Innovation, Sciences et Développement économique Canada
Office de la Propriété Intellectuelle du Canada

Innovation, Science and Economic Development Canada
Canadian Intellectual Property Office

CA 3000322 A1 2013/04/18

(21) 3 000 322

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) Date de dépôt/Filing Date: 2012/10/09

(41) Mise à la disp. pub./Open to Public Insp.: 2013/04/18

(62) Demande originale/Original Application: 2 849 825

(30) Priorité/Priority: 2011/10/09 (US13/269,596)

(51) Cl.Int./Int.Cl. *E21B 47/085* (2012.01), *E21B 41/00* (2006.01), *E21B 43/30* (2006.01), *E21B 47/0224* (2012.01), *E21B 43/26* (2006.01)

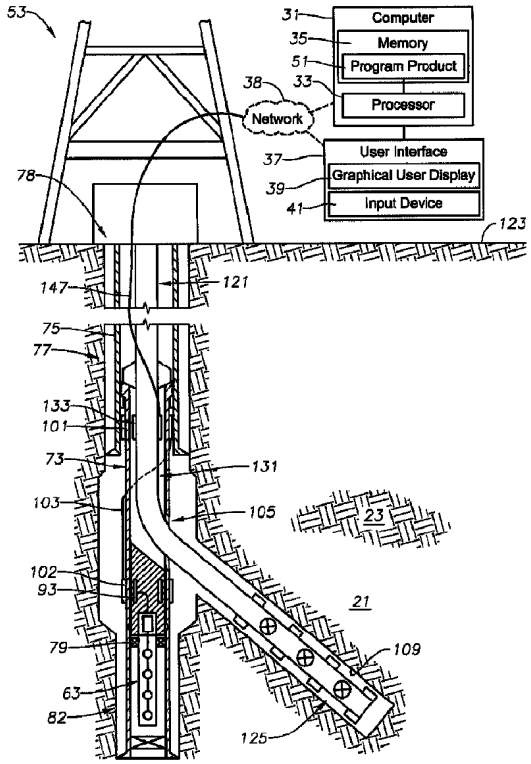
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(54) Titre : PROCEDE DE CONTROLE ET DE TRANSMISSION EN TEMPS REEL VERS LA SURFACE D'EVENEMENTS SISMIQUES DANS UNE FRACTURE HYDRAULIQUE PAR L'AVANT-TROU DU PUITS DE TRAITEMENT UTILISE COMME PUITS DE SURVEILLANCE

(54) Title: METHOD FOR REAL-TIME MONITORING AND TRANSMITTING HYDRAULIC FRACTURE SEISMIC EVENTS TO SURFACE USING THE PILOT HOLE OF THE TREATMENT WELL AS THE MONITORING WELL



(57) Abrégé/Abstract:
Methods for determining hydraulic fracture geometry and/or areal extent of an area of interest (21) in a reservoir (23), are provided. An exemplary method includes isolating downhole acoustic receiver equipment (63) in a lower portion of a first wellbore (78) from

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(21) 3 000 322

(13) A1

(57) Abrégé(suite)/Abstract(continued):
fracturing operations located in a second wellbore (109) connected to the first wellbore (78). Communications between surface equipment (31, 38) in the downhole acoustic receiver equipment (63) is provided through a communications conduit bypass (101, 133; 103; 102, 93) that permits well operations in the second wellbore (109) without interfering with communications between the surface equipment (31, 38) and the downhole acoustic receiver equipment (63).

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METHOD FOR REAL-TIME MONITORING AND TRANSMITTING HYDRAULIC FRACTURE SEISMIC EVENTS TO SURFACE USING THE PILOT HOLE OF THE TREATMENT WELL AS THE MONITORING WELL

ABSTRACT

Methods for determining hydraulic fracture geometry and/or areal extent of an area of interest (21) in a reservoir (23), are provided. An exemplary method includes isolating downhole acoustic receiver equipment (63) in a lower portion of a first wellbore (78) from fracturing operations located in a second wellbore (109) connected to the first wellbore (78). Communications between surface equipment (31, 38) in the downhole acoustic receiver equipment (63) is provided through a communications conduit bypass (101, 133; 103; 102, 93) that permits well operations in the second wellbore (109) without interfering with communications between the surface equipment (31, 38) and the downhole acoustic receiver equipment (63).

