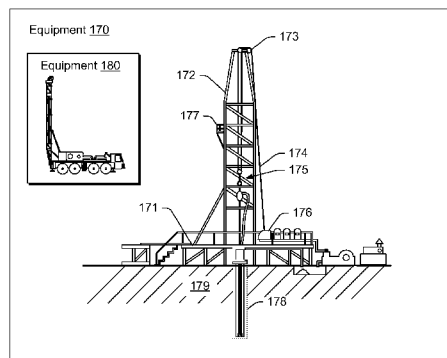
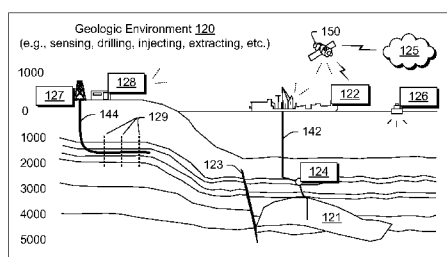


Fig. 1

(57) Abstract: A method can include acquiring motion sensor data using a motion sensor at a motion sensor location of a tool string disposed in a borehole during a field operation; transmitting the motion sensor data to transfer function circuitry of the tool string; operating the transfer function circuitry to apply a transfer function to the motion sensor data to determine one or more of lateral displacement and velocity at a location of the tool string that is a distance from the motion sensor location; and characterizing sensor data acquired by a sensor at the location using at least one of the one or more of the lateral displacement and the velocity.

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DOWNHOLE TOOL STRING MOVEMENT SENSOR SYSTEM

CROSS REFERENCE PARAGRAPH

[0001] This application claims the benefit of U.S. Provisional Application No. 63/476,292, entitled "DOWNHOLE TOOL STRING MOVEMENT SENSOR SYSTEM," filed December 20, 2022, the disclosure of which is hereby incorporated herein by reference.

BACKGROUND

[0002] Various types of operations can be performed using a downhole tool string disposed in a borehole in a subsurface geologic environment. Such a tool string can be relatively lengthy and may be somewhat flexible, for example, to handle bends in a borehole. Types of movements and motions of a tool string can differ along the length of the tool string, particularly where the tool string, or a portion thereof, is rotated.

SUMMARY

[0003] A method can include acquiring motion sensor data using a motion sensor at a motion sensor location of a tool string disposed in a borehole during a field operation; transmitting the motion sensor data to transfer function circuitry of the tool string; operating the transfer function circuitry to apply a transfer function to the motion sensor data to determine one or more of lateral displacement and velocity at a location of the tool string that is a distance from the motion sensor location; and characterizing sensor data acquired by a sensor at the location using at least one of the one or more of the lateral displacement and the velocity.

[0004] A system can include a processor; memory accessible to the processor; processor-executable instructions stored in the memory and executable by the processor to instruct the system to: acquire motion sensor data using a motion sensor at a motion sensor location of a tool string disposed in a borehole during a field operation; transmit the motion sensor data to transfer function circuitry of the tool string; operate the transfer function circuitry to apply a transfer function to the motion sensor data to determine one or more of lateral displacement and velocity at a location of the tool string that is a distance from the motion sensor location; and characterize sensor data acquired by a sensor at the location using at least one of the one or more of the lateral displacement and the velocity.

[0005] One or more computer-readable storage media can include processor-executable instructions executable to instruct a processor to: acquire motion sensor data using

a motion sensor at a motion sensor location of a tool string disposed in a borehole during a field operation; transmit the motion sensor data to transfer function circuitry of the tool string; operate the transfer function circuitry to apply a transfer function to the motion sensor data to determine one or more of lateral displacement and velocity at a location of the tool string that is a distance from the motion sensor location; and characterize sensor data acquired by a sensor at the location using at least one of the one or more of the lateral displacement and the velocity.

[0006] Various other apparatuses, systems, methods, etc., are also disclosed. 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.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] Features and advantages of the described implementations can be more readily understood by reference to the following description taken in conjunction with the accompanying drawings.

- [0008] Fig. 1 illustrates examples of equipment in a geologic environment;
- [0009] Fig. 2 illustrates an example of a system and examples of types of holes;
- [0010] Fig. 3 illustrates an example of a scenario and examples of drillstring dynamics;
- [0011] Fig. 4 illustrates an example of a tool and an example of a method;
- [0012] Fig. 5 illustrates an example of a scenario;
- [0013] Fig. 6 illustrates example plots of tool movements;
- [0014] Fig. 7 illustrates an example of a method, an example of a tool and an example of circuitry;
- [0015] Fig. 8 illustrates an example of a microprocessor and an example of circuitry;
- [0016] Fig. 9 illustrates an example of a method;
- [0017] Fig. 10 illustrates an example of a method;
- [0018] Fig. 11 illustrates example plots;
- [0019] Fig. 12 illustrates example plots;
- [0020] Fig. 13 illustrates an example of a method;
- [0021] Fig. 14 illustrates example plots;
- [0022] Fig. 15 illustrates example plots;

- [0023] Fig. 16 illustrates example plots;
[0024] Fig. 17 illustrates an example of a scenario;
[0025] Fig. 18 illustrates example plots;
[0026] Fig. 19 illustrates example plots;
[0027] Fig. 20 illustrates example plots;
[0028] Fig. 21 illustrates an example of a method and an example of a system; and
[0029] Fig. 22 illustrates examples of computing and networking equipment.

DETAILED DESCRIPTION

[0030] The following description includes embodiments of the best mode presently contemplated for practicing the described implementations. This description is not to be taken in a limiting sense, but rather is made merely for the purpose of describing the general principles of the implementations. The scope of the described implementations should be ascertained with reference to the issued claims.

[0031] As mentioned, various types of operations can be performed using a downhole tool string disposed in a borehole in a subsurface geologic environment. For example, consider a drillstring with a drill bit that can be rotated by rotation of the drillstring or a portion thereof (e.g., by a downhole motor of the drillstring). Such a drillstring can be relatively lengthy and have some amount of flexibility, for example, to handle bends in a borehole, which may be a result of directional drilling. Types of movements and motions of a drillstring can differ and vary along the length of the drillstring. For example, lateral motion along a portion close to a drill bit may differ from lateral motion of another portion that is distant from the drill bit. As such, a motion sensor positioned close to the drill bit may provide motion data that is accurate within a relatively small neighborhood of the motion sensor, which may be quite limited.

[0032] Providing a tool string with many motion sensors disposed along a length of the tool string can be impractical. Firstly, cost may be an issue and, secondly, power and/or data communication may be issues. Thus, an effort may be made to get the most out of a single motion sensor or a couple of motion sensors.

[0033] As an example, a tool string can include one or more types of sensors where sensed data may be affected by movement or motion. For example, a sensor may be disposed on a tool string in a borehole to acquire data for a formation that forms a borewall that defines the borehole where movement of the sensor from a more central position in the borehole to a more lateral position (e.g., offset) in the borehole may detrimentally affect the data. As to

motion, consider the foregoing scenario where the tool string moves from back and forth from the central position to the lateral position, which may detrimentally affect the data. If a motion sensor is collocated with the aforementioned sensor, motion data acquired by the motion sensor may be used to help characterize the data acquired by the sensor, for example, with respect to movement and/or motion. For example, consider characterizing the data as to quality or, for example, consider characterizing the data in a manner whereby the data can be adjusted based on movement and/or motion sensed by the motion sensor.

[0034] In various instances, a motion sensor cannot be practically collocated with another type of sensor. For example, consider a sensor that includes a relatively strong magnetic, a sensor that generates a substantial amount of heat, a sensor that generates strong electrical and/or magnetic fields, a sensor that emits radiation (e.g., gamma rays, X-rays, etc.). For various reasons, a sensor may be of a type that is not amenable to having a motion sensor located near or next to it. And, as explained, even if a sensor is of a type that is amenable to having a motion sensor located near or next to it, outfitting a tool string with many motion sensors can be impractical.

[0035] As an example, a method can include transforming motion sensor data from a location of a motion sensor to a location of another sensor. In such an example, the method may employ a transfer function that may be suitable for use within a neighborhood of the motion sensor. As an example, a transfer function can be generated using numerical modeling techniques, which may be applied at different scales. For example, consider a first scale (e.g., a coarse scale) that is applied to first model of a first length of a tool string and a second scale (e.g., a fine scale) that is applied to a second model of a second length of the tool string, where the second length is a fraction of the first length and describes detailed features, including geometrical details of various features (e.g., as relevant to behavior responsive to motion, etc.). In such an example, coarse scale simulation results generated through use of the first model can be utilized as conditions for generating fine scale simulation results through use of the second model where a transfer function can be generated using at least the fine scale simulation results. As an example, a second model can be discretized using a finer scale to generate smaller sized elements (e.g., volumetric elements) compared to elements of a first model.

[0036] As an example, a transfer function can be suitable for use in a downhole tool string where motion sensor data can be received as input to generate output as to movement and/or motion at another location. In such an example, the transfer function may be implemented as circuitry, which may be hardware or a combination of hardware and software

(e.g., firmware, etc.). As an example, transfer function circuitry may be implemented in a downhole tool string for real-time transformations of motion sensor data, for example, to characterize movement and/or motion at another location, which may be a sensor location of a sensor that is not a motion sensor. In such an example, data acquired by the non-motion sensor may be characterized in real-time, optionally tagged (e.g., labeled), adjusted, deleted, stored, transmitted, etc., based on how portions of the data are characterized. Such an approach can improve downhole operations using the tool string in one or more of various manners. For example, consider transmitting certain characterized data uphole to surface without transmitting other characterized data uphole to surface to expedite data availability at surface where a transmission technique may be bandwidth or otherwise limited. As another example, one or more data acquisition techniques for a sensor may be adjusted based on movement and/or motion transferred to the location of the sensor. For example, if a motion is periodic, a data acquisition technique may be synchronized or otherwise adjusted to the periodic motion. Various other techniques may be adjusted or otherwise controlled using motion sensor data that has been transformed using a transfer function. For example, consider one or more of halting acquisition of data, increasing or decreasing frequency of acquisition of data (e.g., data rate), changing one or more digital sampling parameters, changing one or more emission strengths of emitted radiation (e.g., electromagnetic, etc.), changing one or more detector sensitivities, implementing one or more filtering techniques, etc.

[0037] Below various examples of aspects of field operations and field equipment are described in which a motion sensor data may be processed using a transfer function for one or more purposes.

[0038] As explained, a tool string may be utilized to perform one or more of various operations in a field. For example, consider exploration as an initial phase in petroleum operations that includes generation of a prospect or play or both, and drilling of an exploration well or borehole. Appraisal, development and production phases may follow successful exploration.

[0039] A borehole may be referred to as a wellbore and can include an openhole portion or an uncased portion and/or may include a cased portion. A borehole may be defined by a borewall that is composed of rock that bounds the borehole. As to a well or a borehole, whether for one or more of exploration, sensing, production, injection or other operation(s), it can be planned. Such a process may be referred to generally as well planning, a process by which a path can be mapped in a geologic environment. Such a path may be

referred to as a trajectory, which can include coordinates in a three-dimensional coordinate system where a measure along the trajectory may be a measured depth (MD), a total vertical depth (TVD) or another type of measure. During drilling, wireline investigations, etc., equipment may be moved into and/or out of a well or borehole. Such operations can occur over time and may differ with respect to time (e.g., due to changed conditions). As an example, drilling can include using one or more logging tools that can perform one or more logging operations while drilling or otherwise with a drillstring (e.g., while stationary, while tripping in, tripping out, etc.). As an example, a wireline operation can include using one or more logging tools that can perform one or more logging operations. A planning process may call for performing various operations, which may be serial, parallel, serial and parallel, etc.

[0040] As an example, drilling or one or more other operations may occur responsive to measurements. For example, a logging while drilling operation may acquire measurements and adjust drilling based at least in part on such measurements. As an example, a logging operation can include moving a logging tool, stopping a logging tool, or otherwise controlling a logging tool based at least in part on measurements acquired by the logging tool or, for example, another logging tool (e.g., sensor unit, etc.).

[0041] As an example, a nuclear magnetic resonance (NMR) unit can be utilized to determine properties of objects, substances or objects and substances. In various operations, a downhole tool can include one or more NMR units that can acquire NMR measurements. Such measurements may provide for characterization of one or more objects, one or more substances, etc. Such measurements may be acquired using wireline technology, drilling technology (e.g., logging while drilling, etc.), or other downhole technology. As an example, NMR technology can be utilized in a geologic environment to characterize the geologic environment (e.g., formation characterization, fluid characterization, etc.).

[0042] As mentioned, various types of sensors may be of a type that makes it impractical for collocation of a motion sensor. For example, consider a NMR unit that may be referred to as an NMR sensor. An NMR unit can include one or more magnets that can generate a relatively strong magnetic field that may interfere with various types of motion sensing circuitry. An NMR unit may also include a radio-frequency (RF) generator that can generate RF emissions that may interfere with various types of motion sensing circuitry. Thus, it may be impractical to have a tool string where an NMR unit and a motion sensor are collocated.

[0043] As explained, NMR can be used in formation evaluation, for example, as a service available in logging while drilling (LWD) operations. An NMR unit may provide for one or more types of outputs such as, for example, lithology-independent porosity, fluid properties, and formation producibility. As explained, a sensor may be impacted by tool movement and/or motion. An NMR unit can be impacted by detrimental lateral motion, as may be induced, for example, by drillstring and/or bottom hole assembly (BHA) whirling. Such whirling can cause variations in displacements and velocities of an NMR unit, which can give rise to data quality concerns for NMR measurements. As explained, motion sensing circuitry may have to be located a distance away from an NMR unit, particularly an NMR RF antenna (e.g., receiver and/or transmitter), because of various design constraints. Therefore, the location where a motion sensor measures may not reflect the actual state of motion that occurs at an NMR antenna due to complications of drilling dynamics.

[0044] As an example, a transfer function may be utilized to transform motion sensor data to characterize movement and/or motion at a location of an NMR unit, which may be specific to a location of an NMR antenna of the NMR unit. As explained, such a transfer function may be implemented in a tool string suitable for downhole use, for example, as transfer function circuitry, which may be operatively coupled to a motion sensor and to an NMR unit. While an NMR unit is mentioned as an example, such transfer function circuitry may be utilized for one or more other purposes, which may involve one or more other types of sensors.

[0045] Fig. 1 shows an example of a geologic environment 120. In Fig. 1, the geologic environment 120 may be a sedimentary basin that includes layers (e.g., stratification) that include a reservoir 121 and that may be, for example, intersected by a fault 123 (e.g., or faults). As an example, the geologic environment 120 may be outfitted with a variety of sensors, detectors, actuators, etc. For example, equipment 122 may include communication circuitry to receive and/or to transmit information with respect to one or more networks 125. Such information may include information associated with downhole equipment 124, which may be equipment to acquire information, to assist with resource recovery, etc. For example, the downhole equipment 124 can be disposed in a bore 142 that is formed by a borewall of one or more types of rock. Other equipment 126 may be located remote from a well site and include sensing, detecting, emitting or other circuitry. Such equipment may include storage and communication circuitry to store and to communicate data, instructions, etc. As an example, one or more pieces of equipment may provide for measurement, collection, communication, storage, analysis, etc. of data (e.g., for one or more

produced resources, etc.). As an example, one or more satellites may be provided for purposes of communications, data acquisition, geolocation, etc. For example, Fig. 1 shows a satellite 150 in communication with the network 125 that may be configured for communications, noting that the satellite 150 may additionally or alternatively include circuitry for imagery (e.g., spatial, spectral, temporal, radiometric, etc.).

[0046] Fig. 1 also shows the geologic environment 120 as optionally including equipment 127 and 128 associated with a well 144 that includes a substantially horizontal portion that may intersect with one or more fractures 129. For example, consider a well in a shale formation that may include natural fractures, artificial fractures (e.g., hydraulic fractures) or a combination of natural and artificial fractures. As an example, a well may be drilled for a reservoir that is laterally extensive. In such an example, lateral variations in properties, stresses, etc. may exist where an assessment of such variations may assist with planning, operations, etc. to develop the reservoir (e.g., via fracturing, injecting, extracting, etc.). As an example, the equipment 127 and/or 128 may include components, a system, systems, etc. for fracturing, seismic sensing, analysis of seismic data, NMR logging, assessment of one or more fractures, injection, production, etc. As an example, the equipment 127 and/or 128 may provide for measurement, collection, communication, storage, analysis, etc. of data such as, for example, formation data, fluid data, production data (e.g., for one or more produced resources), etc. As an example, one or more satellites such as the satellite 150 may be provided for purposes of communications, data acquisition, etc.

[0047] Fig. 1 also shows an example of equipment 170 and an example of equipment 180. Such equipment, which may be systems of components, may be suitable for use in the geologic environment 120. While the equipment 170 and 180 are illustrated as land-based, various components may be suitable for use in an offshore system. As shown in Fig. 1, the equipment 180 can be mobile as carried by a vehicle; noting that the equipment 170 can be assembled, disassembled, transported and re-assembled, etc.

[0048] The equipment 170 includes a platform 171, a derrick 172, a crown block 173, a line 174, a traveling block assembly 175, drawworks 176 and a landing 177 (e.g., a monkeyboard). As an example, the line 174 may be controlled at least in part via the drawworks 176 such that the traveling block assembly 175 travels in a vertical direction with respect to the platform 171. For example, by drawing the line 174 in, the drawworks 176 may cause the line 174 to run through the crown block 173 and lift the traveling block assembly 175 skyward away from the platform 171; whereas, by allowing the line 174 out, the drawworks 176 may cause the line 174 to run through the crown block 173 and lower the

traveling block assembly 175 toward the platform 171. Where the traveling block assembly 175 carries pipe (e.g., casing, etc.), tracking of movement of the traveling block 175 may provide an indication as to how much pipe has been deployed. As shown, movement of the traveling block assembly 175 can provide for movement of equipment into and out of a bore 178 in a formation 179.

[0049] A derrick can be a structure used to support a crown block and a traveling block operatively coupled to the crown block at least in part via line. A derrick may be pyramidal in shape and offer a suitable strength-to-weight ratio. A derrick may be movable as a unit or in a piece by piece manner (e.g., to be assembled and disassembled).

[0050] As an example, drawworks may include a spool, brakes, a power source and assorted auxiliary devices. Drawworks may controllably reel out and reel in line. Line may be reeled over a crown block and coupled to a traveling block to gain mechanical advantage in a “block and tackle” or “pulley” fashion. Reeling out and in of line can cause a traveling block (e.g., and whatever may be hanging underneath it), to be lowered into or raised out of a bore. Reeling out of line may be powered by gravity and reeling in by a motor, an engine, etc. (e.g., an electric motor, a diesel engine, etc.).

[0051] As an example, a crown block can include a set of pulleys (e.g., sheaves) that can be located at or near a top of a derrick or a mast, over which line is threaded. A traveling block can include a set of sheaves that can be moved up and down in a derrick or a mast via line threaded in the set of sheaves of the traveling block and in the set of sheaves of a crown block. A crown block, a traveling block and a line can form a pulley system of a derrick or a mast, which may enable handling of heavy loads (e.g., drillstring, pipe, casing, liners, etc.) to be lifted out of or lowered into a bore. As an example, line may be about a centimeter to about five centimeters in diameter as, for example, steel cable. Through use of a set of sheaves, such line may carry loads heavier than the line could support as a single strand.

[0052] As an example, a derrick person may be a rig crew member that works on a platform attached to a derrick or a mast. A derrick can include a landing on which a derrick person may stand. As an example, such a landing may be about 10 meters or more above a rig floor. In an operation referred to as trip out of the hole (TOH or pull out of hole (POOH)), a derrick person may wear a safety harness that enables leaning out from the work landing (e.g., monkeyboard) to reach pipe in located at or near the center of a derrick or a mast and to throw a line around the pipe and pull it back into its storage location (e.g., fingerboards), for example, until it a time at which it may be desirable to run the pipe back

into the bore. As an example, a rig may include automated pipe-handling equipment such that the derrick person controls the machinery rather than physically handling the pipe.

[0053] As an example, a trip may refer to the act of pulling equipment from a bore (POOH) and/or placing equipment in a bore (e.g., run in hole (RIH)). As an example, equipment may include a drillstring that can be pulled out of the hole and/or place or replaced in the hole. As an example, a pipe trip may be performed where a drill bit has dulled or has otherwise ceased to drill efficiently and is to be replaced. As an example, a trip may be performed when changing section diameter, for example, upon finishing a larger bore diameter section changing equipment to drill a smaller bore diameter section.

[0054] Fig. 2 shows an example of a wellsite system 200 (e.g., at a wellsite that may be onshore or offshore). As shown, the wellsite system 200 can include a mud tank 201 for holding mud and other material (e.g., where mud can be a drilling fluid that may help to transport cuttings, etc.), a suction line 203 that serves as an inlet to a mud pump 204 for pumping mud from the mud tank 201 such that mud flows to a vibrating hose 206, a drawworks 207 for winching drill line or drill lines 212, a standpipe 208 that receives mud from the vibrating hose 206, a kelly hose 209 that receives mud from the standpipe 208, a gooseneck or goosenecks 210, a traveling block 211, a crown block 213 for carrying the traveling block 211 via the drill line or drill lines 212 (see, e.g., the crown block 173 of Fig. 1), a derrick 214 (see, e.g., the derrick 172 of Fig. 1), a kelly 218 or a top drive 240, a kelly drive bushing 219, a rotary table 220, a drill floor 221, a bell nipple 222, one or more blowout preventors (BOPs) 223, a drillstring 225, a drill bit 226, a casing head 227 and a flow pipe 228 that carries mud and other material to, for example, the mud tank 201.