METHOD FOR REAL-TIME MONITORING AND TRANSMITTING HYDRAULIC FRACTURE SEISMIC EVENTS TO SURFACE USING THE PILOT HOLE OF THE TREATMENT WELL AS THE MONITORING WELL

This application is a division of application no. 2,849,825 filed in Canada on October 9, 2012 upon the National Entry of PCT/US2012/059361.

BACKGROUND OF THE INVENTION

1 Field of the Invention

[0001] The present invention relates in general to the field of hydraulic fracturing, monitoring, and data transmission of microseismic information from a zone of interest within a reservoir, and more particularly, to the utilization and employment of electrically and physically isolated downhole acoustic monitoring equipment within a fracturing treatment well to detect microseismic events during fracturing operations.

2. Description of the Related Art

[0002] Hydraulic fracturing has been used for over 60 years in more than one million wells to improve the productivity of a hydrocarbon bearing formation, particularly those drilled in low permeability reservoirs. An estimated 90% of the natural gas wells in the United States alone use hydraulic fracturing to produce gas at economic rates. Successful hydraulic fracturing is generally considered vital for economic production of natural gas from shale beds and other 'tight gas' plays.

[0003] Fracturing treatment operations are typically employed in vertical, deviated, and horizontal wells. In a typical well development operation, the wellbore of the treatment well is drilled through the desired formation where the fracture treatment will take place.

[0004] The hydraulic fracture is formed by pumping a fluid into the wellbore at a rate sufficient to increase the pressure downhole to a value in excess of the fracture gradient of the formation rock in the area of interest. The pressure causes the formation to crack, allowing the fracturing fluid to enter and extend the crack further into the formation. One method to keep this fracture open after the injection stops is to add a solid proppant to the fracture fluid. The

proppant, which is commonly sieved round sand or other nonporous material, is carried into the fracture. This sand is chosen to be higher in permeability than the surrounding formation, and the propped hydraulic fracture then becomes a high permeability conduit through which the formation fluids can flow to the well.

[0005] Determining the size and orientation of completed hydraulic fractures is quite difficult and expensive, and in less expensive alternatives, highly inaccurate. It is well known that hydraulic fractures create a series of small "earthquakes" that can be mapped to show the position of the fracture event. The technology currently in use deploys a series of microseismic detectors typically in the form of geophones inside a separate monitoring well to measure fracturing events while pumping a hydraulic fracture treatment. Deployment of geophones or tilt meters on the surface can also be used, but the resolution is significantly less as you go deeper in the well.

[0006] Tiltmeter arrays, deployed on the surface or in a nearby monitoring well, measure the horizontal gradient of the vertical displacement. Microseismic detector arrays, deployed in a nearby monitoring well or on the surface adjacent the zone of interest if it is not too deep and/or environmental noise is not too excessive, can detect individual microseismic events associated with discrete fracture opening events. The microseismic event can be located in three dimensions by a triangulation methodology based on comparing acoustic arrival times at various sensors in a receiver array. By mapping the location of small seismic events that are associated with the growing hydraulic fracture during the fracturing process, the approximate geometry of the fracture can be inferred.

[0007] Although the use of a monitoring well located separate from the treatment well is often preferred as it provides improved accuracy, particularly in areas with high environmental noise and/or relatively inaccessible surface conditions, the cost of drilling a monitor well is typically in the area of $10 million and requires 30-50 days of drilling rig time. Further, availability of surface real estate or other factors can prevent the monitoring well from being drilled sufficiently close to the area of interest, and thus, results in a degraded performance.

[0008] In order to try to reduce capital costs and deployment time, some progressive operators have, with minimal success, attempted to build a combination monitoring and

treatment well by placing the acoustical sensors in the annulus of the treatment well. Some other operators, have instead chosen to deploy the acoustic sensors directly in the treatment flow path.

[0009] Recognized by the inventors, however, is that as a result of the pumping of the fracturing fluid, such acoustic sensors located along the annulus of the treatment well or within the flow path encounter substantial noise during the hydraulic fracturing events, which in turn, results in the collection of acoustic data having an excessively low signal-to-noise ratio. Accordingly, also recognized by the inventors is that this type of monitoring can generally only provide usable data when the fracture is closing, and thus, causes the operator to miss the fracturing events occurring while pumping the fracturing slurry.

[00010] Further recognized by the inventors is that due to the exposure limitations of the electrical data/power conduit (e.g., run with the acoustic sensors to transmit data to the surface), the operator is limited to certain slurry concentrations and is limited by the amount of total pressure that can be applied while fracturing due to the pressure limitation of the electric line cable heads. Still further, recognized by the inventors is that the deployment of acoustic sensors within the treatment flow or in the annulus adjacent current or potential future sidetracking operations can impede such operations.

[00011] Recognized, therefore, by the inventors is that there is a need for systems and processes that requires only a single treatment well to reduce capital costs and deployment time, that includes provisions for isolating the acoustic sensors to provide for gathering during pumping of the fracturing slurry downhole, acoustic data having an acceptable signal-to-noise ratio. Also recognized by the inventors is that there is a need for systems and processes that allow for high slurry concentrations and that allow for a total pressure necessary for optimal fracturing without concern for the pressure limitations of electric conduit/line cable heads in the communication pathway of the acoustic sensors, and/or that does not impede current or future sidetracking operations.

SUMMARY OF THE INVENTION

[00012] In view of the foregoing, various embodiments of the present invention advantageously provide systems and methods of/processes for determining hydraulic fracture geometry and areal extent of a zone of interest, that require utilization of only portions of a single

treatment well to reduce capital costs and deployment time, that includes provisions for isolating acoustic monitoring sensors to provide for gathering acoustic data having an acceptable signal-to-noise ratio real-time during pumping of the fracturing slurry, that allows for high slurry concentrations, that allows for a total pressure necessary for optimal fracturing, without concern for the pressure limitations of the electric line cable heads, and/or that does not impede current or future sidetracking operations, and that can be employed for seismic monitoring in all types of hydraulic fracture operations, including fracturing unconventional or shale gas reservoirs.

[00013] More specifically, an example of an embodiment of a method to determine hydraulic fracture geometry and areal extent of a zone of interest in a reservoir, can include various steps including those to establish the well and to deploy the acoustic and communications equipment. According to an embodiment of the present invention, a well is drilled through a zone of interest and is either cased and cemented or left in an openhole environment. A kickover or other deflection-type tool is then deployed with the geophones or other acoustic receivers hung below at predetermined intervals to capture fracture events below, above and within the zone of interest. The geophones or other acoustic receivers are coupled to the casing or open hole section. Coupling of the geophones or other acoustic receivers can be accomplished by cementing them in place or hanging the geophones or other acoustic receivers in the cased or open hole with centralizers. A packer can also be used to isolate pressure from the fracturing operations and to isolate the geophones. If left un-cemented the deployed kickover/deflecting tool and geophones or other acoustic receivers can be retrieved at a later date.

[00014] During fracturing operations, data is transmitted up hole using, for example, a down hole electrical coupler to make an electrical connection down hole in well test operations. Utilization of coupling device can advantageously remove any physical contact between electrical connections and wellbore fluids. According to an exemplary configuration, power and/or communication signals are transmitted through the coupler via an A/C current that creates an electromagnetic (EM) field transmitted to the female coupler. As such, an advantage of this system is the positive power and communication provided across the coupling device.

[00015] Upon completion of the fracturing operation, a surface computer having received the acoustic data describing each microseismic fracture and then producing and graphically displaying a map of the hydraulic fracture geometry and extent of such fracturing.

[00016] According to another embodiment of a method, the method can include the steps of positioning an acoustic assembly within a first wellbore adjacent the zone of interest in the reservoir and drilled within a portion of a reservoir to receive a hydraulic fracturing treatment defining the zone of interest. The acoustic assembly can include an acoustic receiver controller, e.g., seismic brain, and a set of one or more acoustic sensors, e.g., geophones, tilt meters, etc., to capture fracture events within the zone of interest. The steps can also include isolating the set of one or more acoustic sensors from acoustic interference associated with delivery of fracturing fluid through a conduit string extending through portions of the first wellbore and into the second wellbore when performing the hydraulic fracturing of the reservoir in the zone of interest. Such isolization can advantageously serve to minimize noise encountered by the set of one or more acoustic sensors and associated with movement of fracturing fluid.