[0055] In the example system of Fig. 2, a borehole 232 is formed in subsurface formations 230 by rotary drilling; noting that various example embodiments may also use directional drilling or one or more other types of drilling.

[0056] As shown in the example of Fig. 2, the drillstring 225 is suspended within the borehole 232 and has a drillstring assembly 250 that includes the drill bit 226 at its lower end. As an example, the drillstring assembly 250 may be a bottom hole assembly (BHA).

[0057] The wellsite system 200 can provide for operation of the drillstring 225 and other operations. As shown, the wellsite system 200 includes the platform 215 and the derrick 214 positioned over the borehole 232. As mentioned, the wellsite system 200 can include the rotary table 220 where the drillstring 225 passes through an opening in the rotary table 220.

[0058] As shown in the example of Fig. 2, the wellsite system 200 can include the kelly 218 and associated components, etc., or a top drive 240 and associated components. As to a kelly example, the kelly 218 may be a square or hexagonal metal/alloy bar with a hole drilled therein that serves as a mud flow path. The kelly 218 can be used to transmit rotary motion from the rotary table 220 via the kelly drive bushing 219 to the drillstring 225, while allowing the drillstring 225 to be lowered or raised during rotation. The kelly 218 can pass through the kelly drive bushing 219, which can be driven by the rotary table 220. As an example, the rotary table 220 can include a master bushing that operatively couples to the kelly drive bushing 219 such that rotation of the rotary table 220 can turn the kelly drive bushing 219 and hence the kelly 218. The kelly drive bushing 219 can include an inside profile matching an outside profile (e.g., square, hexagonal, etc.) of the kelly 218; however, with slightly larger dimensions so that the kelly 218 can freely move up and down inside the kelly drive bushing 219.

[0059] As to a top drive example, the top drive 240 can provide functions performed by a kelly and a rotary table. The top drive 240 can turn the drillstring 225. As an example, the top drive 240 can include one or more motors (e.g., electric and/or hydraulic) connected with appropriate gearing to a short section of pipe called a quill, that in turn may be screwed into a saver sub or the drillstring 225 itself. The top drive 240 can be suspended from the traveling block 211, so the rotary mechanism is free to travel up and down the derrick 214. As an example, a top drive 240 may allow for drilling to be performed with more joint stands than a kelly/rotary table approach.

[0060] In the example of Fig. 2, the mud tank 201 can hold mud, which can be one or more types of drilling fluids. As an example, a wellbore may be drilled to produce fluid, inject fluid or both (e.g., hydrocarbons, minerals, water, etc.).

[0061] In the example of Fig. 2, the drillstring 225 (e.g., including one or more downhole tools) may be composed of a series of pipes threadably connected together to form a long tube with the drill bit 226 at the lower end thereof. As the drillstring 225 is advanced into a wellbore for drilling, at some point in time prior to or coincident with drilling, the mud may be pumped by the pump 204 from the mud tank 201 (e.g., or other source) via the lines 206, 208 and 209 to a port of the kelly 218 or, for example, to a port of the top drive 240. The mud can then flow via a passage (e.g., or passages) in the drillstring 225 and out of ports located on the drill bit 226 (see, e.g., a directional arrow). As the mud exits the drillstring 225 via ports in the drill bit 226, it can then circulate upwardly through an annular region between an outer surface(s) of the drillstring 225 and surrounding wall(s) (e.g., open

borehole, casing, etc.), as indicated by directional arrows. In such a manner, the mud lubricates the drill bit 226 and carries heat energy (e.g., frictional or other energy) and formation cuttings to the surface where the mud (e.g., and cuttings) may be returned to the mud tank 201, for example, for recirculation (e.g., with processing to remove cuttings, etc.).

[0062] The mud pumped by the pump 204 into the drillstring 225 may, after exiting the drillstring 225, form a mudcake that lines the wellbore which, among other functions, may reduce friction between the drillstring 225 and surrounding wall(s) (e.g., borehole, casing, etc.). A reduction in friction may facilitate advancing or retracting the drillstring 225. During a drilling operation, the entire drillstring 225 may be pulled from a wellbore and optionally replaced, for example, with a new or sharpened drill bit, a smaller diameter drillstring, etc. As mentioned, the act of pulling a drillstring out of a hole or replacing it in a hole is referred to as tripping. A trip may be referred to as an upward trip or an outward trip or as a downward trip or an inward trip depending on trip direction.

[0063] As an example, consider a downward trip where upon arrival of the drill bit 226 of the drillstring 225 at a bottom of a wellbore, pumping of the mud commences to lubricate the drill bit 226 for purposes of drilling to enlarge the wellbore. As mentioned, the mud can be pumped by the pump 204 into a passage of the drillstring 225 and, upon filling of the passage, the mud may be used as a transmission medium to transmit energy, for example, energy that may encode information as in mud-pulse telemetry.

[0064] As an example, mud-pulse telemetry equipment may include a downhole device configured to effect changes in pressure in the mud to create an acoustic wave or waves upon which information may be modulated. In such an example, information from downhole equipment (e.g., one or more components of the drillstring 225) may be transmitted uphole to an uphole device, which may relay such information to other equipment for processing, control, etc.

[0065] As an example, telemetry equipment may operate via transmission of energy via the drillstring 225 itself. For example, consider a signal generator that imparts coded energy signals to the drillstring 225 and repeaters that may receive such energy and repeat it to further transmit the coded energy signals (e.g., information, etc.).

[0066] As an example, the drillstring 225 may be fitted with telemetry equipment 252 that includes a rotatable drive shaft, a turbine impeller mechanically coupled to the drive shaft such that the mud can cause the turbine impeller to rotate, a modulator rotor mechanically coupled to the drive shaft such that rotation of the turbine impeller causes said modulator rotor to rotate, a modulator stator mounted adjacent to or proximate to the

modulator rotor such that rotation of the modulator rotor relative to the modulator stator creates pressure pulses in the mud, and a controllable brake for selectively braking rotation of the modulator rotor to modulate pressure pulses. In such example, an alternator may be coupled to the aforementioned drive shaft where the alternator includes at least one stator winding electrically coupled to a control circuit to selectively short the at least one stator winding to electromagnetically brake the alternator and thereby selectively brake rotation of the modulator rotor to modulate the pressure pulses in the mud.

[0067] In the example of Fig. 2, an uphole control and/or data acquisition system 262 may include circuitry to sense pressure pulses generated by telemetry equipment 252 and, for example, communicate sensed pressure pulses or information derived therefrom for process, control, etc.

[0068] The assembly 250 of the illustrated example includes a logging-while-drilling (LWD) module 254, a measurement-while-drilling (MWD) module 256, an optional module 258, a rotary-steerable system (RSS) and/or motor 260, and the drill bit 226. Such components or modules may be referred to as tools where a drillstring can include a plurality of tools.

[0069] As to a RSS, it involves technology utilized for direction drilling. Directional drilling involves drilling into the Earth to form a deviated bore such that the trajectory of the bore is not vertical; rather, the trajectory deviates from vertical along one or more portions of the bore. As an example, consider a target that is located at a lateral distance from a surface location where a rig may be stationed. In such an example, drilling can commence with a vertical portion and then deviate from vertical such that the bore is aimed at the target and, eventually, reaches the target. Directional drilling may be implemented where a target may be inaccessible from a vertical location at the surface of the Earth, where material exists in the Earth that may impede drilling or otherwise be detrimental (e.g., consider a salt dome, etc.), where a formation is laterally extensive (e.g., consider a relatively thin yet laterally extensive reservoir), where multiple bores are to be drilled from a single surface bore, where a relief well is desired, etc.

[0070] One approach to directional drilling involves a mud motor; however, a mud motor can present some challenges depending on factors such as rate of penetration (ROP), transferring weight to a bit (e.g., weight on bit, WOB) due to friction, etc. A mud motor can be a positive displacement motor (PDM) that operates to drive a bit during directional drilling. A PDM operates as drilling fluid is pumped through it where the PDM converts

hydraulic power of the drilling fluid into mechanical power to cause the bit to rotate. A PDM can operate in a so-called sliding mode, when the drillstring is not rotated from the surface.

[0071] A RSS can drill directionally where there is continuous rotation from surface equipment, which can alleviate the sliding of a steerable motor (e.g., a PDM). A RSS may be deployed when drilling directionally (e.g., deviated, horizontal, or extended-reach wells). A RSS can aim to minimize interaction with a borehole wall, which can help to preserve borehole quality. A RSS can aim to exert a relatively consistent side force akin to stabilizers that rotate with the drillstring or orient the bit in the desired direction while continuously rotating at the same number of rotations per minute as the drillstring.

[0072] The LWD module 254 may be housed in a suitable type of drill collar and can contain one or a plurality of selected types of logging tools (e.g., NMR unit or units, etc.). It will also be understood that more than one LWD and/or MWD module can be employed, for example, as represented at by the module 256 of the drillstring assembly 250. Where the position of an LWD module is mentioned, as an example, it may refer to a module at the position of the LWD module 254, the module 256, etc. An LWD module can include capabilities for measuring, processing, and storing information, as well as for communicating with the surface equipment. In the illustrated example, the LWD module 254 may include a seismic measuring device, an NMR measuring device, etc.

[0073] The MWD module 256 may be housed in a suitable type of drill collar and can contain one or more devices for measuring characteristics of the drillstring 225 and the drill bit 226. As an example, the MWD tool 254 may include equipment for generating electrical power, for example, to power various components of the drillstring 225. As an example, the MWD tool 254 may include the telemetry equipment 252, for example, where the turbine impeller can generate power by flow of the mud; it being understood that other power and/or battery systems may be employed for purposes of powering various components. As an example, the MWD module 256 may include one or more of the following types of measuring devices: a weight-on-bit measuring device, a torque measuring device, a vibration measuring device, a shock measuring device, a stick slip measuring device, a direction measuring device, and an inclination measuring device.

[0074] As an example, one or more NMR measuring devices (e.g., NMR units, etc.) may be included in a drillstring (e.g., a BHA, etc.) where, for example, measurements may support one or more of geosteering, geostopping, trajectory optimization, etc. As an example, motion characterization data can be utilized for control of NMR measurements (e.g., acquisition, processing, quality assessment, etc.).

[0075] Fig. 2 also shows some examples of types of holes that may be drilled. For example, consider a slant hole 272, an S-shaped hole 274, a deep inclined hole 276 and a horizontal hole 278.

[0076] As an example, a drilling operation can include directional drilling where, for example, at least a portion of a well includes a curved axis. For example, consider a radius that defines curvature where an inclination with regard to the vertical may vary until reaching an angle between about 30 degrees and about 60 degrees or, for example, an angle to about 90 degrees or possibly greater than about 90 degrees. As an example, a trajectory and/or a drillstring may be characterized in part by a dogleg severity (DLS), which can be a two-dimensional parameter specified in degrees per 30 meters (e.g., or degrees per 100 feet).

[0077] As an example, a directional well can include several shapes where each of the shapes may aim to meet particular operational demands. As an example, a drilling process may be performed on the basis of information as and when it is relayed to a drilling engineer. As an example, inclination and/or direction may be modified based on information received during a drilling process.

[0078] As an example, deviation of a bore may be accomplished in part by use of a downhole motor and/or a turbine. As to a motor, for example, a drillstring can include a positive displacement motor (PDM).

[0079] As an example, a system may be a steerable system and include equipment to perform method such as geosteering. As mentioned, a steerable system can be or include an RSS. As an example, a steerable system can include a PDM or of a turbine on a lower part of a drillstring which, just above a drill bit, a bent sub can be mounted. As an example, above a PDM, MWD equipment that provides real time or near real time data of interest (e.g., inclination, direction, pressure, temperature, real weight on the drill bit, torque stress, etc.) and/or LWD equipment may be installed. As to the latter, LWD equipment can make it possible to send to the surface various types of data of interest, including for example, geological data (e.g., gamma ray log, resistivity, density and sonic logs, etc.).

[0080] The coupling of sensors providing information on the course of a well trajectory, in real time or near real time, with, for example, one or more logs characterizing the formations from a geological viewpoint, can allow for implementing a geosteering method. Such a method can include navigating a subsurface environment, for example, to follow a desired route to reach a desired target or targets.

[0081] As an example, a drillstring can include an azimuthal density neutron (ADN) tool for measuring density and porosity; a MWD tool for measuring inclination, azimuth and

shocks; a compensated dual resistivity (CDR) tool for measuring resistivity and gamma ray related phenomena; a combinable magnetic resonance (CMR) tool for measuring properties (e.g., relaxation properties, etc.); one or more variable gauge stabilizers; one or more bend joints; and a geosteering tool, which may include a motor and optionally equipment for measuring and/or responding to one or more of inclination, resistivity and gamma ray related phenomena.

[0082] As an example, geosteering can include intentional directional control of a wellbore based on results of downhole geological logging measurements in a manner that aims to keep a directional wellbore within a desired region, zone (e.g., a pay zone), etc. As an example, geosteering may include directing a wellbore to keep the wellbore in a particular section of a reservoir, for example, to minimize gas and/or water breakthrough and, for example, to maximize economic production from a well that includes the wellbore.

[0083] Referring again to Fig. 2, the wellsite system 200 can include one or more sensors 264 that are operatively coupled to the control and/or data acquisition system 262. As an example, a sensor or sensors may be at surface locations. As an example, a sensor or sensors may be at downhole locations. As an example, a sensor or sensors may be at one or more remote locations that are not within a distance of the order of about one hundred meters from the wellsite system 200. As an example, a sensor or sensor may be at an offset wellsite where the wellsite system 200 and the offset wellsite are in a common field (e.g., oil and/or gas field).

[0084] As an example, one or more of the sensors 264 can be provided for tracking pipe, tracking movement of at least a portion of a drillstring, etc.

[0085] As an example, the system 200 can include one or more sensors 266 that can sense and/or transmit signals to a fluid conduit such as a drilling fluid conduit (e.g., a drilling mud conduit). For example, in the system 200, the one or more sensors 266 can be operatively coupled to portions of the standpipe 208 through which mud flows. As an example, a downhole tool can generate pulses that can travel through the mud and be sensed by one or more of the one or more sensors 266 (e.g., consider mud-pulse telemetry). In such an example, the downhole tool can include associated circuitry such as, for example, encoding circuitry that can encode signals, for example, to reduce demands as to transmission. As an example, circuitry at the surface may include decoding circuitry to decode encoded information transmitted at least in part via mud-pulse telemetry. As an example, circuitry at the surface may include encoder circuitry and/or decoder circuitry and circuitry downhole may include encoder circuitry and/or decoder circuitry. As an example,

the system 200 can include a transmitter that can generate signals that can be transmitted downhole via mud (e.g., drilling fluid) as a transmission medium. As an example, data acquired by an NMR unit may be processed in a manner that can reduce data load, which can facilitate transmission. For example, consider downhole processing of NMR measurements to reduce a total number of bits to be transmitted (e.g., consider downhole data compression, downhole data analysis, etc.).

[0086] Analysis of formation information acquired by one or more tools may reveal features such as, for example, vugs, dissolution planes (e.g., dissolution along bedding planes), stress-related features, dip events, etc. As an example, a tool may acquire information that may help to characterize a reservoir, optionally a fractured reservoir where fractures may be natural and/or artificial (e.g., hydraulic fractures). A reservoir can be a porous formation where fluid can be within various pores of the porous formation and amenable to movement (e.g., to produce fluid from the reservoir). As an example, information acquired by a tool or tools may be analyzed using a framework such as the TECHLOG framework (SLB, Houston, Texas). As an example, the TECHLOG framework can be interoperable with one or more other frameworks such as, for example, the PETREL framework (SLB, Houston, Texas). As an example, a computational environment such as, for example, the DELFI environment (SLB, Houston, Texas) may be utilized, which can provide for utilization of the PETREL framework and other frameworks, optionally in interrelated manners.

[0087] Fig. 3 shows an example of a tool string 301 (e.g., a drillstring, etc.) that includes an example of a dynamic sub 302 where the tool string 301 and dynamic sub 302 are illustrated in an example scenario 310. In the example of Fig. 3, the dynamic sub 302 can include a power supply 303, one or more rotational sensors 304, one or more vibrational sensors 305 and one or more other components 306. As an example, the dynamic sub 302 may be a vibration measurement dynamic sub that can measure at least vibration of a portion of the tool string 301, for example, consider vibration associated with operation of the tool string 301 to drill into a formation. As an example, the one or more rotational sensors 304 and the one or more vibrational sensors 305 may be one or more motion sensors.

[0088] Fig. 3 also shows example plots of drillstring dynamics 330 pertaining to phenomena such as, for example, whirl. Lateral vibrations tend to be a more destructive type of vibration and can create large shocks as a BHA impacts a well bore wall (e.g., contact). Interaction between BHA and drillstring contact points may, in certain circumstances, drive a system into backward whirl. Backward whirl tends to be a more severe form of vibration,

creating high-frequency large-magnitude bending moment fluctuations that can result in high rates of component and connection fatigue. As an example, imbalance in an assembly of components can cause centrifugally induced bowing of a drillstring, which may produce forward whirl and, for example, result in one-sided wear of components.

[0089] As an example, vibrations can be characterized by type such as, for example, axial, torsional and lateral, which may occur during rotary drilling and which may be coupled. As an example, induced axial vibrations at the bit can lead to lateral vibrations in a BHA and axial and torsional vibrations may be observed at the rig floor and may be related to severe lateral vibrations downhole (e.g., near the bit). At times, severe axial vibrations near the bit may show no readily discernable visible vibrations at the surface. Under various circumstances, axial and lateral vibrations can be more violent in vertical or low-angle wells, and displacements and bending moments introduced by lateral vibrations may increase as the ratio of hole size to BHA collar size increases.

[0090] As to types of vibration models, consider a frequency domain type and a time domain type. As an example, consider a frequency domain model (e.g., a BHAV model) that may tend to be executable in a relatively rapid manner. As an example, a static model can be used to compute BHA touch points and this information can be used to compute the natural frequencies of the drillstring and BHA.

[0091] As an example, a method can include selecting one or more excitation sources (e.g., imbalance, bit blades, etc.) and can include computing a specific estimated RPMs associated with a source or sources. In such an example, an RPM can be a surface rotational speed at which the frequency of the excitation source is expected to coincide with natural frequencies of a BHA. As an example, interaction between a drillstring and a borehole wall may or may not be taken into consideration.

[0092] As to modeling of a drillstring, the IDEAS framework (SLB, Houston, Texas) may be utilized. The IDEAS framework is a 3D time-based drilling modeling system that can be used to model a drilling process as part of a scenario or scenarios. The IDEAS framework uses a beam type of model that can represent movements, motions, etc., of a drillstring. For example, consider using the IDEAS framework where, for a possible backward whirling scenario, IDEAS framework simulation can predict variation of the bending moment (T_y , T_z) at one or more different locations. A framework such as the IDEAS framework may be utilized to generate results for drillstring dynamics, which may be referred to as simulation results. For example, such a framework can simulate the behavior of a drillstring in a borehole during one or more drilling operations.

[0093] As mentioned, a multi-model approach can be utilized to generate a transfer function that can characterize movement and/or motion at one location using motion sensor data acquired at another location. Such an approach can provide for real-time state estimates of lateral motions of an NMR unit of a drillstring.

[0094] Fig. 4 shows an example of a portion of a drillstring, which may be referred to as a tool 400, that includes an NMR unit 410, a motion sensor 420 and transfer function circuitry 430. Fig. 4 also shows an example of a method 440 that can include a drilling dynamics simulation block 442, a finite element analysis (FEA) logging-while-drilling (LWD)-NMR unit tool simulation block 444, a motion at motion sensor and NMR unit block 446 (e.g., output from the simulation block 444), and a transfer function 448 that can represent a transfer function generated based at least in part on output of the FEA LWD-NMR tool simulation block 444.

[0095] As shown, the transfer function 448 may utilize one or more of Bayesian inference 432, machine learning (ML) 434, frequency spectrum analysis 436 and one or more other techniques 438. In the example of Fig. 4, the transfer function 448 may be integrated into the transfer function circuitry 430. For example, the transfer function circuitry 430 can include circuitry to perform operations according to one or more of the Bayesian inference 432, the machine learning 434, the frequency spectrum analysis 436, etc. In such an example, motion sensor data (e.g., motion sensor motion) acquired by the motion sensor 420 can be input to the transfer function 448 to generate NMR unit motion (e.g., movement and/or motion information) per the NMR unit motion block 450.

[0096] In the example of Fig. 4, a plot 449 is shown that provides an approximate representation of an example of the transfer function 448 and its operation. As shown, the transfer function 448 may act to transform motion sensor displacement and velocity at a location of a motion sensor to displacement and velocity of a location of an NMR unit, which may be accompanied by some amount of uncertainty (see, e.g., dashed line).

[0097] As to the tool 400, the NMR unit 410 can be within a neighborhood of the motion sensor 420 such that a finite element model of the tool 400 can provide reasonable simulation results that relate motion of the motion sensor 420 to motion of the NMR unit 410, particularly at a location of an NMR antenna of the NMR unit 410. In such an example, drilling dynamics simulation results (e.g., from the IDEAS framework) of a drillstring interacting with a borehole may provide boundary conditions that can be utilized in an FEA to drive the more detailed simulations of the FEA for behaviors of the tool 400 such that relatively fine scale movements of the NMR unit 410 can be characterized using motion

sensor data of the motion sensor 420. As explained, the transfer function 448 can be implemented as the transfer function circuitry 430 to perform computations downhole in a real-time manner. In such an example, the transfer function circuitry 430 may be in communication with the motion sensor 420 and the NMR unit 410 via one or more busses.