[00017] The steps can also include inserting a drilling deflector into the first wellbore, drilling a second wellbore to receive a fracturing fluid, and typically before drilling the second wellbore if not pre-drilled, positioning a communication conduit bypass within the first wellbore to extend from a first location above an interface with the second wellbore to a second location below the interface with the second wellbore.

[00018] The steps can also include detecting microseismic events associated with the performance of the hydraulic fracturing by employing the set of acoustic sensors, and communicating to a surface unit the real-time microseismic event data describing microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest through the second wellbore. In order to provide for such communication, the steps can further include coupling the acoustic receiver controller to a first coupler connected to a first end of the communication conduit bypass and positioned adjacent the second location below the lateral aperture, and coupling surface equipment to a second inductive coupler connected to a second opposite and of the communication conduit bypass and positioned adjacent the first location, for example, above the lateral aperture.

[00019] According to another embodiment of a method, the method can include the steps of positioning a kickover tool within a production liner in a first wellbore drilled within a portion of a reservoir to receive a hydraulic fracturing treatment defining a zone of interest, and positioning an acoustic assembly within the production liner in the first wellbore below major portions of the

kickover tool and adjacent the zone of interest in the reservoir. The acoustic assembly can include an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events below, above, and within the zone of interest. The steps can also include isolating the set of one or more acoustic sensors from acoustic interference associated with delivery of fracturing fluid through a conduit string extending through portions of the first wellbore and into the second wellbore when performing the hydraulic fracturing of the reservoir in the zone of interest to thereby minimize noise encountered by the set of one or more acoustic sensors and associated with movement of fracturing fluid.

[00020] The steps can further include opening a lateral aperture in the production liner to form an entrance to a second wellbore to receive a fracturing fluid, and positioning a communication conduit bypass within the first wellbore to extend from a first location above the lateral aperture to a second location below the lateral aperture. The positioning of the communication conduit bypass is normally accomplished during deployment of the production liner in conjunction with the deployment of the acoustic assembly, and is later completed upon deployment of a tubing string.

[00021] The steps can also include detecting microseismic events associated with the performance of the hydraulic fracturing through employment of the set of acoustic sensors, and communicating to a surface unit, real-time microseismic event data describing microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest. The communications can be enabled by inductively coupling the acoustic receiver controller to a first inductive coupler connected to a first end of the communication conduit bypass and positioned adjacent the second location below the lateral aperture, inductively coupling surface equipment to a second inductive coupler connected to a second opposite and of the communication conduit bypass and positioned adjacent the first location above the lateral aperture.

[00022] According to another embodiment of a method, the method can include the steps of running a lower completion including wellbore sensors attached to a first connector within a tubular, running a communication conduit (lower umbilical) extending from a position outside the tubular adjacent the first connector to a position adjacent an operable position of a second connector, drilling a lateral wellbore oriented at least partially lateral to an orientation of the

tubular and positioned at a location above the first connector and below the second connector, while avoiding intersection with the lower umbilical, and running an upper completion with a communication conduit (upper umbilical) attached to the second connector. The method can also include running a lateral completion attached below the upper completion, and/or providing a reservoir monitoring sensor or sensors with the lateral completion and connecting a lateral umbilical cord to extend from the sensor to a tee connection in the upper umbilical cord. The lateral completion can also carry a plurality of flow management components including inflow control valves, inflow control devices, and/or isolation packers.

[00023] According to an embodiment of the method, the steps can include sensing an acoustic event resulting from hydraulic fracturing of the formation adjacent the producing well and associated with the fracturing operations conducted through the lateral completion. Wellbore sensors, for example, in the form of acoustic sensors are positioned to detect the acoustic event at different times to facilitate locating the acoustic event. The steps can also or alternatively include the plurality of acoustic sensors sensing an acoustic event resulting from hydraulic fracturing associated with a lateral completion of an adjacent well. The steps can also or alternatively include positioning a packer below the lateral wellbore and above the plurality of acoustic sensors to minimize noise associated with movement of fracturing fluid through the lateral completion and encountered by the plurality of acoustic sensors to enhance data quality.