[0098] As an example, a method can include sequentially fusing results produced by one or more predictive models and available measurement data from a motion sensor in a real-time manner. While a FEA approach is mentioned, a model of a LWD-NMR tool may be a data-driven model, a physics-based model or a hybrid model that can be based on an analytical and/or numerical technique. In Fig. 4, three examples are given, including Bayesian inference 432, machine learning 434, and frequency spectrum analysis 436, for generating the transfer function 448 between motion sensor data for a motion sensor location of the motion sensor 420 and a location of the NMR unit 410.

[0099] As an example, a real-time state estimation approach can enable real-time motion risk prediction, intelligent job planning, optimized drilling, reducing TCO, and fit-for-basin verification and validation (V&V) for LWD-NMR tools. As an example, a field operation may be controlled in real-time or near real-time based on real-time state estimation. For example, a downhole controller, a surface controller or a combination downhole and surface controller can control field equipment responsive to real-time state estimation (e.g., state of a sensor, as may depend on lateral displacement, velocity, etc.). As an example, rate of penetration (ROP) of drilling may be controlled and/or limited to a maximum value in a manner that depends on how NMR data are characterized. For example, if data quality is characterized as being sub-optimal, ROP may be decreased in an effort to improve data quality, where such data may be utilized to control drilling (e.g., features discerned through analysis of NMR data). As an example, drilling parameters may be controlled in an effort to reduce lateral displacements and/or velocities of a sensor such as, for example, an NMR unit, to improve data quality, which, in turn, may improve drilling (e.g., control of drilling, etc.).

[00100] In a particular example, a workflow utilized synthetic data of a 4.75 inch (e.g., 12 cm) or larger size (e.g., 6.75 inch or 8.25 inch; 17.1 cm or 21 cm, respectively) LWD-NMR BHA that includes an NMR unit and that is instrumented with a motion sensor. These synthetic data were generated with using the IDEAS framework and an FEA package.

[00101] Fig. 5 shows an example of a scenario 500 where a model of a portion of a drillstring 520 was utilized in combination with a trajectory as shown in a trajectory plot 510. As shown, the model 520 can account for various lengths, locations, features, etc., of a drillstring. As shown, a motion sensor (MX or MotionX) was located a distance x_{MX-NMR}

from a NMR unit. The tool with the MX and NMR unit has a length denoted x_{tool} , where the ends of the tool have stabilizers (stabs) and where a stab is positioned between the MX and the NMR unit. As shown, the model 520 includes a bit where the tool is located a distance from the bit (see x_{bit}). As the model 520 interacts with an environment, as defined by the trajectory plot 510, various types of motions, movements, etc., can occur. As explained, these motions, movements, etc., may be simulated on a coarse scale that accounts for a relatively large length of a drillstring. In turn, simulation results from the coarse scale simulation can be utilized to drive a fine scale FEA simulation for a smaller portion of the drillstring (e.g., consider the tool of the model 520). As an example, a fine scale FEA simulation can utilize a simulation model (e.g., finite element model) that can model features such as, for example, one or more stabilizers (stabs), collars, subs, shells, etc., which may be parts of a drillstring.

[00102] Fig. 6 shows example plots 610 and 620 for a top view and a side view, respectively, for a portion of a drillstring that includes two sensors (squares), which may be a motion sensor and another sensor such as an NMR unit. As shown in Fig. 6, displacements (vertical axis) at a point in time can differ for the two sensors. Such displacements can be multidimensional and, for example, may be represented using a cylindrical coordinate system or a Cartesian coordinate system where a central axis, x , is a longitudinal axis from which a radial coordinate and/or y and z coordinates may be defined. As explained, a finite element model can be a detailed 3D model that, for example, can use relatively small sized elements to represent features geometrically (see, e.g., outlines in the plots 610 and 620) to account for physical aspects of a portion of a tool that includes a motion sensor and equipment at another location.

[00103] As an example, a LWD-NMR tool can include one or more NMR units. For example, consider the MAGNISPHERE tool (SLB, Houston, Texas). Such a tool can generate real-time NMR data for accurate and precise reservoir characterization, which can improve well placement for more productive hydrocarbon extraction from various wells such as, for example, extended-reach wells. NMR data can provide a better understanding of producibility in complex reservoirs. NMR data can deliver lithology-independent porosity, irreducible and producible fluid volumes, pore size distribution, and continuous permeability in various reservoirs. NMR data may be utilized to identify optimal location to perforate a section to produce desirable fluids (e.g., more oil with less water). As an example, NMR data can be utilized in reservoir modeling to generate more accurate models, which may be utilized, for example, by a reservoir or other type of simulator to generate simulation results.

[00104] Fig. 7 shows an example of a method 700 with respect to an NMR unit 770 and a sensed region 705 where the method 700 includes exposing the sensed region 705 to a static magnetic field of permanent magnet (or magnets) of the NMR unit 770, utilizing an antenna (e.g., or other transmitter) to generate an oscillating field that penetrates the sensed region 705, and utilizing the antenna (e.g., as a receiver) to receive energy released by nuclei in the sensed region 705. As shown, one or more components can be eccentric such that the NMR unit 770 can have an orientation with respect to the sensed region 705, which can be a portion of a wall of a borehole (e.g., an uncased portion of a borehole). During drilling, when at least a portion of a drillstring is rotating and the NMR unit 770 is part of the rotating portion of the drillstring, the NMR unit 770 can be rotating too. For example, the NMR unit 770 can be rotating such that it senses information for 360 degrees of a borehole (e.g., consider the sensed region 705 as being 360 degrees and surrounding the NMR unit 770). In some instances, a drillstring may be oscillated a number of degrees in one direction and a number of degrees in another direction. In such instances, an NMR unit may capture signals during rotation in either or both directions. As explained, a tool may experience lateral displacement and velocities thereof during one or more field operations, which, for example, may cause a distance between an NMR unit and a borehole wall to vary with respect to time. Such variations with respect to time can impact measurements (e.g., measurement quality, etc.).

[00105] Fig. 7 also shows an example of a tool 750, which can be part of a drillstring that may include one or more features such as a stabilizer, a pad or pads, a turbine, etc. As an example, a mud-lubricated turbine may respond to flow of mud (e.g., drilling fluid) to generate power locally, which can be utilized to power circuitry of the tool 750, including the NMR unit 770.

[00106] In Fig. 7, the NMR unit 770 is shown in an approximate side view and in an approximate cross-sectional view along a line A-A. In the cross-sectional view, the NMR unit 770 is shown to include magnets 772, an antenna 774 and circuitry 780, which can include RF emission circuitry, antenna circuitry and analog-to-digital conversion circuitry (e.g., an analog-to-digital converter (ADC)). As an example, the NMR unit 770 can include one or more passages for one or more conduits. For example, consider a power conduit, a data transmission conduit, a power and data conduit, etc. As an example, the tool 750 can include a power source or be operatively coupled to a power source, which may be a fluid driven turbine (e.g., mud turbo-generator, etc.), a surface power source, etc. As an example, a power source may be a power grid, a generator (e.g., gas, wind, fuel, etc.), a solar panel, a

battery, etc. As an example, a finite element model of a tool may include one or more elements that can represent a location of a feature or component of an NMR unit. For example, consider a finite element model that can include one or more elements that can represent an antenna of an NMR unit and its location in 3D.

[00107] As to the circuitry 780, it can include one or more processors and memory accessible to at least one of the one or more processors. For example, the circuitry 780 can include a processor that executes instructions that control energy emissions to generate an oscillating magnetic field, as may be according to a programmed pulse sequence. As an example, the circuitry 780 can include one or more switches, which may be operatively coupled to sources of energy, which can include a source to generate pulsed emissions and/or a source that is an antenna or antennas that receive signals from nuclei in a formation. For example, a switch may act to control an antenna to use the antenna for transmission of energy and then to use the antenna for reception of energy. Received energy can be directed to an analog-to-digital converter that can convert analog signals to digital data according to a selected sampling rate and/or bit depth. As an example, the digital data can be stored to memory and optionally processed by the processor (e.g., downhole) and/or transmitted to another processor, storage device, etc., which may be uphole or part of the downhole tool or another downhole tool. As an example, a processor or processors can be configured using executable instructions to perform one or more operations on data such as, for example, inversion to derive one or more values (e.g., T2 values, T1 values, etc.).

[00108] As shown in the example of Fig. 7, the circuitry 780 can include a sequencer 782, a transmitter 784, a receiver 786, and an ADC 788. The sequencer 782 can include instructions or otherwise be instructed to control the transmitter 784, which can be operatively coupled to the antenna 774 for transmission of oscillating magnetic fields. The receiver 786 can be operatively coupled to the antenna 774 for reception of echo signals where such signals can be in analog form and converted into digital echo data using the ADC 788. As shown in the example of Fig. 7, other circuitry 789 can be included, which may be operatively coupled to one or more data and/or power lines. For example, consider one or more data and/or power lines operatively coupled to an uphole (e.g., surface) unit or system. As an example, the sequencer 782 may be programmable via instructions, commands, etc., received from memory locally, from a surface unit or system, another component of a downhole string, etc. As an example, a method can include controlling emissions, which may be via RF emission circuitry. As an example, such circuitry can include the sequencer 782 and the transmitter 784 as operatively coupled to the antenna 774. As an example, a method

can include acquiring digital echo data, which may be via antenna circuitry and analog-to-digital conversion circuitry. As an example, such circuitry can include the antenna 774, the receiver 786 and the ADC 788. As an example, compression circuitry may be included to compress digital echo data (e.g., consider one or more of window summing, singular value decomposition, etc.). Data compression may reduce data density for transmission of data uphole to a surface unit or system (e.g., via the circuitry 789, etc.). As an example, the circuitry 780 can include and/or be operatively coupled to transfer function circuitry, for example, consider a bus that can receive motion sensor data that can be processed downhole via transfer function circuitry where a result thereof can be utilized to characterize data of the NMR unit and/or to control operation of an NMR unit and/or one or more other pieces of equipment.

[00109] As an example, the tool 750 can be dimensioned for receipt in a borehole with a diameter of approximately 10 cm or more. As an example, the tool 750 can be of a maximum diameter of a tool body of approximately 5 cm or more. For example, consider an outer tool body diameter of approximately 12 cm at an NMR unit (e.g., an NMR unit with a 12 cm cross-sectional dimension).

[00110] As an example, an NMR unit may be sensitive to a volume of approximately 1 cm to approximately 3 cm or more into a formation where the volume may extend a length of an antenna along a longitudinal axis of the NMR unit (e.g., 5 cm to 15 cm or more), which can be a factor in vertical resolution. As an example, an antenna can be operated as a transmitter, a receiver or both a transmitter and a receiver. As a transmitter, an antenna can transmit a sequence for an oscillating magnetic field (e.g., consider a CPMG pulse sequence, etc.). As a receiver, an antenna can receive pulse echoes from a formation, including substances in the formation such as one or more fluids.

[00111] NMR logging can face various challenges such as one or more of the three challenges described below. First, it tends to be slow due to real world physics, specifically, the prolonged time to polarize hydrogen atoms in a static magnetic field; second, it tends to have poor SNR owing to the intrinsically weak coupling between nuclear spins and the instrument detectors; and third, an NMR logging program tends to demand substantial job planning, demanding local knowledge and domain resources and resulting in a lengthy operational workflow. Methods that reduce logging time, enhance and/or characterize SNR, and streamline job design are generally desirable.

[00112] NMR can be used for reservoir characterization due to its capability of measuring the hydrogen nuclei in the fluids. As both water and hydrocarbons like oil and gas

contain hydrogen nuclei, they can be measured and quantified by NMR tools. Furthermore, NMR measurement of sample properties, such as relaxation times (T1 and T2) and diffusion coefficients enable understanding of the dynamics of these fluids, resulting in the interpretation of their physical state (e.g., free or bound), the sizes of the pores they are confined in, the viscosity and type of hydrocarbons, and the permeability, and other properties of the rock system.

[00113] NMR relaxation such as measured by T2 has been shown to be directly proportional to the surface-to-volume ratio of a porous material. Surface relaxivity is a quantity (in units of micron/second) that defines the strength of the surface relaxation phenomenon. Because of this relationship, NMR is used in petroleum exploration to obtain estimates of porosity, pore size, bound fluids, permeability, and other rock and fluid properties (e.g., “petrophysical data”). For example, it is known that a T2 distribution is closely related to the pore size distribution. Reservoir rocks often exhibit a wide range of T2s due to the difference in pore sizes, with observed T2 from several seconds down to tens of microseconds. Signals at long T2 (e.g., greater than 100 milliseconds) tend to be from large pores and such fluids may be considered producible. For shorter T2 signals (e.g., 3 milliseconds to 50 milliseconds), the fluids are often considered to be bound by capillary force of the pores. For example, fluids in sandstone rocks with T2 below 30 ms are considered bound by capillary force and tend not to produce. Thus, a cutoff value, T2 cut (e.g., T2 cut = 30 ms) can be used to calculate the bound fluid volume.

[00114] As mentioned with respect to Fig. 7, the NMR unit 770 (e.g., NMR equipment) can include the circuitry 780. Such circuitry may be “lightweight”. As an example, NMR equipment can include a microprocessor that has associated specifications. For example, consider a microprocessor with a relatively low clock rate (e.g., less than 100 MHz). As an example, NMR equipment can include memory that has associated specifications. For example, consider random access memory (RAM) with a relatively low amount of memory (e.g., less than 10 MB).

[00115] Fig. 8 shows an example of a microprocessor 800 that may be utilized in a downhole tool such as an NMR unit (e.g., NMR equipment), a motion sensor unit, transfer function circuitry, etc., along with an example of circuitry 880 that can include a plurality of microprocessors 800-1, 800-2, 800-3, 800-4, and 800-5. As shown, the circuitry 880 can include a modem processor 800-1, a controller processor 800-2, a sequencer processor 800-3, a processing and diagnostics processor 800-4, and an acquisition processor 800-5. Also shown in the example circuitry 880 of Fig. 8 are memory, an ADC, a transmitter, a receiver

and an antenna (see, e.g., the circuitry 780 of Fig. 7). As an example, the microprocessor 800 and/or the circuitry 880 can be utilized to perform one or more actions to compress acquired NMR data. For example, consider a compression technique that involves projecting NMR data to generate components and then applying an adaptive quantization technique to generate multiple, quantized data structures suitable for storage in memory and/or transmission via one or more telemetry systems.

[00116] As an example, the microprocessor 800 can include various features such as registers, cache, memory (e.g., for instructions and data), busses, a clock, address generators, interrupts, logic units, etc. As an example, the microprocessor 800 can include various features of an INTEL Corporation (Sunnyvale, California) microprocessor such as one or more of the NIOS family microprocessors (e.g., NIOS II, etc.). As an example, a microprocessor such as the microprocessor 800 may be utilized with and/or include one or more features of a device such as the CYCLONE device (Altera, San Jose, California). For example, a CYCLONE III device can include a NIOS II family microprocessor. The NIOS II family of microprocessors includes a 32-bit embedded-processor architecture designed specifically for the ALTERA family of field-programmable gate array (FPGA) integrated circuits.

[00117] A NIOS II processor can include an instruction cache, 60 MHz clock, hardware multipliers, external SRAM (for executable code and data) such as 2 MB on a modem and on a sequencer and 4 MB on a controller along with 8 MB external cache for storing FPGA image and software and a 4 GB recording cache (controller coupled). In such an example, each FPGA can possess “system on a chip” (SoC) characteristics and custom instructions to tailor functionality to the specific portion of circuitry.

[00118] As explained with respect to the example of Fig. 4, the transfer function 448 may utilize one or more of the Bayesian inference 432, the machine learning 434, the frequency spectrum analysis 436 and/or one or more other techniques. One or more of such techniques may be implemented downhole in a portion of a drillstring, for example, using circuitry that may include a microprocessor, memory, etc. Below, various examples are described for the Bayesian inference 432, the machine learning 434 and the frequency spectrum analysis 436.

[00119] Fig. 9 shows an example of a method 900 that includes an observation block 920 for receipt of observation inputs at a motion sensor at a time step k , Z_k ; a recursion block 940 for applying a recursive Bayesian filter, and an estimation block 960 for estimating output as a NMR unit, X_k .

[00120] The method 900 can use Bayesian inference for real-time estimations of NMR unit states with motion sensor data as inputs. Per the block 940, the recursive Bayesian filter can utilize one or more of different types of Bayesian filters, such as, for example, a Kalman filter and its variations (e.g., an unscented Kalman filter, an extended Kalman filter, etc.), a particle filter, etc. A Bayesian filter may be described with respect to two phases: a prediction phase and a correction phase. In the prediction phase, the state estimate from a previous time step can be utilized for producing an estimate of the state for a current time step. In the correction phase, the current a priori prediction can be combined with the current observation from a motion sensor to improve the state estimate at a location of an NMR unit, which produces an a posteriori state estimate.

[00121] The aforementioned model-data fusion approach enables a process by which real-time motion sensor data can be incorporated into a model state of a system. In such an example, a recursive estimator can operate using the estimated state from the previous time step and the current measurement to compute the estimate for the current state. In contrast to batch estimation methods, such an approach does not demand a history of observations, which can be advantageous and efficient for real time implementation as motion measurement circuitry in an LWD tool can be subject to limited storage space (e.g., limited memory) and/or computational power.

[00122] In the example of Fig. 9, k is the time step, X_k denotes the system state at time step k , Q represents process noise, R represents measurement noise, and P (not shown) can denote error covariance. Even where a Gaussian distribution assumption is the dominant assumption in an engineering application, there exist systems whose state cannot be approximated by Gaussian distributions. In this case, non-Kalman filters (e.g., a particle filter) can be utilized to more accurately estimate a system state. As an example, hidden states at an NMR unit location can be written as follows:

$$X \rightarrow \begin{bmatrix} U_{y_NMR} \\ U_{z_NMR} \\ V_{y_NMR} \\ V_{z_NMR} \end{bmatrix}$$

[00123] Above, U_{y_NMR} , U_{z_NMR} , V_{y_NMR} , and V_{z_NMR} represent lateral displacements and velocities at an NMR unit location.

[00124] Observables at the motion sensor can be written as follows:

$$Z \rightarrow \begin{bmatrix} U_{y_MX} \\ U_{z_MX} \\ V_{y_MX} \\ V_{z_MX} \end{bmatrix}$$

[00125] Above, U_{y_MX} , U_{z_MX} , V_{y_MX} , and V_{z_MX} represent lateral displacements and velocities observed at the motion sensor location.

[00126] As an example, f can be the state transition function that defines the state transition at the current time instant k and the previous one $k-1$ at an NMR unit location. For instance, the state transition function can be written based on Newton's Laws of Motion as follows:

$$f \rightarrow \begin{bmatrix} 1 & 0 & \Delta t & 0 \\ 0 & 1 & 0 & \Delta t \\ 0 & 0 & 1 & 0 \\ 0 & 0 & 0 & 1 \end{bmatrix}$$

[00127] In such an approach, h can be the measurement function that maps the hidden states to the observables:

$$h \rightarrow \begin{bmatrix} \phi U U_{yzNMR} \\ \phi V V_{yzNMR} \end{bmatrix}$$

where ϕU and ϕV are two scaling factors that denote expected transmissibility between the motion sensor and the NMR unit location (e.g., antenna location) for lateral displacements and velocities, respectively, and $\phi U = E[Tr(U_{yz})]$, $\phi V = E[Tr(V_{yz})]$ in which $E[\bullet]$ denotes the expected value of a distribution, and

$$\begin{aligned} U_{yzMX} &= \sqrt{(U_{y_MX})^2 + (U_{z_MX})^2} \\ V_{yzMX} &= \sqrt{(V_{y_MX})^2 + (V_{z_MX})^2} \\ U_{yzNMR} &= \sqrt{(U_{y_NMR})^2 + (U_{z_NMR})^2} \\ V_{yzNMR} &= \sqrt{(V_{y_NMR})^2 + (V_{z_NMR})^2} \end{aligned}$$

[00128] As an example, the probability density function (PDF) of $Tr(U_{yz})$ and the PDF of $Tr(V_{yz})$ can be determined through high-fidelity modeling.

[00129] Fig. 10 shows an example of a method 1000 along with examples of PDFs 1020 and 1040, which correspond to lateral displacement and velocity transmissibility, respectively, between a motion sensor and an NMR unit obtained by FEA with drilling dynamics loads as inputs (e.g., IDEAS framework simulation). The method 1000 includes a motion sensor measurement block 1050 for acquiring motion sensor data (e.g., motion sensor measurements) and a stochastic inference block 1060 that can utilize the motion sensor data of the block 1050 along with the PDFs 1020 and 1040 to generate NMR hidden states estimates per a NMR hidden states estimation block 1070. In such an example, estimates can be for lateral displacements and lateral velocities. As shown, estimates can be between an expectation with uncertainty (e.g., prior) and reality with noise (e.g., likelihood). As an example, stochastic inference may utilize a Markov chain technique where history has no influence as to current state.

[00130] In the example of Fig. 10, the stochastic inference block 1060 can operate according to various uncertainties. For example, consider uncertainties as to one or more of gap size between a drill collar and a chassis of an LWD tool, bumper material, motion levels, and sensor noise.

[00131] As explained, a multiscale modeling approach can be utilized where, at the BHA level (e.g., coarse scale), IDEAS framework simulations can be run to predict BHA dynamics. Then, at the tool level (e.g., fine scale), a 3D FEA model can be utilized that models collar and chassis interactions of the tool. In such an approach, the responses from the IDEAS framework simulations can be imposed as loading and boundary conditions in the tool FEA model. Such simulations can be computationally expensive. As an example, a workflow can include running a sufficient number of high-fidelity simulations offline, based on which the workflow can generate PDFs of the transmissibility in terms of velocity and displacement, for example, as shown in Fig. 10 (see PDFs 1020 and 1040). In such an example, a NMR measurement quality map may be generated that depends on the PDFs such that NMR measurement quality can be characterized responsive to sensed motion data. For example, these PDFs can be used as input to a transfer function, along with the motion sensor (MX) data. As explained, a transfer function may use a Markov chain based stochastic inference technique, which takes the prior estimate of the state in the previous time step and the motion sensor measurement in the current time step to produce the posterior estimate of

the state in the current time step. As explained, one or more uncertainties such as, for example, one or more of collar-chassis gap size, bumper material, shock level, and sensor noise, can be transitioned from the prior to the posterior through this approach. As the states in the earlier time steps are not used, this approach can be very efficient, which makes it suitable for real-time applications.

[00132] Fig. 11 shows example plots 1110 and 1120 that demonstrate real-time state estimations of lateral motions at an NMR unit using Bayesian inference and motion sensor data. Specifically, the plot 1110 shows the time series of lateral displacement U_{yz} and lateral velocity V_{yz} for ground truth at an NMR unit, Bayesian estimate at the NMR unit, and response at the motion sensor (MX or MotionX), respectively; and the plot 1120 shows the corresponding 2s-window rolling forward statistics on the MQM (motion quality map). As shown, the motion states obtained by Bayesian estimate at the NMR unit are very close to the ground truth.

[00133] As to a machine learning based approach, consider using p time steps of historical data measured by a motion sensor to infer the states of motion at an NMR unit, as expressed in the following equation:

$$X_{NMR}(k) = g(X_{MX}(k), X_{MX}(k-1), \dots, X_{MX}(k-p)),$$

where X_{NMR} , X_{MX} represent dynamic states at the NMR unit and at the motion sensor, respectively, which could include lateral displacement and/or velocity.

[00134] In the foregoing equation, g , is the function that maps the p time steps of historical data measured by the motion sensor to the states of motion in at the NMR unit at the present time instance k . Practically, g can be a linear function or a nonlinear function that can be learned with machine learning/deep learning techniques (e.g., random forest, decision tree, neural network, etc.) as a regression problem or optionally as a classification problem.

[00135] Fig. 12 shows an example plot 1200 of a comparison between the ground truth and the prediction obtained by a trained deep learning model, neural network (NN), for the lateral displacement at the NMR unit, where 100 time steps of historical data measured by the motion sensor are used (i.e., $p = 100$). As shown in the plot 1200, overall the NN prediction agrees reasonably well with true value over time series.

[00136] Fig. 13 shows an example of a frequency spectrum analysis 1310 for a transfer function that can be applied to motion sensor data acquired by a motion sensor 1350 to determine movement and motion at a location of an NMR unit 1370. In the example of Fig. 13, a method can construct a transfer function based on a frequency spectrum analysis technique. As shown, a method can include constructing and applying the transfer function where the, to build the transfer function, acceleration data at the NMR unit and motion sensor locations in lateral direction y are used. For whirling conditions, y and z directions can be coupled, where the transfer function generated is substantially the same. In the example of Fig. 13, a first FFT can be calculated to transfer the acceleration time series data into the frequency domain, then the FFT value of the NMR unit can be divided by the FFT value of motion sensor at each frequency, resulting in an FFT division curve that represents the energy transfer at different frequency levels. Next, smoothing and polynomial fitting can be performed to the resulting FFT division curve, for example, to remove or reduce noise and one or more unreasonable peaks. The resultant smoothed FFT division curve can be the transfer function.

[00137] For the application of the transfer function, inputs can be the acceleration data in the lateral direction (A_y and A_z) for the motion sensor, and then their FFTs can be calculated for preprocessing. Next, these FFTs can be multiplied by the transfer function curve, resulting in the FFTs for A_y and A_z at the NMR unit location. Finally, the FFT curves for the NMR unit location can be transferred back to the time domain using an inverse FFT, which can be used for integration into velocity and displacement.

[00138] Fig. 14 shows example plots 1410 and 1420 for constructing a transfer function. Specifically, Fig. 14 shows transfer function construction using simulation data with drilling parameters of 200 RPM and 40 klbf WOB. The FFTs of A_y for the NMR unit and the motion sensor are calculated, and their division curve is generated. The noise and peaks of the division curve are removed by smoothing, for example, using a Savitzky-Golay filter, and a 6 order polynomial fitting for different sections. After smoothing and polynomial fitting, the smoothed division curve (white dotted line) as shown in the plot 1420 is utilized as the transfer function.

[00139] Fig. 15 shows example plots 1510, 1520 and 1530 for FFT_ A_y for a motion sensor (the plot 1510), actual simulated motion at an NMR unit location (the plot 1520), and transfer function predicted motion for the NMR unit location (the plot 1530) for conditions of 200 RPM and 21 klbf WOB. A transfer function can be applied to one or more types of drilling conditions such as those of Fig. 15 (e.g., 200 RPM and 21 klbf WOB). In Fig. 15, the

plot 1530 shows the predicted NMR FFT generated from the FFT at the motion sensor location of the plot 1510 as multiplied by the transfer function.

[00140] Fig. 16 shows example plots 1610, 1620, 1630, 1640, 1650 and 1660 of comparisons of the real and the predicted acceleration, velocity, and displacement in the y direction using a transfer function. As an example, a 50Hz low pass filter can be applied to the predicted acceleration before integration to be consistent with the transfer function construction. The example plots 1610, 1620, 1630, 1640, 1650 and 1660 show acceptable agreement between the real and predicted motions.

[00141] Fig. 17 shows various diagrams and plots 1700 associated with results for a scenario involving a 4.75 inch (e.g., 12 cm) BHA run in the field. As an example, the diagrams and plots 1700 may be rendered as part of a graphical user interface (GUI), for example, as part of a validation process for generating a suitable transfer function for implementation in a tool string positioned in a downhole environment.

[00142] As to the scenario of Fig. 17, a portion of an acquired time series with recorded data available were used where the surface RPM was approximately 80 and where the surface weight on bit (WOB) was about 21 klbf. In the field run, a 4.75 inch (e.g., 12 cm) LWD-NMR tool was included in the BHA, where the distance between the motion sensor and the NMR unit is approximately 8 feet (e.g., approximately 2.4 meters). The drilling dynamics simulation (e.g., using the IDEAS framework) that was calibrated with recorded data in the field run generated simulation results that were applied in an FEA using a 3D finite element model of the LWD-NMR tool. The 3D finite element model can utilize elements that include element sizes (e.g., longitudinally) that are a fraction of the distance between the motion sensor and the NMR unit, for example, to capture aspects of motion that can be utilized to generate a transfer function.

[00143] As shown in Fig. 17, the collar's responses from the FEA model agree well with those from drilling dynamics simulation on the LWD-NMR tool. Therefore, the FEA model of the LWD-NMR tool can be used to compute the dynamic responses on the motion sensor mounted on the internal chassis considering the interaction between the collar, damper and chassis, when the collar is experiencing the environmental loads during drilling.

[00144] Fig. 18 shows example plots 1810 and 1830 that demonstrate real-time state estimations of lateral motions at a location of an NMR unit. In practice, an NMR measurement may take a few tens of seconds to acquire. In the plot 1810, 40 second time series of lateral displacement U_{yz} and lateral velocity V_{yz} for ground truth at the NMR unit

location are shown along with a Bayesian estimate at the NMR unit location and the response at the motion sensor (MotionX), respectively. In the plot 1820, corresponding 2 second window rolling forward statistics (lateral velocity mean vs. lateral displacement max) on the MQM (motion quality map) are shown. As shown in Fig. 18, the motion obtained by the Bayesian estimate at the NMR unit location is quite close to the ground truth.

[00145] Fig. 19 and Fig. 20 show example plots 1910, 1920, 2010 and 2020 for real-time estimates of states of lateral motions at an NMR unit location with measurement data obtained from a motion sensor for various drilling conditions. These plots demonstrate robustness of the transfer function approach over a wide range of drilling conditions and parameters.

[00146] The plots 1910, 1920, 2010 and 2020 show the results of real-time estimates of NMR motion based on the motion sensor's measurements for different drilling conditions in the presence of whirling on the NMR unit. It can be consistently observed that the motion measurement at the motion sensor (MotionX) can significantly underestimate the actual state at the NMR unit compared to the ground truth in the presence of whirling. However, the real-time estimates with the invented hybrid model-data fusion methods (Bayesian estimate, NMR) agree favorably well with the true state at the NMR unit for various drilling parameters, which validates the robustness of the methods for various operational conditions.

[00147] As an example, a transfer function approach utilizing transfer function circuitry in a tool string can be implemented in real-time scheme for supporting online decision making and NMR answers during drilling and can also be utilized for offline for post-job analysis applications (e.g., retrieval of information stored in memory of the tool string).

[00148] Fig. 21 shows an example of a method 2100 that includes an acquisition block 2110 for acquiring motion sensor data using a motion sensor at a motion sensor location of a tool string disposed in a borehole during a field operation; a transmission block 2120 for transmitting the motion sensor data to transfer function circuitry of the tool string; an operation block 2130 for operating the transfer function circuitry to apply a transfer function to the motion sensor data to determine one or more of lateral displacement and velocity at a location of the tool string that is a distance from the motion sensor location; and a characterization block 2140 for characterizing sensor data acquired by a sensor at the location using at least one of the one or more of the lateral displacement and the velocity.

[00149] As shown, the method 2100 can optionally include a control block for controlling drilling of the borehole based at least in part on the sensor data and/or

characterization thereof. For example, consider the sensor as being an NMR unit that can be part of a drillstring that can be utilized to drill the borehole in the formation. In such an example, drilling may be controlled based at least in part on NMR data that represent characteristics of a formation, which may be fluid characteristics, matrix characteristics, etc. As an example, the method 2100 can allow for improved drilling where NMR data can be characterized for one or more purposes (e.g., storage, transmission, processing, etc.). Such an approach may allow for a higher rate of penetration (ROP) while drilling as confidence and/or control can be improved via NMR data that can be characterized (e.g., based on motion dependent quality, etc.).

[00150] The method 2100 of Fig. 21 is shown as including various computer-readable storage medium (CRM) blocks 2111, 2121, 2131, and 2141 that can include processor-executable instructions that can instruct a computing system, which can be a control system, to perform one or more of the actions described with respect to the method 2100.

[00151] As shown in the example of Fig. 21, the system 2190 can include one or more computers 2192 that include one or more processors 2193, memory 2194 operatively coupled to at least one of the one or more processors 2193, instructions 2196 that can be, for example, stored in the memory 2194, and one or more interfaces 2195 (e.g., one or more network interfaces and/or other interfaces). As an example, the system 2190 can include one or more processor-readable media that include processor-executable instructions executable by at least one of the one or more processors 2193 to cause the system 2190 to perform actions such as, for example, one or more actions of the method 2100. As an example, the instructions 2196 can include instructions of one or more of the CRM blocks 2111, 2121, 2131, and 2141. The memory 2194 can be or include the one or more processor-readable media where the processor-executable instructions can be or include instructions. As an example, a processor-readable medium can be a computer-readable storage medium that is non-transitory that is not a signal and that is not a carrier wave.

[00152] As an example, the system 2190 can include subsystems. For example, the system 2190 can include a plurality of subsystems that may operate using equipment that is distributed where a subsystem may be referred to as being a system. For example, consider a downhole tool system and a surface system. As an example, operations of the blocks 2110, 2120, 2130 and 2140 of the method 2100 may be performed using a downhole tool system. The method 2100 may be implemented using, for example, a downhole system and/or a surface system, which may be a cloud-based or cloud-coupled system.

[00153] Various examples are given with reference to downhole tools such as a downhole tool that can be utilized for NMR logging, which can include logging while drilling (LWD). Various equipment, techniques, etc., may be utilized in one or more other types of systems.

[00154] As an example, a method can include acquiring motion sensor data using a motion sensor at a motion sensor location of a tool string disposed in a borehole during a field operation; transmitting the motion sensor data to transfer function circuitry of the tool string; operating the transfer function circuitry to apply a transfer function to the motion sensor data to determine one or more of lateral displacement and velocity at a location of the tool string that is a distance from the motion sensor location; and characterizing sensor data acquired by a sensor at the location using at least one of the one or more of the lateral displacement and the velocity.

[00155] As an example, a method may further include generating a transfer function using coarse scale simulation results of a portion of the tool string, fine scale simulation results of a shorter portion of the tool string, and a predictive technique. In such an example, the predictive technique can include one or more of stochastic inference, machine learning, and frequency spectrum analysis. As an example, coarse scale simulation results can be based on a beam model that interacts with the borehole during the field operation and/or fine scale simulation results can be based on a finite element model that utilizes the coarse scale simulation results for boundary conditions.

[00156] As an example, a distance of a motion sensor location and another location, as may be provide by a transfer function, can be greater than 0.1 meter and less than 10 meters.

[00157] As an example, a tool string can be a drillstring. In such an example, a transfer function may be applied using transfer function circuitry disposed in the drillstring to map motion at a location of a motion sensor to another location.

[00158] As an example, a method can include characterizing quality of sensor data. For example, NMR sensor data may be sensitive to lateral displacements of an NMR unit and/or velocities of a NMR unit, which may cause an antenna of the NMR unit to move with respect to a region of interest (e.g., a portion of a formation).

[00159] As an example, characterizing sensor data can include characterizing the sensor data for one or more of storage, transmission, and processing. As an example, a method can include characterizing sensor data for storage for storing a portion of the sensor data and not storing another portion of the sensor data based on one or more quality criteria.

[00160] As an example, a method can include characterizing sensor data for transmission for transmitting a portion of the sensor data and not transmitting another portion of the sensor data based on one or more quality criteria.

[00161] As an example, a method can include characterizing sensor data for processing for processing a portion of the sensor data and not processing another portion of the sensor data based on one or more quality criteria.

[00162] As an example, a method can include controlling a sensor based on characterizing sensor data, where, for example, controlling the sensor includes changing a data acquisition parameter of the sensor.

[00163] As an example, a sensor can be or include a NMR unit including a radio-frequency antenna, where a distance between the NMR unit and a motion sensor is a distance between the radio-frequency antenna and the motion sensor. In such an example, a method can include, based on the characterizing sensor data (e.g., NMR data), labeling the sensor data acquired by the NMR unit. For example, consider labeling as to one or more actions, which can include, for example, storing, transmitting, processing, etc. As explained, one or more field operations can be controlled based at least in part on characterized sensor data. For example, consider controlling ROP of drilling operations based on characterized sensor data where, for example, ROP may be reduced or limited to thereby improve quality of sensor data, which may be determined at least in part using a transfer function (e.g., downhole transfer function circuitry).

[00164] As an example, a system can include a processor; memory accessible to the processor; processor-executable instructions stored in the memory and executable by the processor to instruct the system to: acquire motion sensor data using a motion sensor at a motion sensor location of a tool string disposed in a borehole during a field operation; transmit the motion sensor data to transfer function circuitry of the tool string; operate the transfer function circuitry to apply a transfer function to the motion sensor data to determine one or more of lateral displacement and velocity at a location of the tool string that is a distance from the motion sensor location; and characterize sensor data acquired by a sensor at the location using at least one of the one or more of the lateral displacement and the velocity. In such an example, the sensor can be an NMR unit including a radio-frequency antenna (e.g., or radio-frequency antennas). As an example, a distance may be greater than 0.1 meter and less than 10 meters. As an example, a transfer function can be generated using a first, coarse model of a length of a tool string and using a second, finer model of a portion of the length of the tool string where, for example, the finer model can include discrete elements

that collectively span a distance between a motion sensor and another sensor, which may be a NMR unit.

[00165] As an example, one or more non-transitory computer-readable storage media can include processor-executable instructions executable to instruct a processor to: acquire motion sensor data using a motion sensor at a motion sensor location of a tool string disposed in a borehole during a field operation; transmit the motion sensor data to transfer function circuitry of the tool string; operate the transfer function circuitry to apply a transfer function to the motion sensor data to determine one or more of lateral displacement and velocity at a location of the tool string that is a distance from the motion sensor location; and characterize sensor data acquired by a sensor at the location using at least one of the one or more of the lateral displacement and the velocity. In such an example, the sensor can be an NMR unit including a radio-frequency antenna (e.g., or radio-frequency antennas). As an example, a distance may be greater than 0.1 meter and less than 10 meters. As an example, a transfer function can be generated using a first, coarse model of a length of a tool string and using a second, finer model of a portion of the length of the tool string where, for example, the finer model can include discrete elements that collectively span a distance between a motion sensor and another sensor, which may be a NMR unit.

[00166] As an example, one or more computer-readable storage media can include processor-executable instructions to instruct a computing system to perform one or more methods. In such an example, the one or more computer-readable storage media can be a program product (e.g., a computer program product, a computer system program product, etc.).

[00167] In some embodiments, a method or methods may be executed by a computing system. Fig. 22 shows an example of a system 2200 that can include one or more computing systems 2201-1, 2201-2, 2201-3 and 2201-4, which may be operatively coupled via one or more networks 2209, which may include wired and/or wireless networks.

[00168] As an example, a system can include an individual computer system or an arrangement of distributed computer systems. In the example of Fig. 22, the computer system 2201-1 can include one or more sets of instructions 2202, which may be or include processor-executable instructions, for example, executable to perform various tasks (e.g., receiving information, requesting information, processing information, simulation, outputting information, etc.).

[00169] As an example, a set of instructions may be executed independently, or in coordination with, one or more processors 2204, which is (or are) operatively coupled to one

or more storage media 2206 (e.g., via wire, wirelessly, etc.). As an example, one or more of the one or more processors 2204 can be operatively coupled to at least one of one or more network interface 2207. In such an example, the computer system 2201-1 can transmit and/or receive information, for example, via the one or more networks 2209 (e.g., consider one or more of the Internet, a private network, a cellular network, a satellite network, etc.). As shown, one or more other components 2208 can be included.

[00170] As an example, the computer system 2201-1 may receive from and/or transmit information to one or more other devices, which may be or include, for example, one or more of the computer systems 2201-2, etc. A device may be located in a physical location that differs from that of the computer system 2201-1. As an example, a location may be, for example, a processing facility location, a data center location (e.g., server farm, etc.), a rig location, a wellsite location, a downhole location, etc.

[00171] As an example, a processor may be or include a microprocessor, microcontroller, processor component or subsystem, programmable integrated circuit, programmable gate array, or another control or computing device.

[00172] As an example, the storage media 2206 may be implemented as one or more computer-readable or machine-readable storage media. As an example, storage may be distributed within and/or across multiple internal and/or external enclosures of a computing system and/or additional computing systems.

[00173] As an example, a storage medium or storage media may include one or more different forms of memory including semiconductor memory devices such as dynamic or static random access memories (DRAMs or SRAMs), erasable and programmable read-only memories (EPROMs), electrically erasable and programmable read-only memories (EEPROMs) and flash memories, magnetic disks such as fixed, floppy and removable disks, other magnetic media including tape, optical media such as compact disks (CDs) or digital video disks (DVDs), BLUERAY disks, or other types of optical storage, or other types of storage devices.

[00174] As an example, a storage medium or media may be located in a machine running machine-readable instructions, or located at a remote site from which machine-readable instructions may be downloaded over a network for execution.

[00175] As an example, various components of a system such as, for example, a computer system, may be implemented in hardware, software, or a combination of both hardware and software (e.g., including firmware), including one or more signal processing and/or application specific integrated circuits.

[00176] As an example, a system may include a processing apparatus that may be or include a general purpose processors or application specific chips (e.g., or chipsets), such as ASICs, FPGAs, PLDs, or other appropriate devices.

[00177] As an example, a device may be a mobile device that includes one or more network interfaces for communication of information. For example, a mobile device may include a wireless network interface (e.g., operable via IEEE 802.11, ETSI GSM, BLUETOOTH, satellite, etc.). As an example, a mobile device may include components such as a main processor, memory, a display, display graphics circuitry (e.g., optionally including touch and gesture circuitry), a SIM slot, audio/video circuitry, motion processing circuitry (e.g., accelerometer, gyroscope), wireless LAN circuitry, smart card circuitry, transmitter circuitry, GPS circuitry, and a battery. As an example, a mobile device may be configured as a cell phone, a tablet, etc. As an example, a method may be implemented (e.g., wholly or in part) using a mobile device. As an example, a system may include one or more mobile devices.

[00178] As an example, a system may be a distributed environment, for example, a so-called “cloud” environment where various devices, components, etc. interact for purposes of data storage, communications, computing, etc. As an example, a device or a system may include one or more components for communication of information via one or more of the Internet (e.g., where communication occurs via one or more Internet protocols), a cellular network, a satellite network, etc. As an example, a method may be implemented in a distributed environment (e.g., wholly or in part as a cloud-based service).

[00179] As an example, information may be input from a display (e.g., consider a touchscreen), output to a display or both. As an example, information may be output to a projector, a laser device, a printer, etc. such that the information may be viewed. As an example, information may be output stereographically or holographically. As to a printer, consider a 2D or a 3D printer. As an example, a 3D printer may include one or more substances that can be output to construct a 3D object. For example, data may be provided to a 3D printer to construct a 3D representation of a subterranean formation. As an example, layers may be constructed in 3D (e.g., horizons, etc.), geobodies constructed in 3D, etc. As an example, holes, fractures, etc., may be constructed in 3D (e.g., as positive structures, as negative structures, etc.).