[00024] According to another embodiment of a method, the method can include the steps of providing a plurality of producing wells each producing well including an upper completion, a lower completion, and a lateral completion extending into a lateral wellbore, combining the functions of a subterranean observation well and a subterranean producing well into each separate one of the plurality of producing wells for each of the producing wells, and sensing an acoustic event resulting from hydraulic fracturing associated with the lateral completion of one of the plurality of producing wells. The combining the functions is performed, for example, by positioning a plurality of acoustic sensors in the lower completion, and hydraulically isolating the plurality of acoustic sensors from fracturing fluid flowing through the upper completion and the lateral completion. The isolation is provided via an isolation device such as a packer positioned below the lateral wellbore and above the plurality of acoustic sensors to minimize noise associated with movement of the fracturing fluid through the lateral completion and encountered by the plurality of acoustic sensors. Additionally, the sensing is advantageously

performed by one or more of the plurality of acoustic sensors in at least two of the plurality of producing wells to enhance data accuracy.

[00025] According to an example of an embodiment of the present invention, a system to determine hydraulic fracture geometry and areal extent of a zone of interest in a reservoir, can include a main casing string extending within a first portion of a first wellbore, and a production liner connected to an inner surface of a portion of the casing string and extending into a second portion of the first wellbore and having a lateral aperture adjacent an opening into a lateral branch wellbore. The system can also include a kickover or other deflection tool positioned within the production liner at a location below major portions of the lateral aperture to facilitate the performance of drilling operations associated with the lateral branch wellbore and to isolate an acoustic assembly positioned within the production liner below the kickover tool adjacent a zone of interest from fracturing operations. The acoustic assembly can include an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events below, above, and within the zone of interest.

[00026] The system can also include a packer positioned within a bore of the production liner below major portions of the kickover tool and at a location above the set of one or more acoustic sensors to isolate the set of one or more acoustic sensors from acoustic interference associated with delivery of the fracturing fluid and/or can include a packer positioned within the bore of the production liner at a location below the set of acoustic sensors to hydraulically isolate the acoustic sensors within the bore of the production liner and/or to reduce acoustic interference from the fracturing components of the system.

[00027] The system also includes a tubing string extending through the first portion of the first wellbore, an upper portion of the second portion of the first wellbore, the lateral aperture, and portions of the lateral branch wellbore to deliver a fracturing fluid, and an inductive communication assembly positioned to receive data signals from the acoustic receiver controller and/or to provide power thereto and positioned to provide electrical isolation between lower completion equipment and upper completion equipment. According to a preferred configuration, the inductive communication assembly includes a communication conduit bypass positioned within the first wellbore and extending from a location above the lateral aperture to a location below the lateral aperture to prevent interference with the fracturing equipment or deployment

thereof. Advantageously, the inductive communications assembly includes two sets of inductive couplings to isolate up hole communication components from the communication components adjacent the lateral branch wellbore and to isolate such communication components from the acoustic assembly components located below the kickover tool. Notably, desired electrical and physical isolations can be achieved by using such inductive coupling technology to connect surface equipment with the downhole acoustic monitoring equipment.

[00028] A system according to another embodiment of the present invention can include a first wellbore including a first portion containing fluid delivery conduits and a second portion containing an acoustic assembly positioned adjacent a zone of interest within a reservoir. The acoustic assembly can include an acoustic receiver controller and a set of one or more acoustic sensors in communication therewith to capture fracture events below, above, and within the zone of interest. The system also include a second wellbore connected to the first wellbore at a lateral aperture in the first wellbore located above the acoustic assembly and containing a fracture treatment system, whereby the second wellbore and fracturing treatment system is hydraulically isolated from the second portion of the first wellbore containing the acoustic assembly. The system can further include an inductively coupled communication conduit bypass positioned within the first and the second portions of the first wellbore and extending from a location above the lateral aperture to a location below the lateral aperture to provide well operations in the second wellbore devoid of any acoustic monitoring equipment and associated interfering communication conduits.

[00029] A system according to another embodiment of the present invention can include a lower completion comprising wellbore sensors (e.g., acoustic sensors, etc.) positioned within a tubular, a lower umbilical extending from a position outside the tubular to a position adjacent an operable position of a first connector, a lateral wellbore positioned to avoid intersection with the lower umbilical and oriented at least partially lateral to an orientation of the tubular, and an upper completion run with an upper umbilical attached to the first connector. According to an exemplary configuration, the lower umbilical and tubular containing the wellbore sensors are configured to be run together. According to an exemplary configuration, the first connector connects to the upper umbilical. A second connector within a bore of the tubular connects to the wellbore sensors. An entranceway to the lateral wellbore is positioned at a location above the

second connector and below the first connector. According to an exemplary configuration, the first and the second connectors are configured to inductively couple to the lower umbilical.