[00180] Although only a few examples have been described in detail above, those skilled in the art will readily appreciate that many modifications are possible in the examples. Accordingly, all such modifications are intended to be included within the scope of this

disclosure as defined in the following claims. In the claims, means-plus-function clauses are intended to cover the structures described herein as performing the recited function and not only structural equivalents, but also equivalent structures. Thus, although a nail and a screw may not be structural equivalents in that a nail employs a cylindrical surface to secure wooden parts together, whereas a screw employs a helical surface, in the environment of fastening wooden parts, a nail and a screw may be equivalent structures.

CLAIMS

What is claimed is:

1. A method comprising:

acquiring motion sensor data using a motion sensor at a motion sensor location of a tool string disposed in a borehole during a field operation;

transmitting the motion sensor data to transfer function circuitry of the tool string;

operating the transfer function circuitry to apply a transfer function to the motion sensor data to determine one or more of lateral displacement and velocity at a location of the tool string that is a distance from the motion sensor location; and

characterizing sensor data acquired by a sensor at the location using at least one of the one or more of the lateral displacement and the velocity.

2. The method of claim 1, further comprising generating the transfer function using coarse scale simulation results of a portion of the tool string, fine scale simulation results of a shorter portion of the tool string, and a predictive technique.

3. The method of claim 2, wherein the predictive technique comprises one or more of stochastic inference, machine learning, and frequency spectrum analysis.

4. The method of claim 2, wherein the coarse scale simulation results are based on a beam model that interacts with the borehole during the field operation.

5. The method of claim 2, wherein the fine scale simulation results are based on a finite element model that utilizes the coarse scale simulation results for boundary conditions.

6. The method of claim 1, wherein the distance is greater than 0.1 meter and less than 10 meters.

7. The method of claim 1, wherein the tool string is a drillstring.

8. The method of claim 1, wherein characterizing the sensor data comprising characterizing quality of the sensor data.

9. The method of claim 1, wherein characterizing the sensor data comprises characterizing the sensor data for one or more of storage, transmission, and processing.
10. The method of claim 9, further comprising characterizing the sensor data for storage for storing a portion of the sensor data and not storing another portion of the sensor data based on one or more quality criteria.
11. The method of claim 9, further comprising characterizing the sensor data for transmission for transmitting a portion of the sensor data and not transmitting another portion of the sensor data based on one or more quality criteria.
12. The method of claim 9, further comprising characterizing the sensor data for processing for processing a portion of the sensor data and not processing another portion of the sensor data based on one or more quality criteria.
13. The method of claim 1, further comprising controlling the sensor based on the characterizing, wherein controlling the sensor comprises changing a data acquisition parameter of the sensor.
14. The method of claim 1, wherein the sensor comprises a NMR unit comprising a radio-frequency antenna, wherein the distance is a distance between the radio-frequency antenna and the motion sensor, and further comprising, based on the characterizing, labeling the sensor data acquired by the NMR unit.
15. A system comprising:
- a processor;
 - memory accessible to the processor;
 - processor-executable instructions stored in the memory and executable by the processor to instruct the system to:
 - acquire motion sensor data using a motion sensor at a motion sensor location of a tool string disposed in a borehole during a field operation;
 - transmit the motion sensor data to transfer function circuitry of the tool string;

operate the transfer function circuitry to apply a transfer function to the motion sensor data to determine one or more of lateral displacement and velocity at a location of the tool string that is a distance from the motion sensor location; and

characterize sensor data acquired by a sensor at the location using at least one of the one or more of the lateral displacement and the velocity.

16. The system of claim 15, wherein the sensor is an NMR unit comprising a radio-frequency antenna.

17. The system of claim 15, wherein the distance is greater than 0.1 meter and less than 10 meters.

18. One or more non-transitory computer-readable storage media comprising processor-executable instructions executable to instruct a processor to:

acquire motion sensor data using a motion sensor at a motion sensor location of a tool string disposed in a borehole during a field operation;

transmit the motion sensor data to transfer function circuitry of the tool string;

operate the transfer function circuitry to apply a transfer function to the motion sensor data to determine one or more of lateral displacement and velocity at a location of the tool string that is a distance from the motion sensor location; and

characterize sensor data acquired by a sensor at the location using at least one of the one or more of the lateral displacement and the velocity.

19. The one or more computer-readable storage media of claim 18, wherein the sensor is an NMR unit comprising a radio-frequency antenna.

20. The one or more computer-readable storage media of claim 18, wherein the distance is greater than 0.1 meter and less than 10 meters.

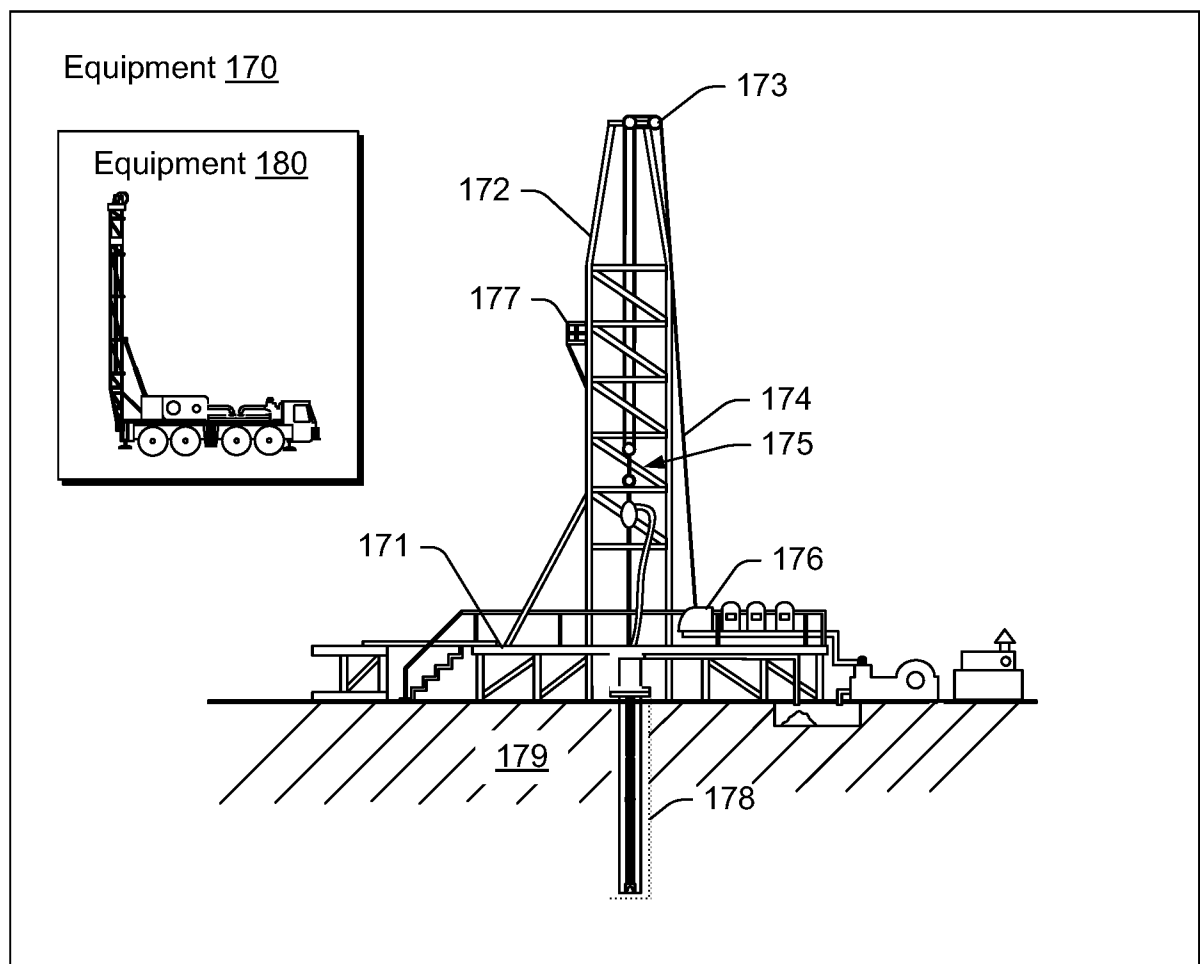
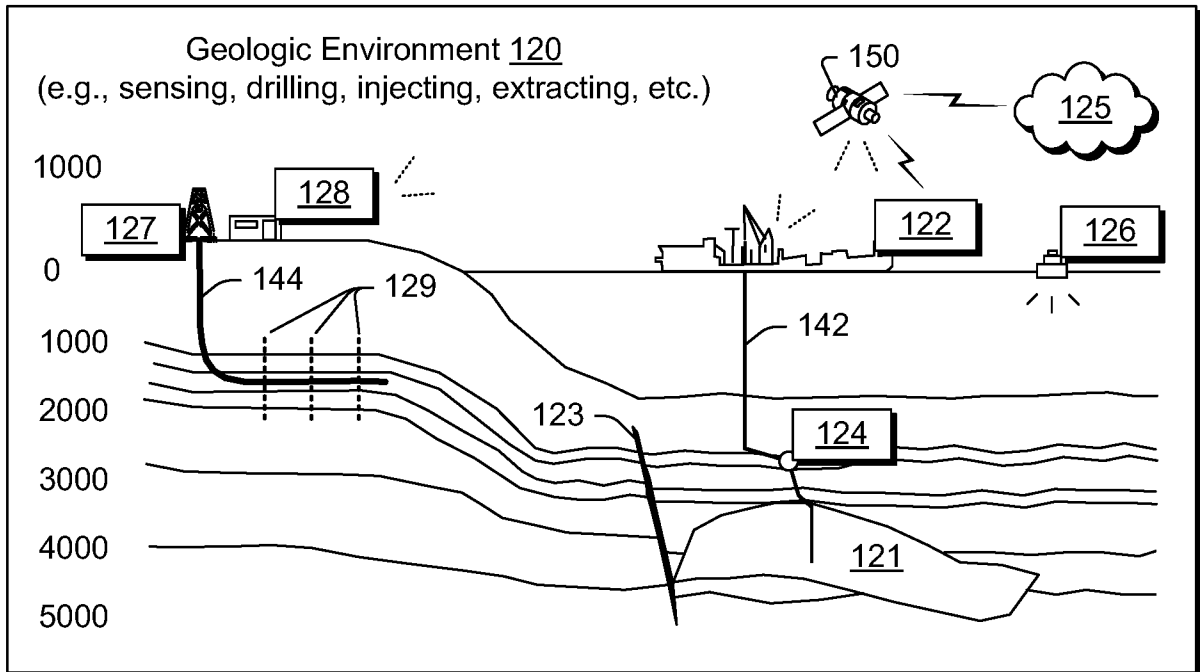
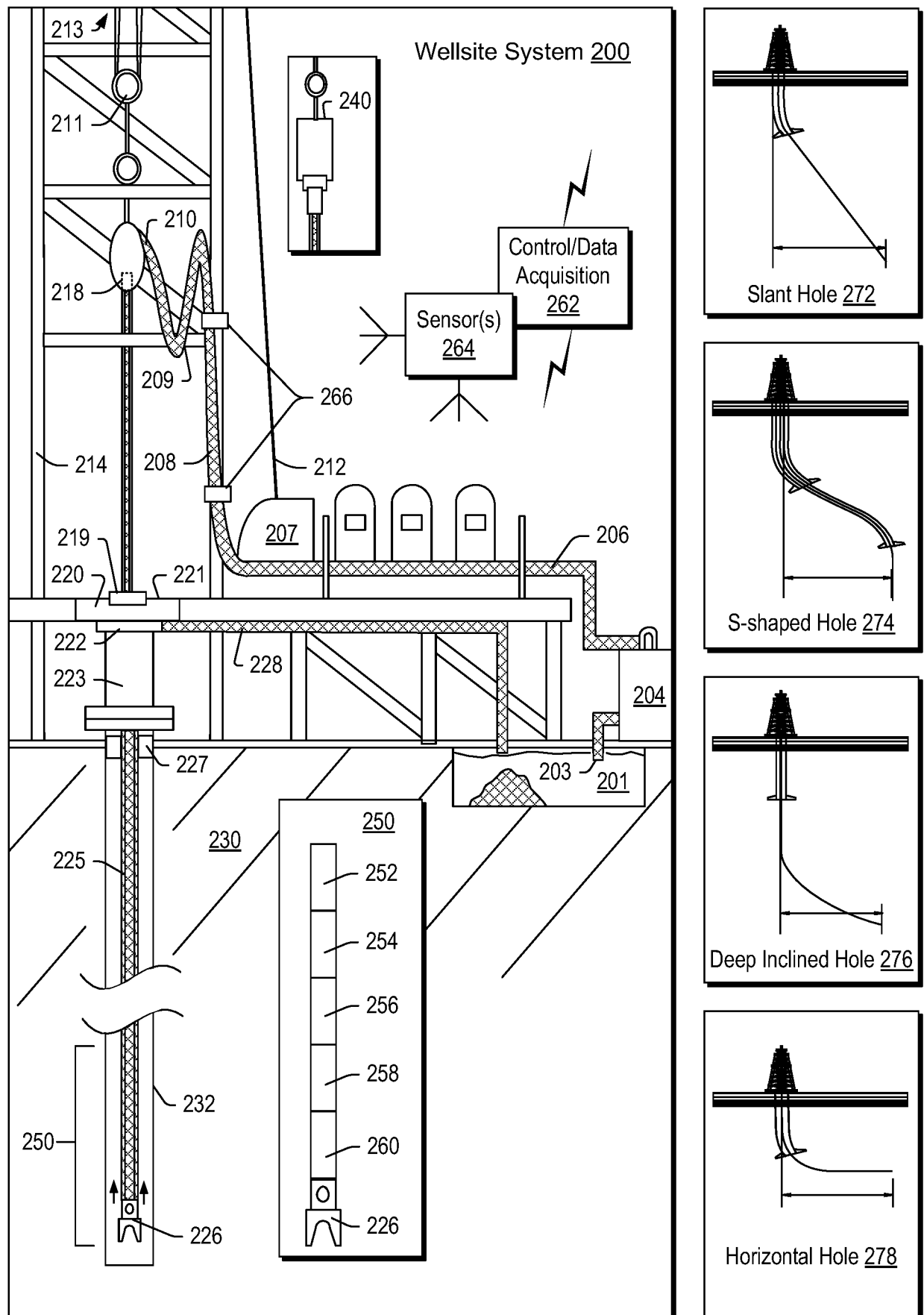
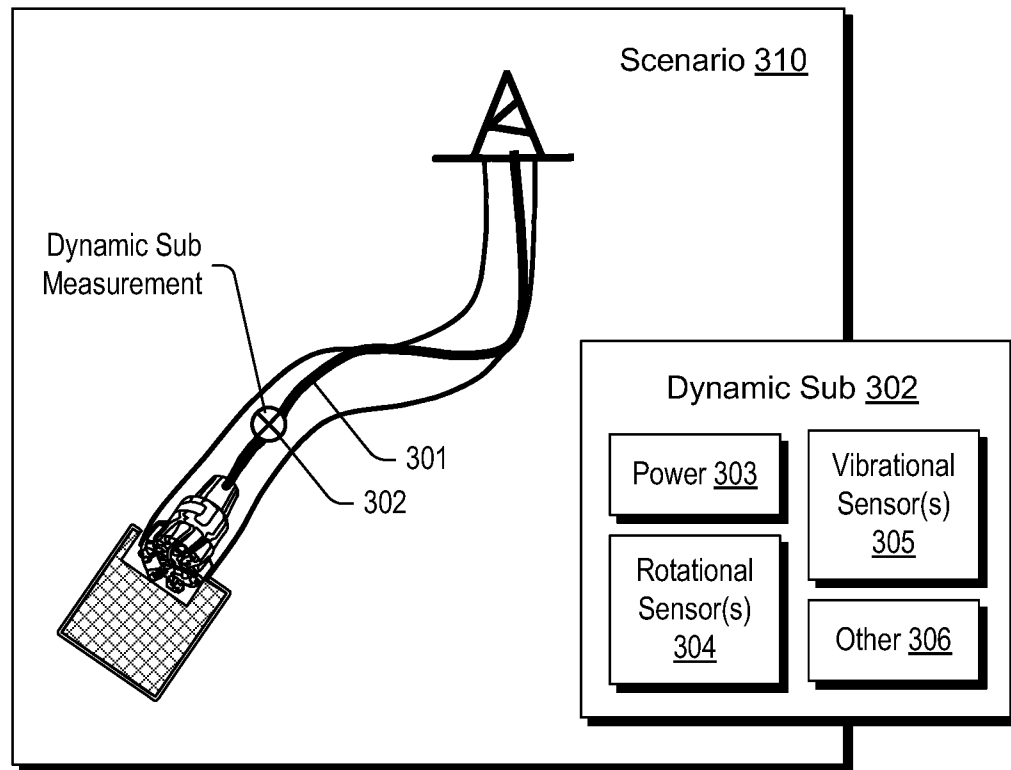


Fig. 1





Drillstring Dynamics 330

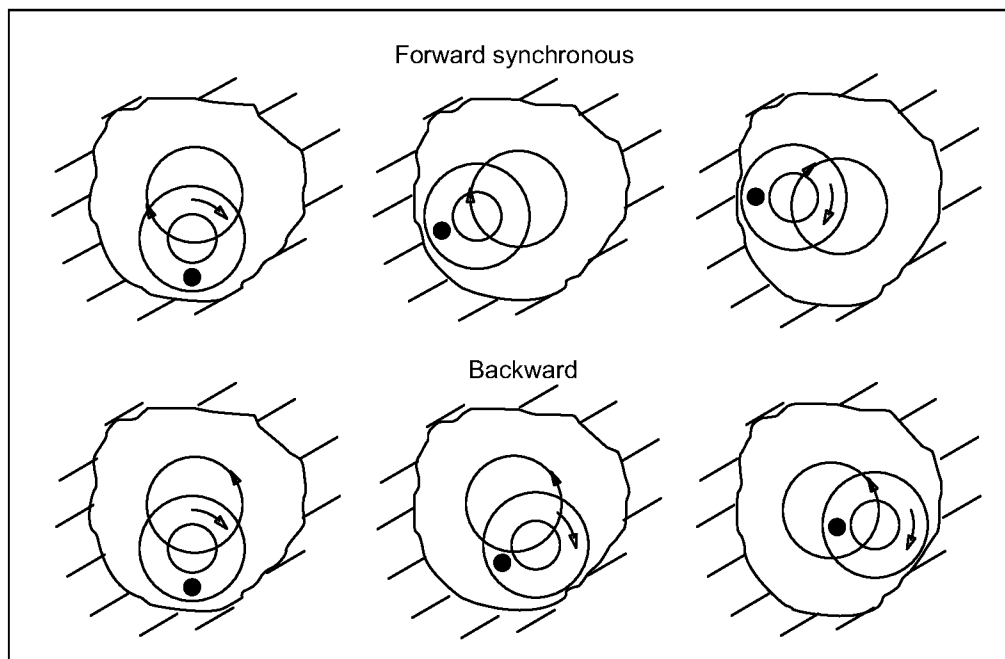


Fig. 3

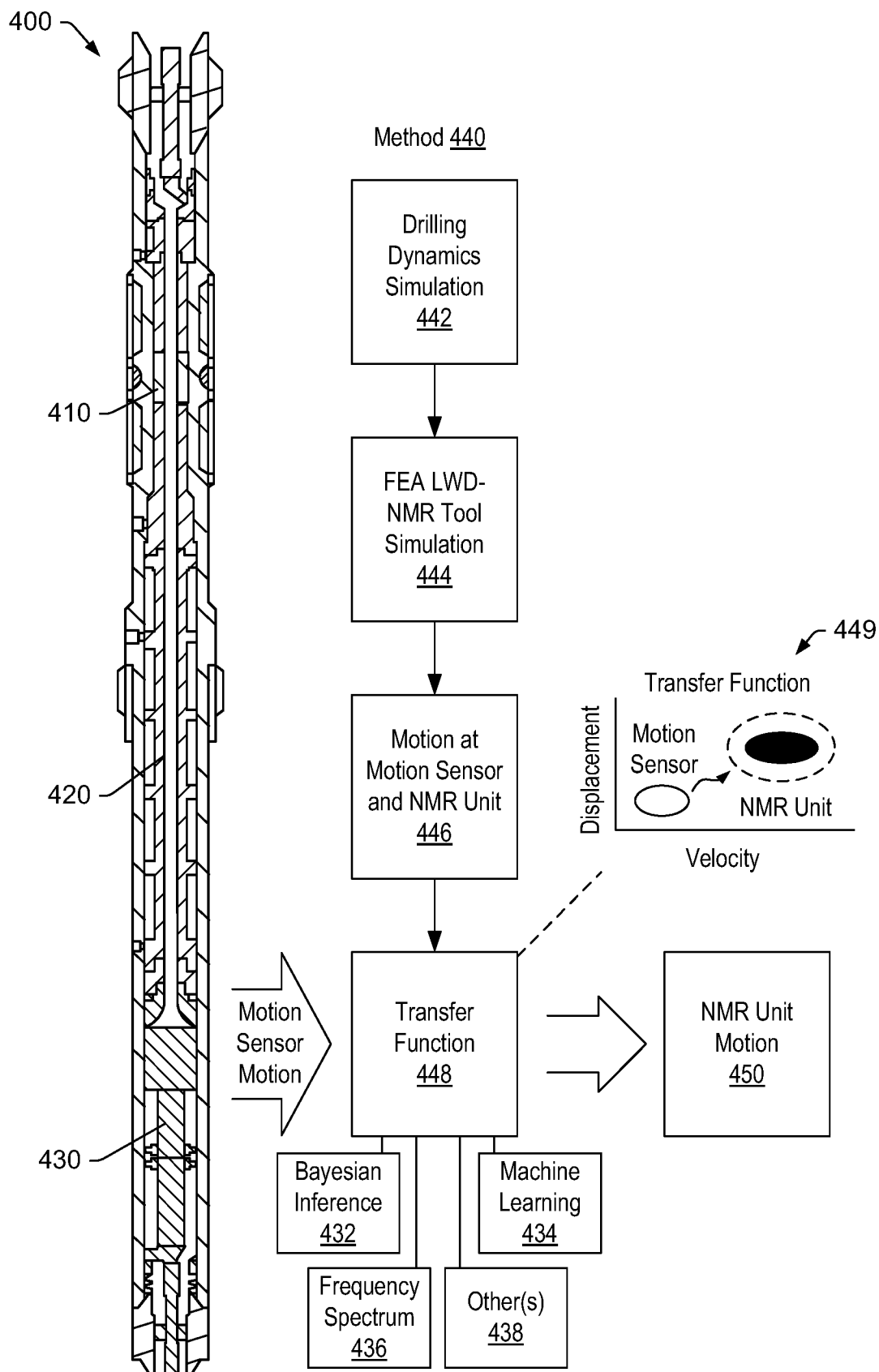


Fig. 4

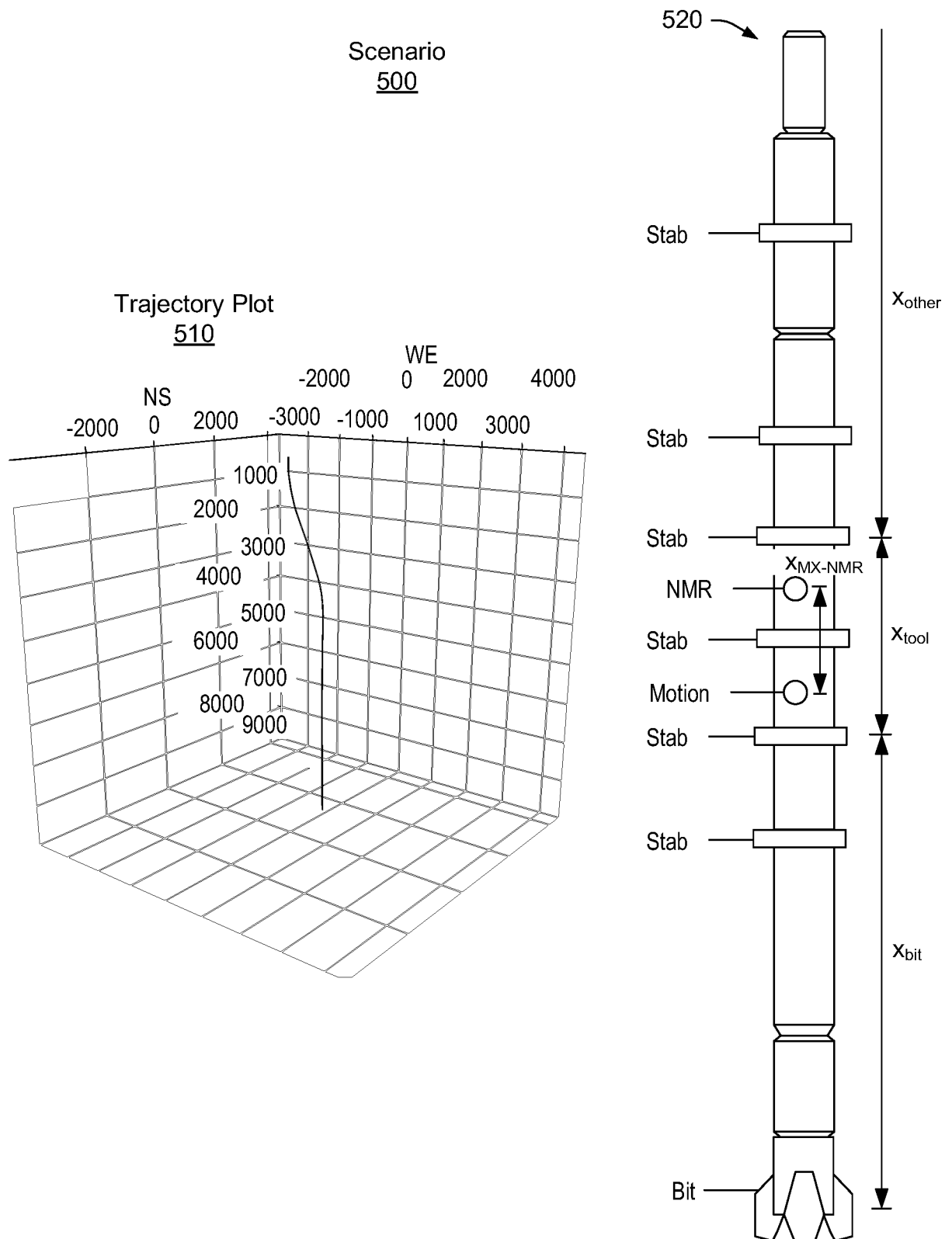


Fig. 5

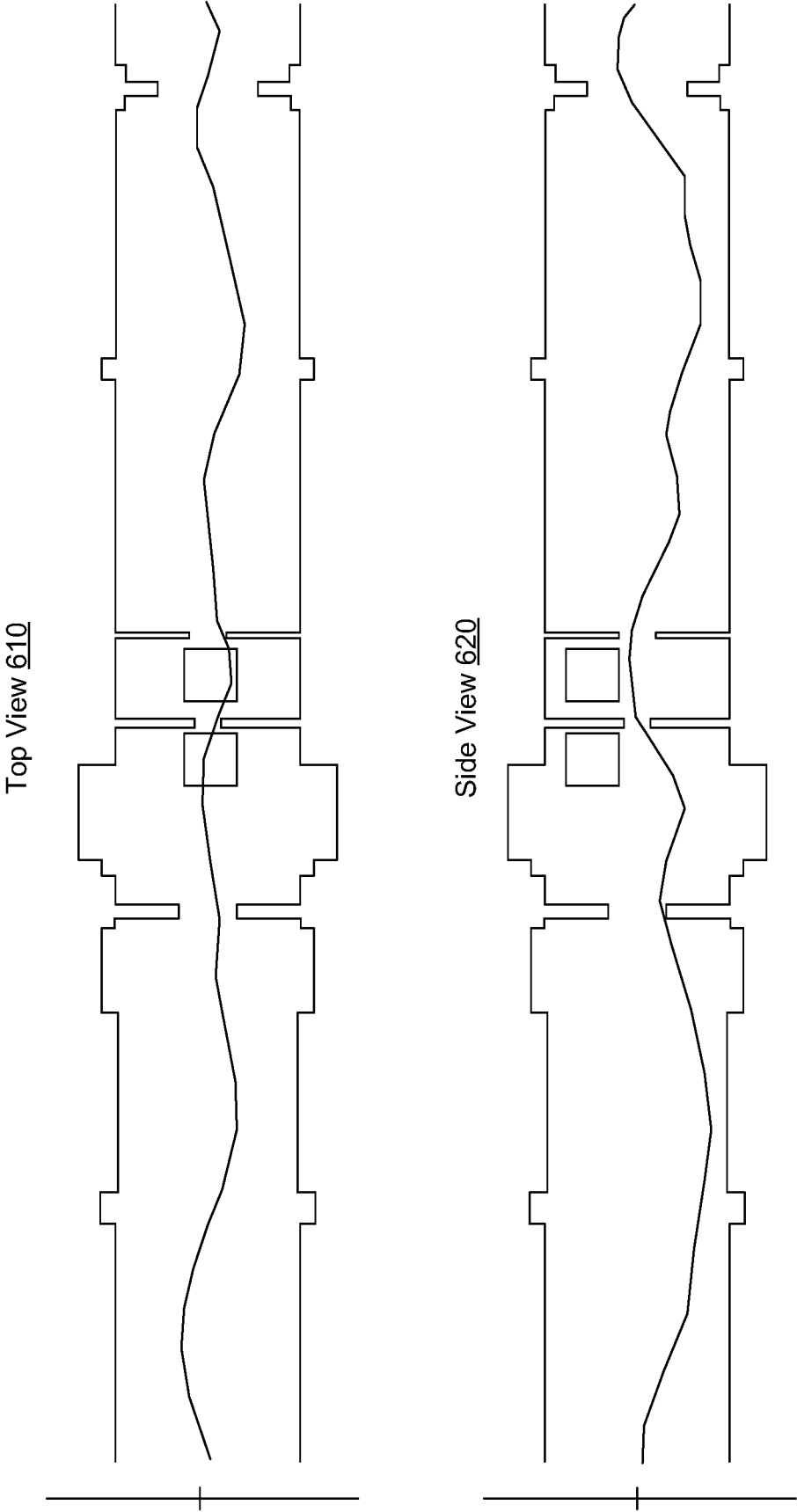
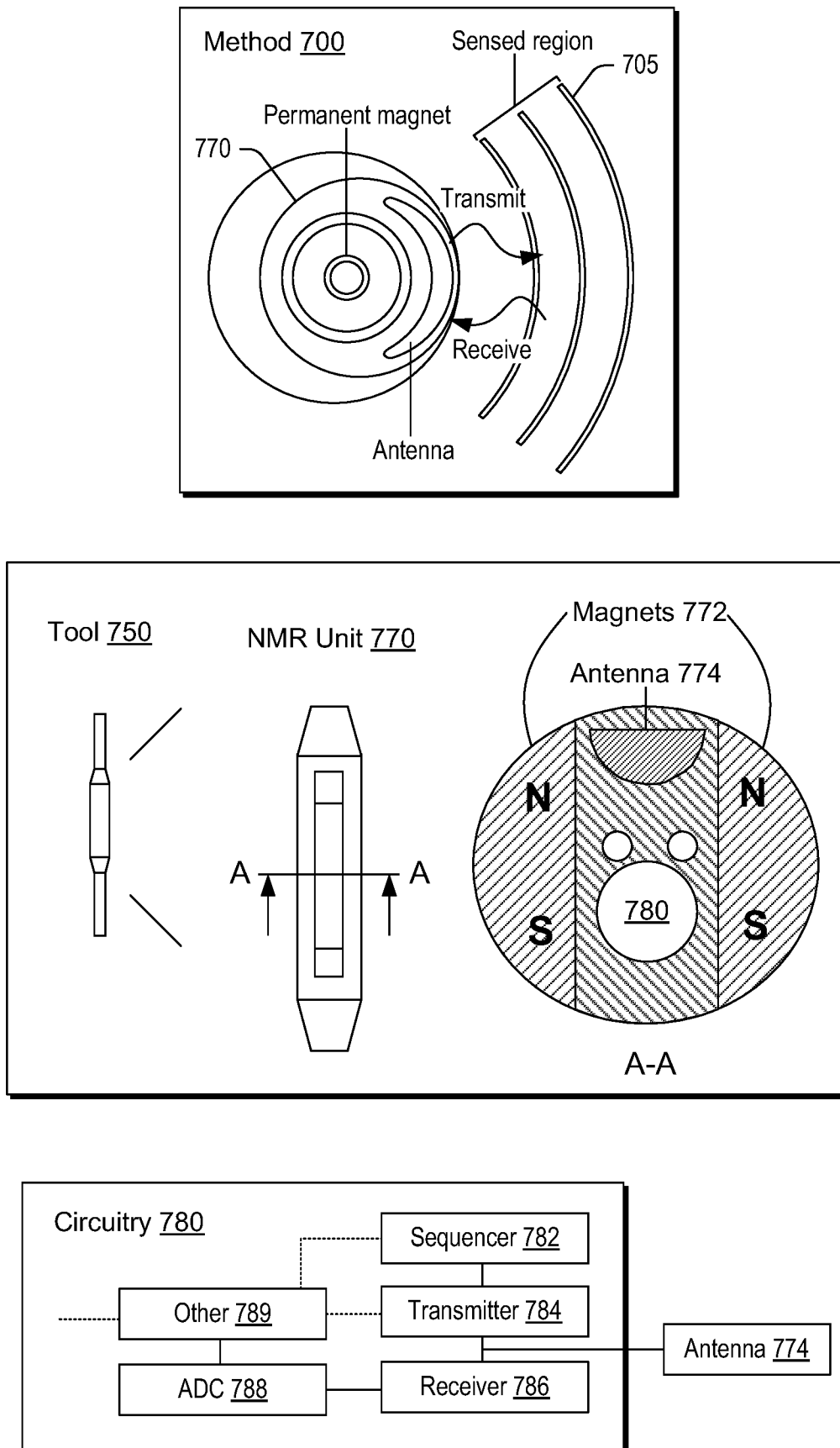


Fig. 6

**Fig. 7**

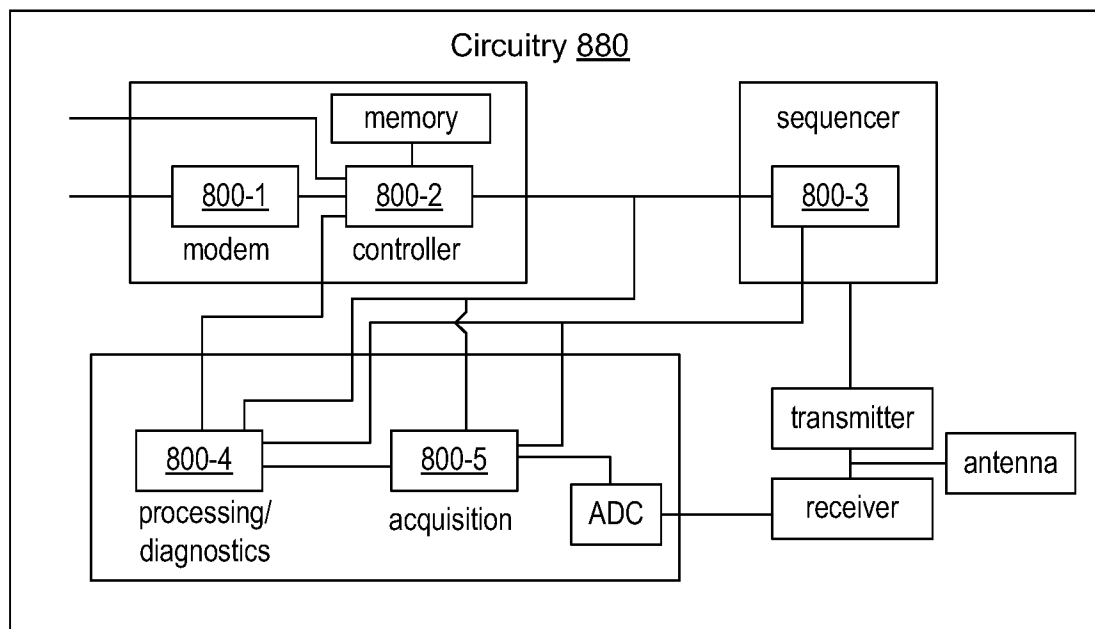
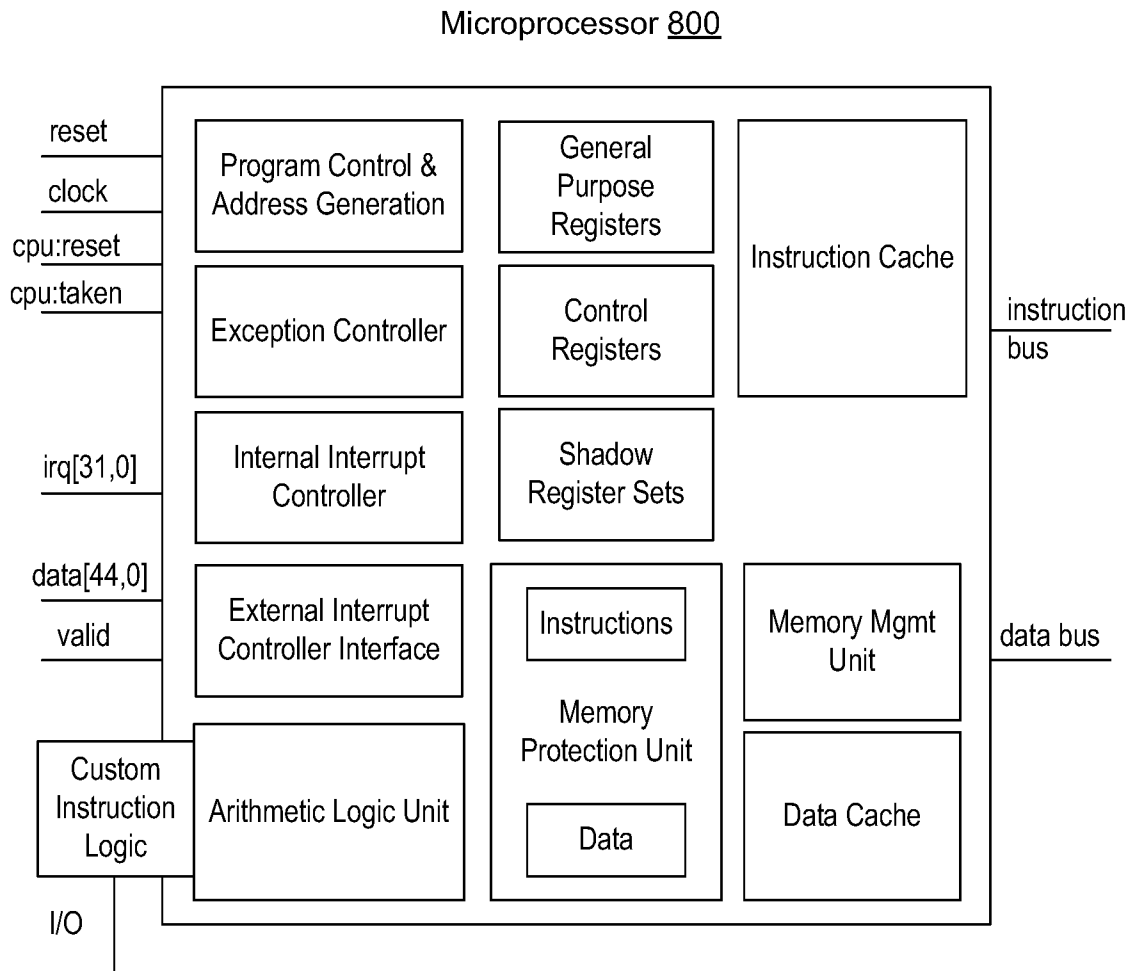


Fig. 8

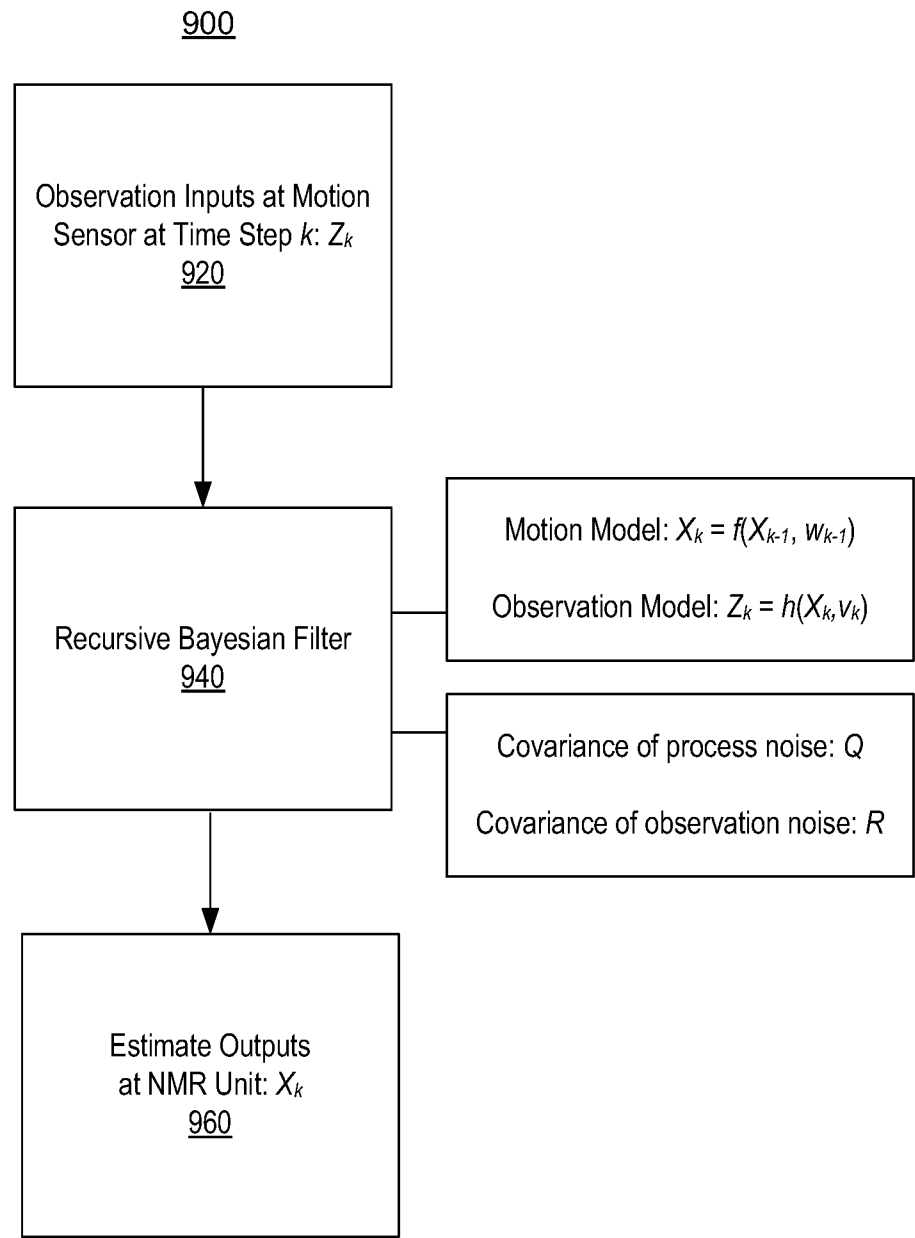


Fig. 9

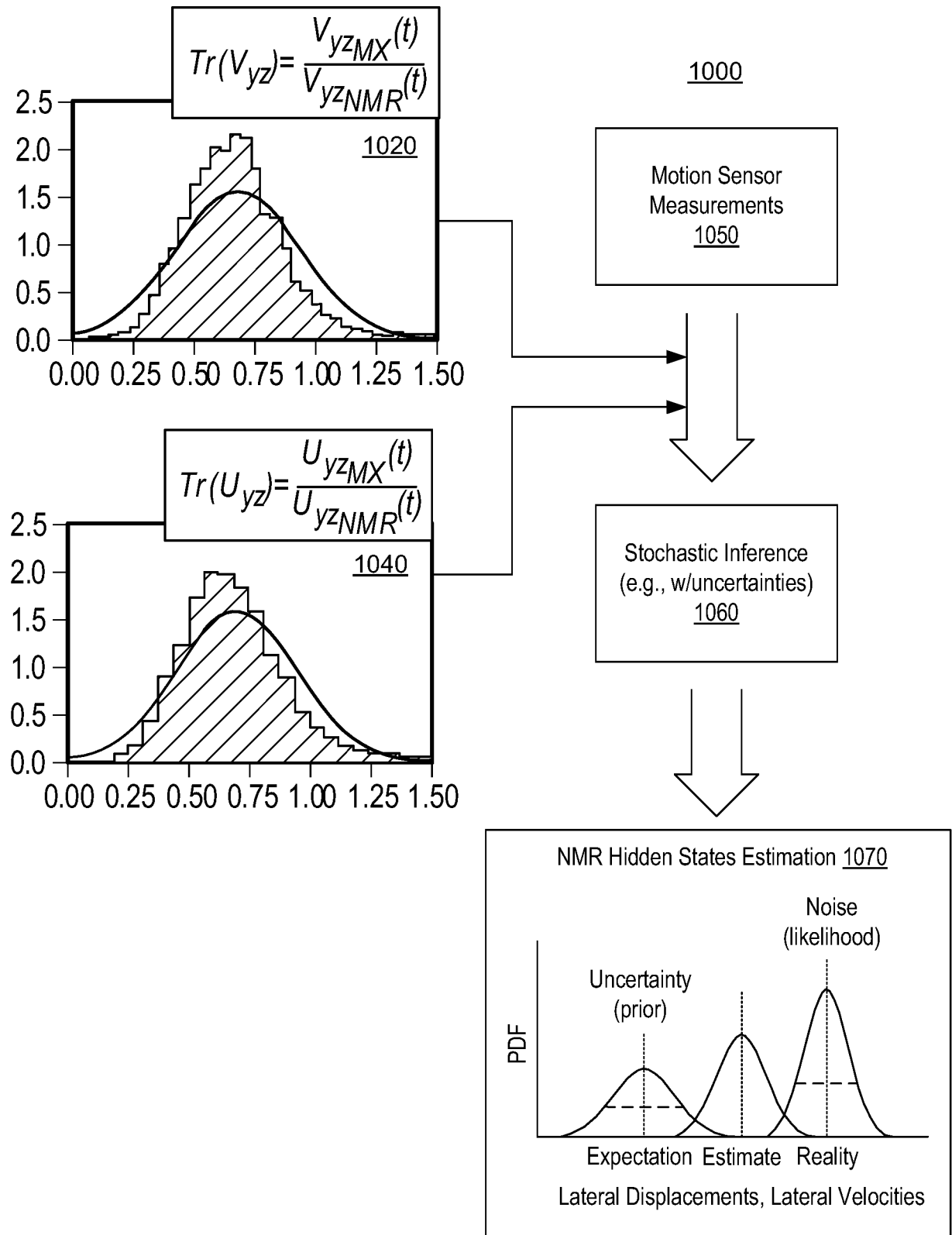


Fig. 10

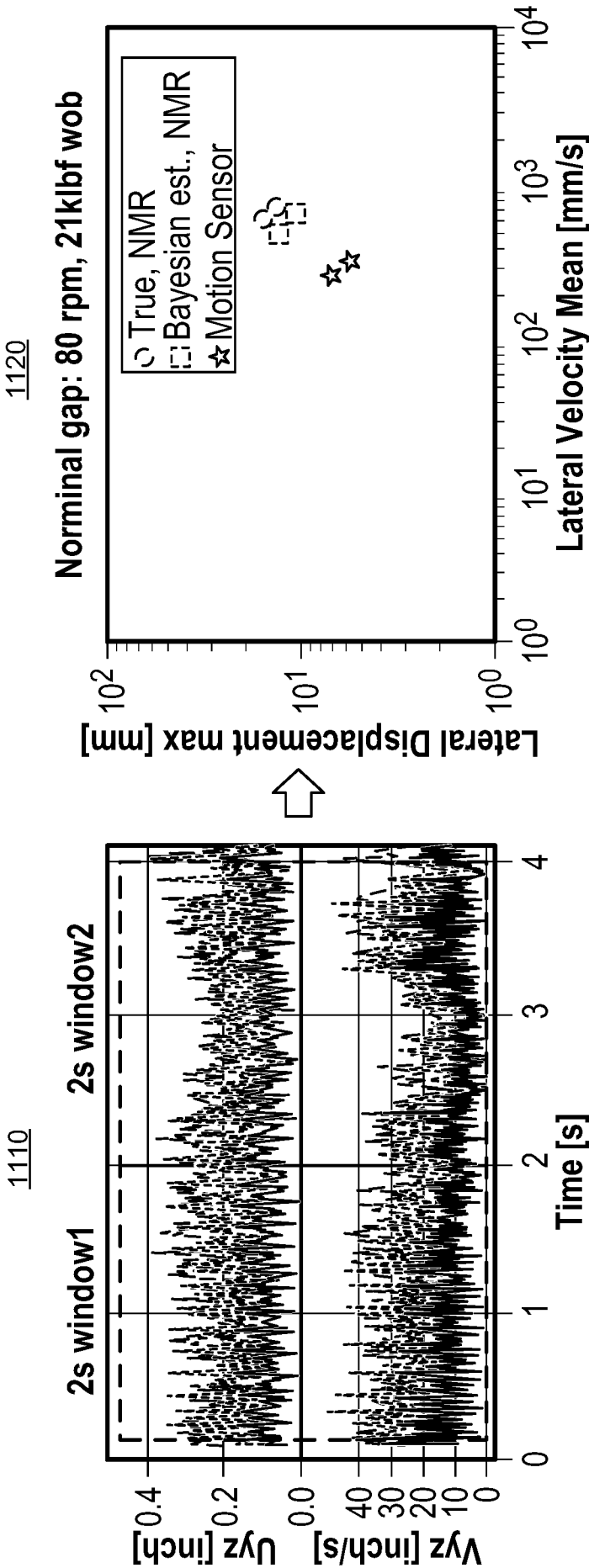
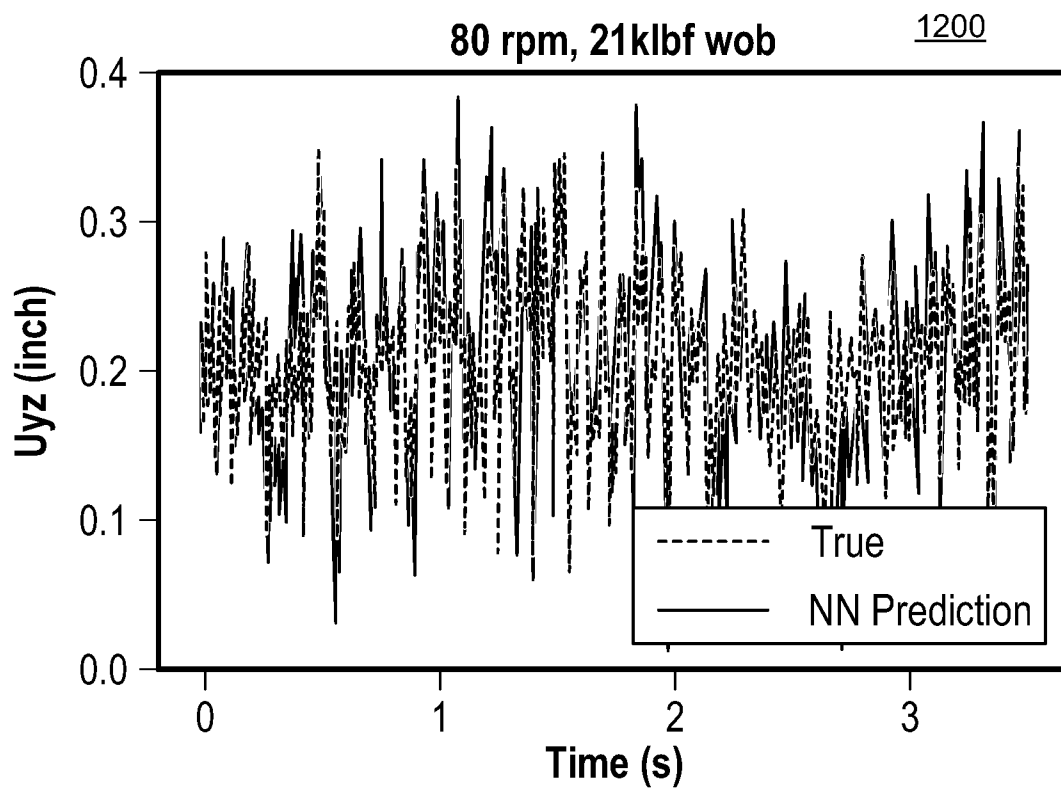
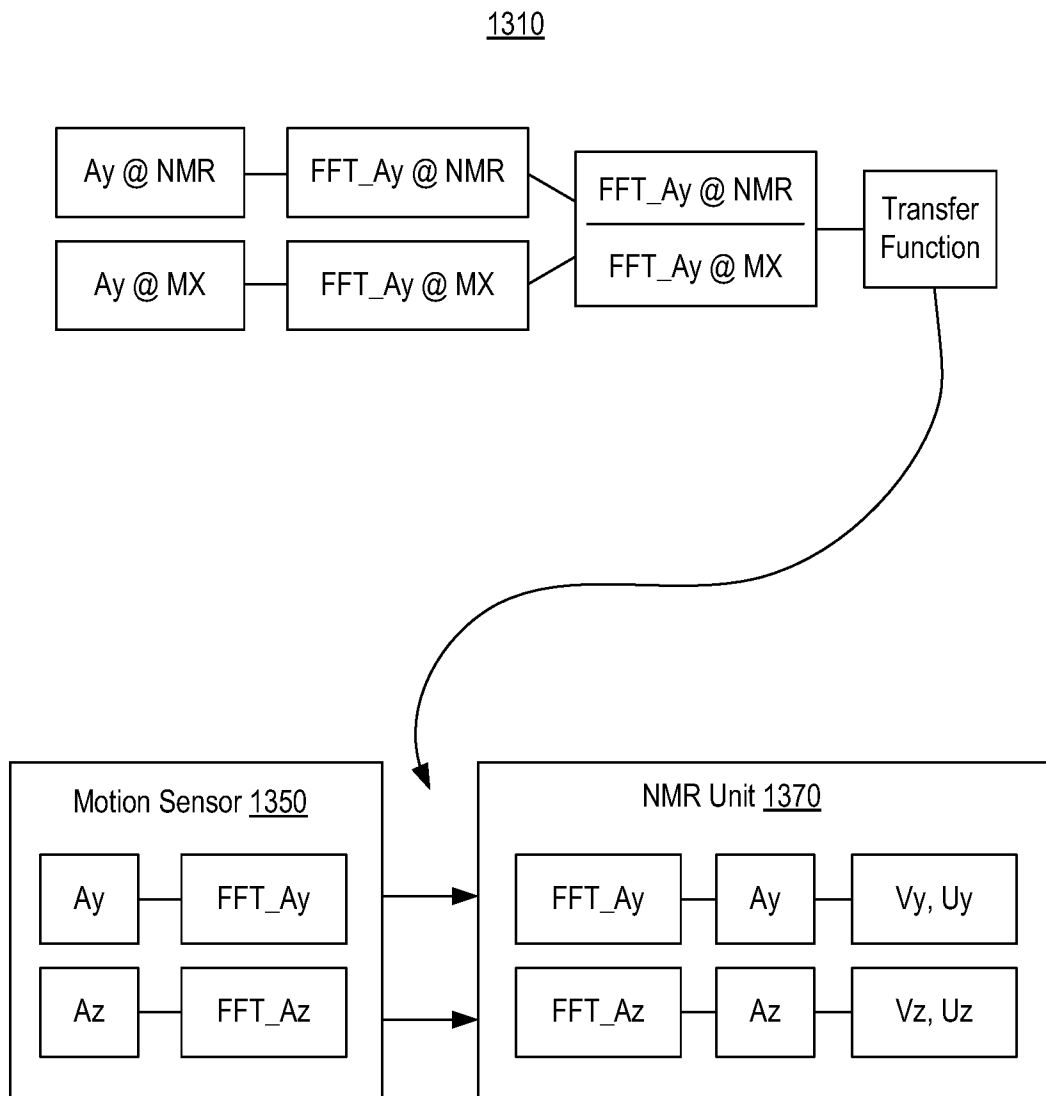


Fig. 11

**Fig. 12**

**Fig. 13**

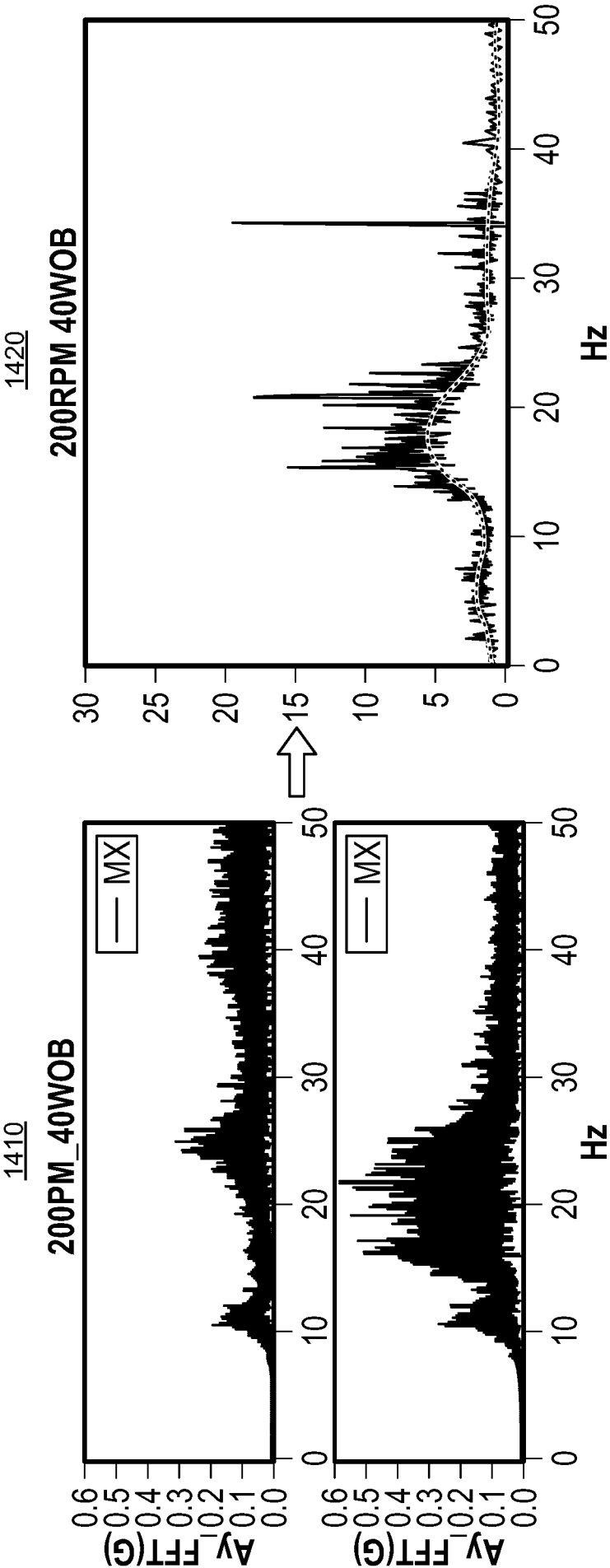


Fig. 14

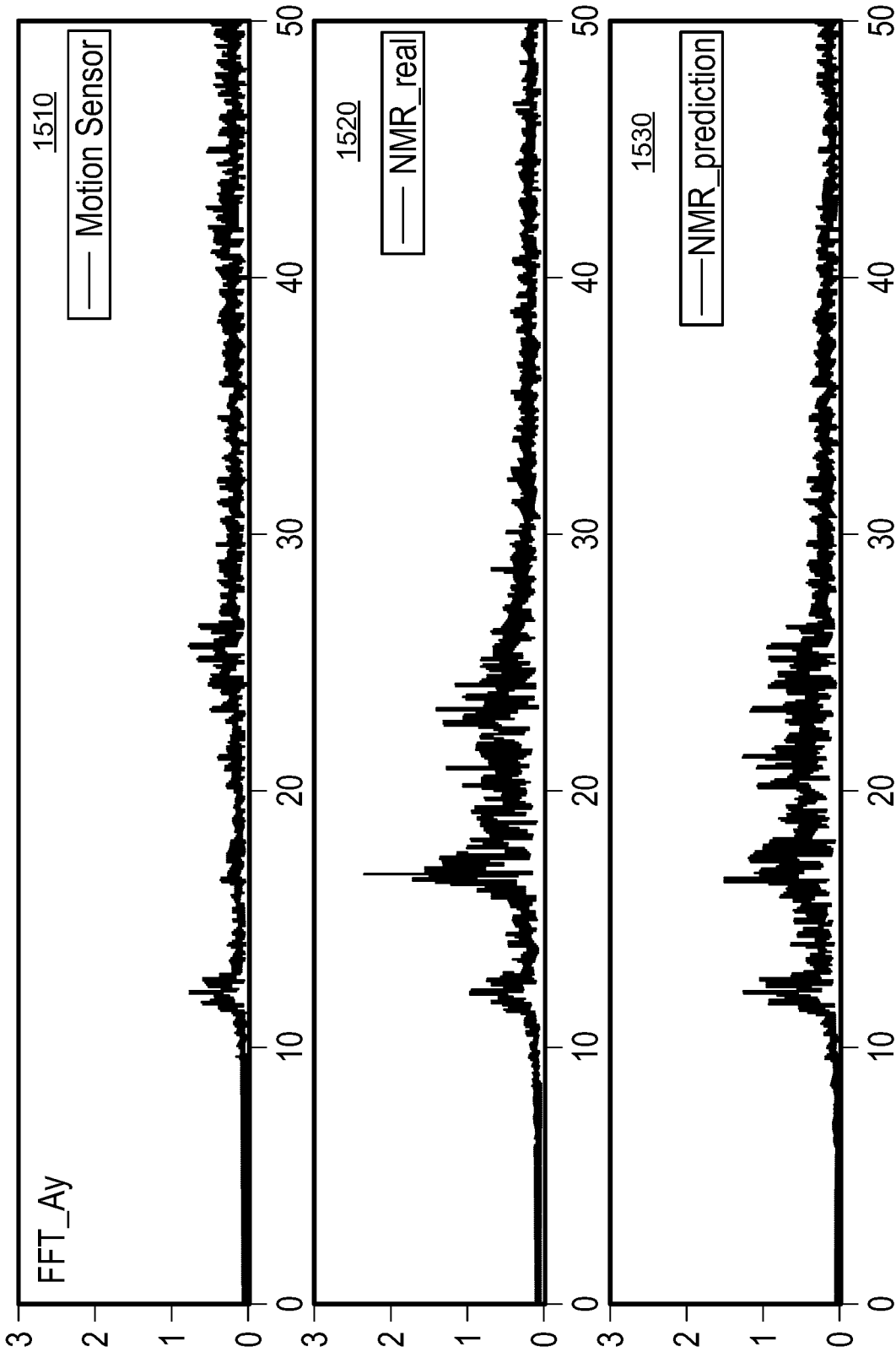


Fig. 15

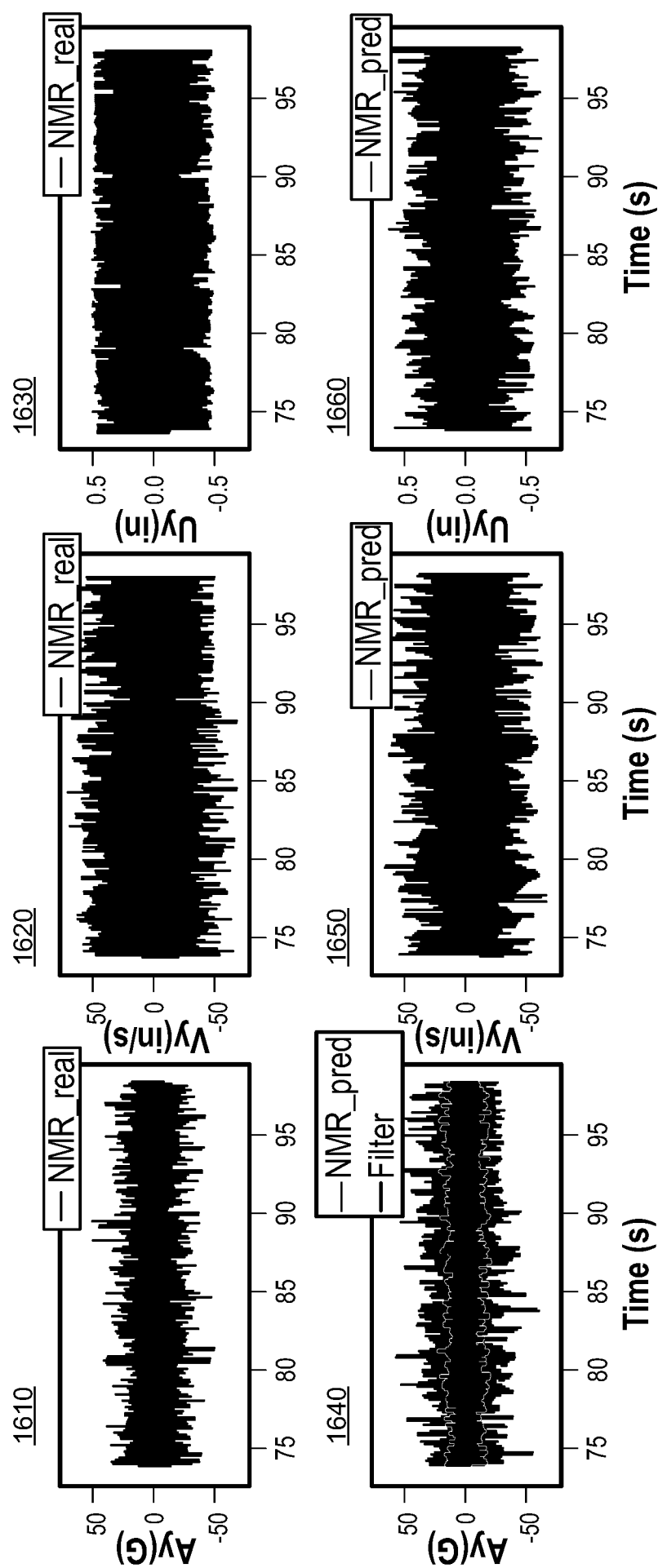


Fig. 16



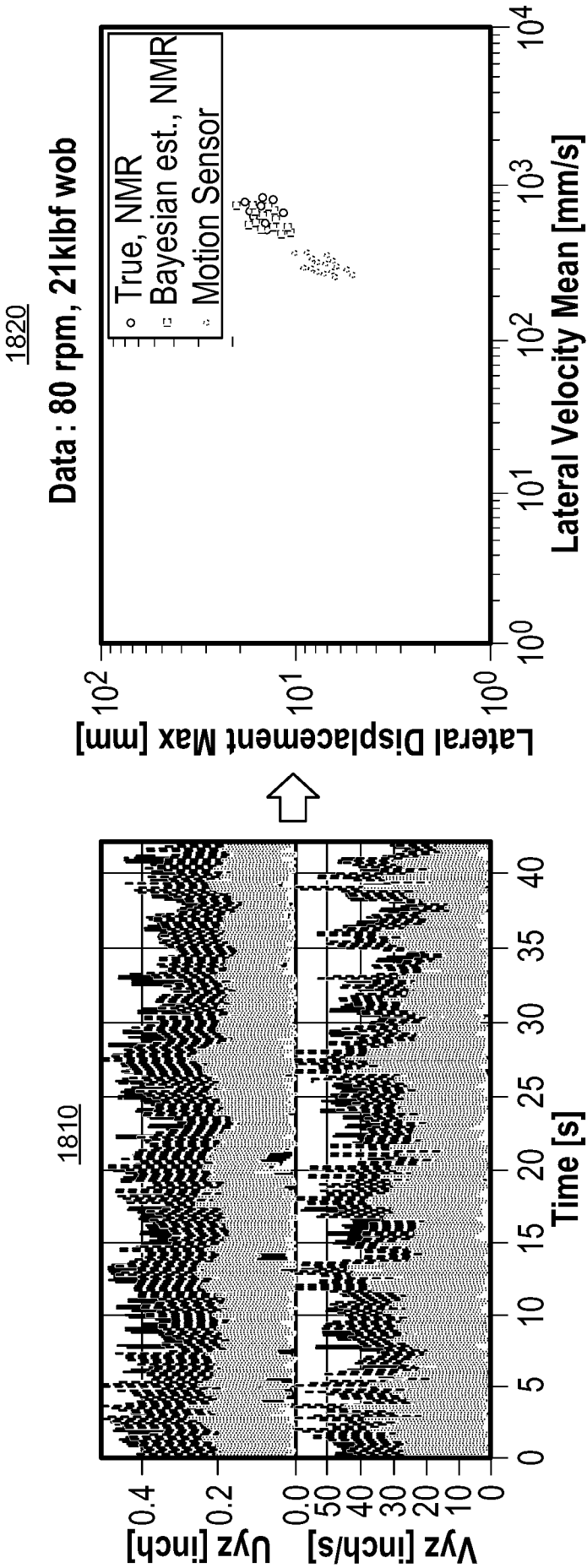


Fig. 18

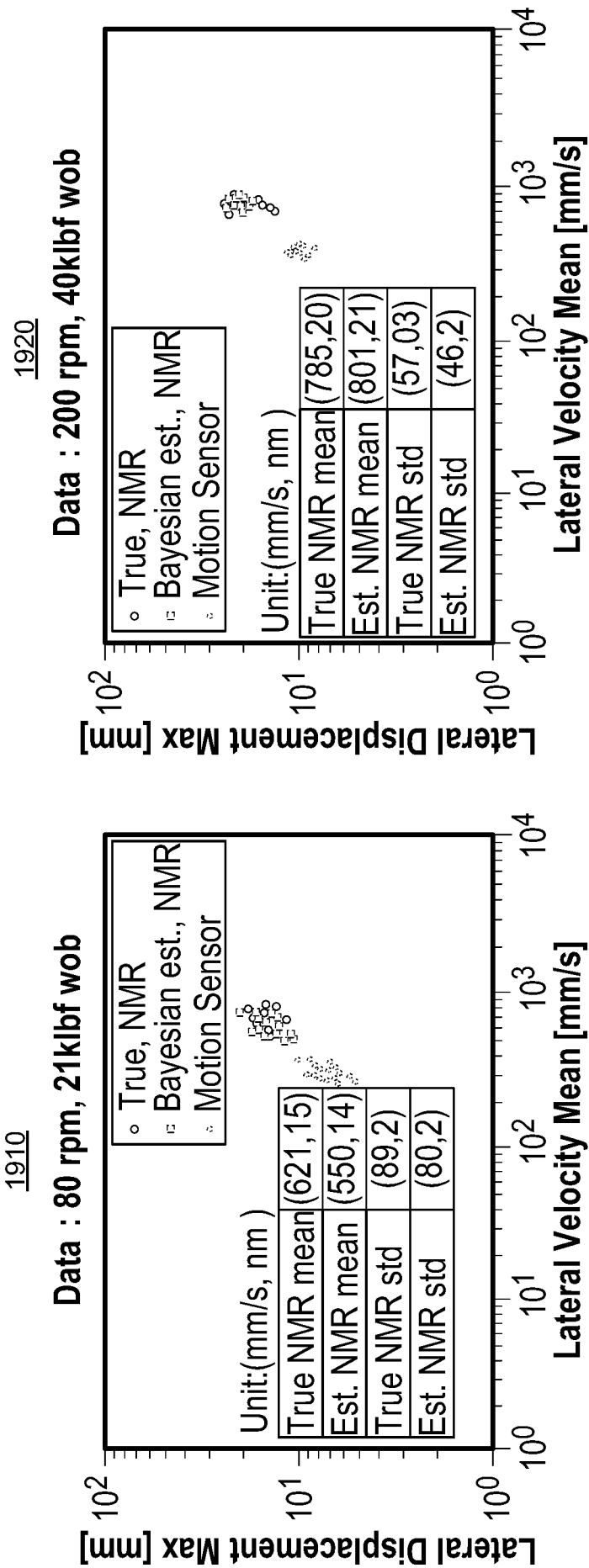


Fig. 19

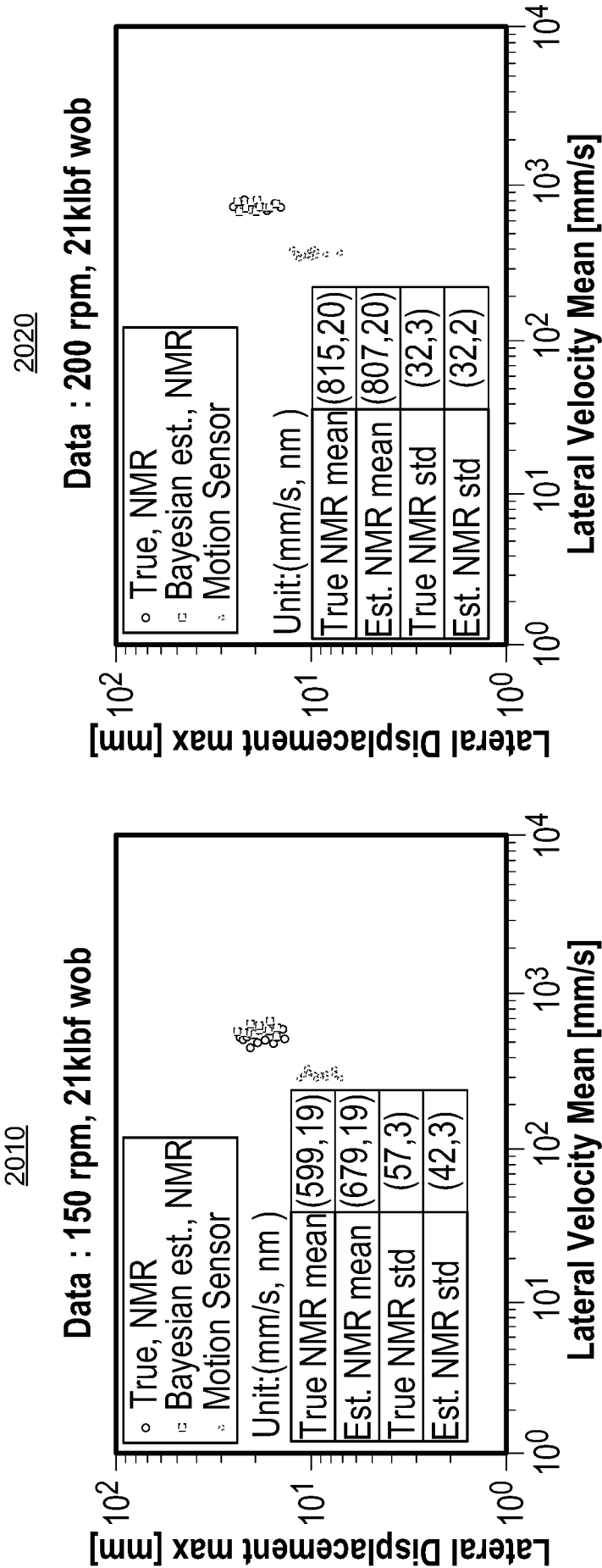
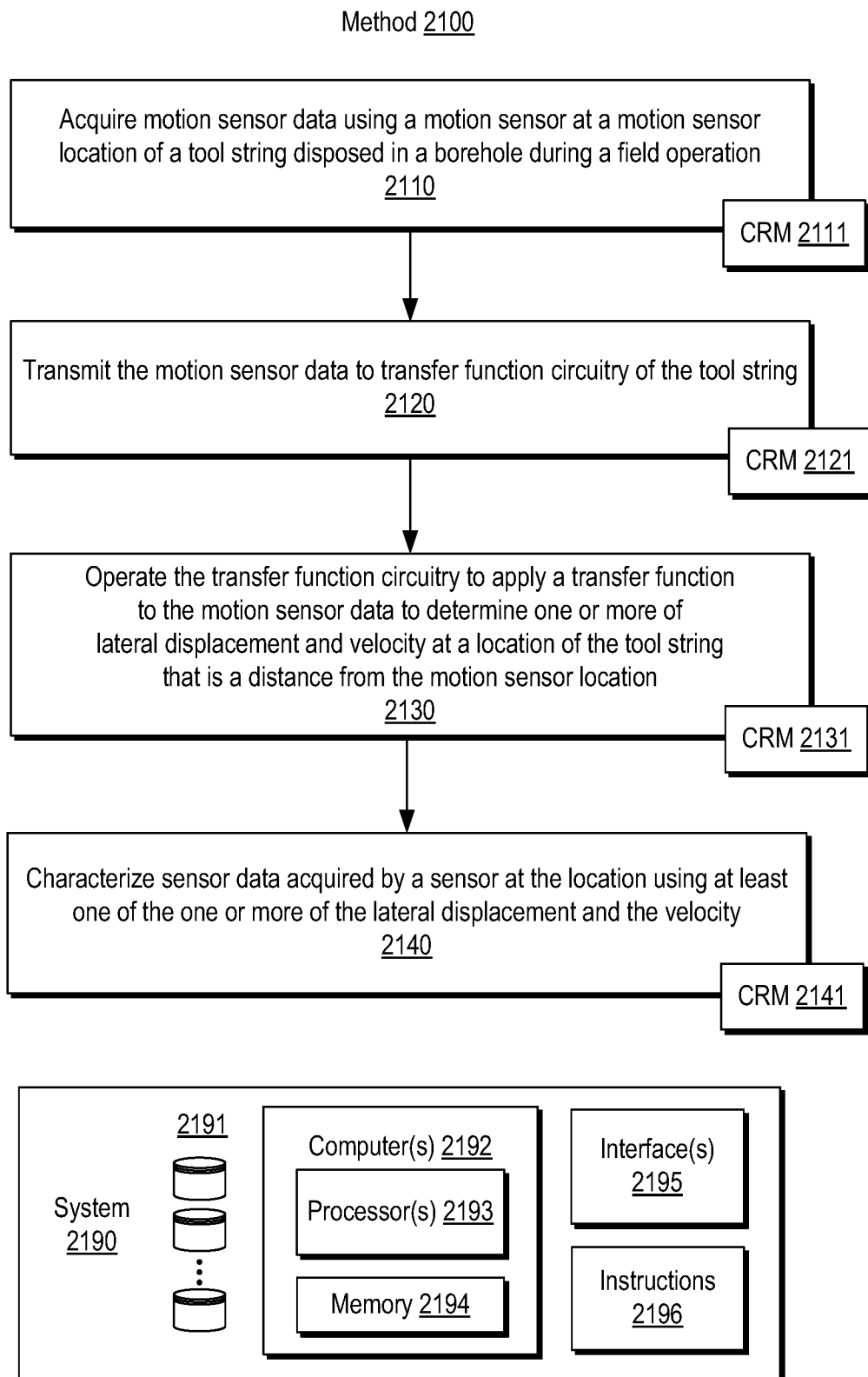


Fig. 20

**Fig. 21**

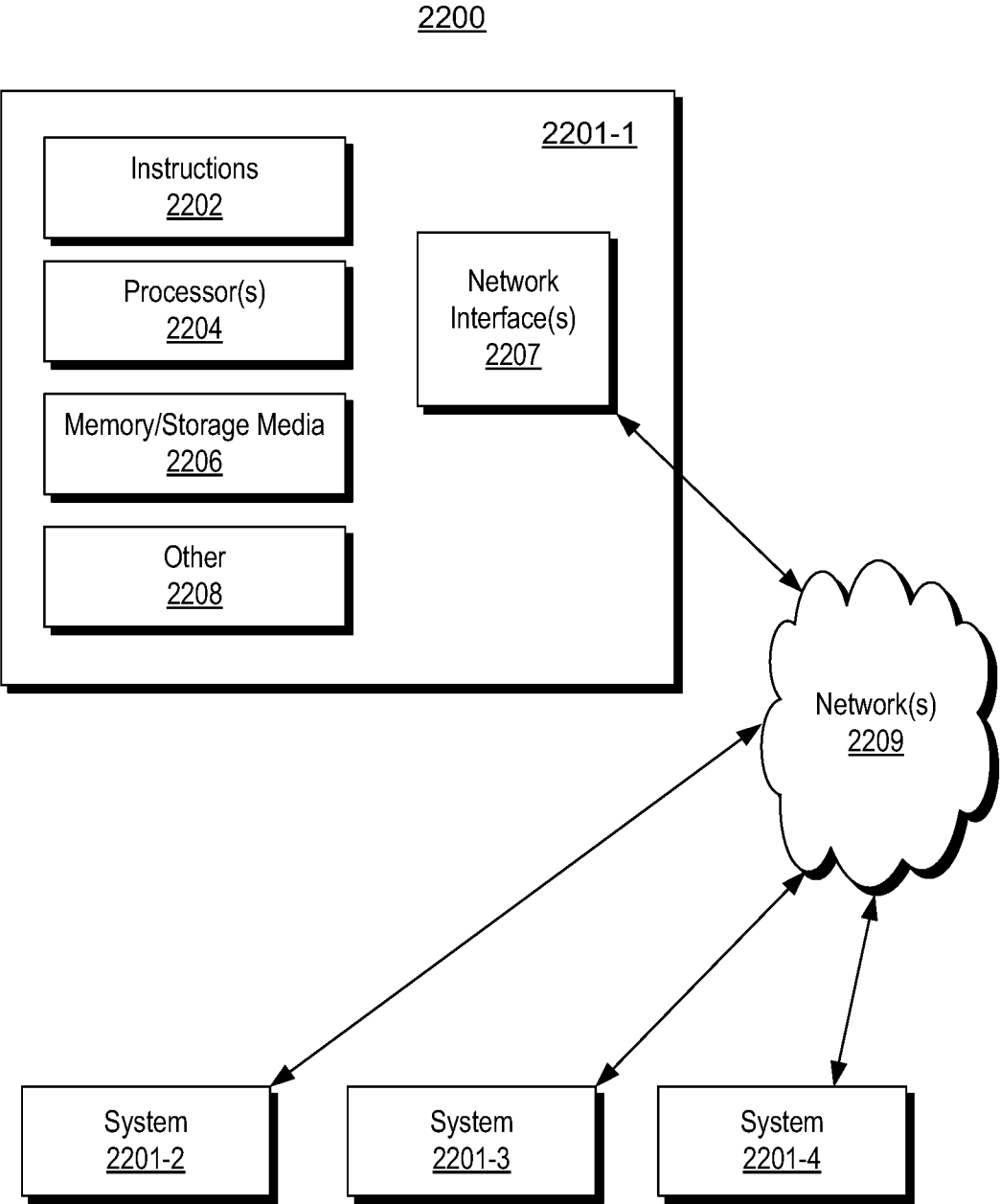


Fig. 22

INTERNATIONAL SEARCH REPORT

International application No.

PCT/US2023/081750

A. CLASSIFICATION OF SUBJECT MATTER G01V 3/32(2006.01)i; E21B 47/12(2006.01)i; G06N 20/00(2019.01)i According to International Patent Classification (IPC) or to both national classification and IPC		
B. FIELDS SEARCHED Minimum documentation searched (classification system followed by classification symbols) G01V 3/32(2006.01); E21B 47/00(2006.01); E21B 47/10(2006.01); G01V 3/10(2006.01); G01V 3/38(2006.01) Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched Korean utility models and applications for utility models Japanese utility models and applications for utility models Electronic data base consulted during the international search (name of data base and, where practicable, search terms used) eKOMPASS(KIPO internal) & Keywords: downhole, motion sensor, NMR, location, displacement, velocity, distance, characterizing		
C. DOCUMENTS CONSIDERED TO BE RELEVANT		
Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	WO 2022-256527 A1 (SCHLUMBERGER TECHNOLOGY CORPORATION et al.) 08 December 2022 (2022-12-08) paragraphs [0026]-[0029], [0053], [0056], [0061], [0065], [0082], claims 1-3, 6, 11, 14-20, and figures 1, 8-9	1,6-8,13-20
Y		9-12
A		2-5
Y	WO 2019-135752 A1 (HALLIBURTON ENERGY SERVICES, INC.) 11 July 2019 (2019-07-11) paragraphs [0031], [0034], [0105] and figures 1B, 2A	9-12
A	US 2016-0202384 A1 (SCHLUMBERGER TECHNOLOGY CORPORATION) 14 July 2016 (2016-07-14) claim 1 and figures 1-2, 12	1-20
A	US 8305081 B2 (ARCADY REIDERMAN et al.) 06 November 2012 (2012-11-06) claim 1 and figures 1, 4-5	1-20
☒ Further documents are listed in the continuation of Box C. ☒ See patent family annex.		
* Special categories of cited documents: "A" document defining the general state of the art which is not considered to be of particular relevance "D" document cited by the applicant in the international application "E" earlier application or patent but published on or after the international filing date "L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified) "O" document referring to an oral disclosure, use, exhibition or other means "P" document published prior to the international filing date but later than the priority date claimed "T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention "X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone "Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art "&" document member of the same patent family		
Date of the actual completion of the international search 25 March 2024		Date of mailing of the international search report 25 March 2024
Name and mailing address of the ISA/KR Korean Intellectual Property Office 189 Cheongsa-ro, Seo-gu, Daejeon 35208, Republic of Korea Facsimile No. +82-42-481-8578		Authorized officer PARK, Tae Wook Telephone No. +82-42-481-3405

INTERNATIONAL SEARCH REPORT

International application No.

PCT/US2023/081750

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 2021-0063600 A1 (HALLIBURTON ENERGY SERVICES, INC.) 04 March 2021 (2021-03-04) claim 1 and figures 1-3	1-20

INTERNATIONAL SEARCH REPORT
Information on patent family members

International application No.

PCT/US2023/081750

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				WO	2019-164524	A1	29 August 2019