[00030] According to an exemplary configuration, a packer is positioned below an entranceway to the lateral wellbore and above the plurality of acoustic sensors to minimize noise associated with movement of fracturing fluid through the lateral completion and encountered by the plurality of acoustic sensors and to isolate pressure encountered by the acoustic sensors. According to another exemplary configuration, the plurality of acoustic sensors are cemented in place to minimize noise encountered by the plurality of acoustic sensors and to isolate pressure.

[00031] A system according to another embodiment the present invention can include a lower completion comprising wellbore sensors (e.g., acoustic sensors, etc.) positioned within a tubular and positioned within a formation layer of interest, a lower umbilical extending from a position outside a portion of the tubular containing the well sensors to a position adjacent an operable position of a first connector, a lateral wellbore oriented at least partially lateral to an orientation of the tubular and positioned at least substantially within the formation layer of interest to thereby provide fracturing within the formation layer of interest. An upper completion run with an upper umbilical attached to the connector, whereby the connector operably coupled to the lower umbilical. According to an exemplary configuration, the connector is a first connector connecting to the upper umbilical, and the wellbore sensors are connected to at least portions of a second connector having at least portions positioned within a bore of the tubular. According to an exemplary configuration, the entranceway to the lateral wellbore is positioned at a location above the second connector and below the first connector.

[00032] According to an exemplary configuration, a lateral completion is horizontally aligned at least substantially between upper and lower boundaries of the formation layer of interest to provide fracturing within the formation layer of interest. According to such configuration, the portion of the tubular containing the acoustic sensors is positioned between upper and lower boundaries of the formation layer of interest. According to an exemplary configuration, a portion of the formation layer of interest is fractured above and below the lateral completion. According to such exemplary configuration, the acoustic sensors are positioned to receive fracturing data for portions of the formation layer of interest located above the lateral completion

and receive fracturing data from portions of the formation layer of interest located below the lateral completion.

[00033] Various embodiments of the present invention advantageously allow real time data transmission of seismic event data from the treatment well while pumping a hydraulic fracture treatment. Conventional practice is to drill an observation/monitoring well and to deploy geophones to monitor fracture seismic events during the fracture treatment or to deploy geophones at the surface. Often observation/monitoring wells or the surface is too far from the fracture treatment to allow collection of good quality monitoring data, and there substantial costs associated with establishing an observation/monitoring well. Accordingly, to solve such problems, various embodiments of the present invention advantageously provide for utilization of a single treatment well to perform fracture seismic mapping without a need for a separate monitoring well or surface equipment deployment. This can be accomplished by deploying the acoustic sensors downhole in a portion of the treatment well, below the sidetrack well used for delivering the fracturing fluid. This portion of the treatment well can be, for example, a portion of the pilot hole for the treatment well extending beyond the desired entrance location of the sidetrack well. Advantageously, use of, for example, the original pilot hole in a sidetrack provides a significant reduction in the cost of fracture wrapping by eliminating the drilling and completion of a separate monitoring well, which may typically cost $10.0 MM and 30-50 days of drilling rig time.

[00034] Various embodiments of the present invention also advantageously provide for isolating the acoustic sensors to provide for gathering acoustic data having an acceptable signal-to-noise ratio real-time during pumping, and/or provide for use of slurry concentrations greater than 4 PPA, by running the sensors below the kickover tool and/or installing a packer below the kickover tool to contain the acoustic sensors within the extended section of the main portion of the treatment well (e.g., the pilot hole)--separating the slurry carrying components and acoustic communications components so that they do not contact or otherwise communicate with each other. Advantageously, by placing the geophones below the kickover tool, the noise issue is reduced or eliminated with the use of simple filtering technology. Additionally, slurry limitations are eliminated, treating pressure is not limited to the tool deployed, and the geophones can be pre-positioned below, directly across the zone of interest and above the treatment interval.

[00035] Further, various embodiments of the present invention utilize an inductive coupler technology to provide for transmission of data to surface with real time measurements, which allows the acoustic sensors and acoustic receiver controller (e.g., seismic brain), to not only remain physically/hydraulically isolated, but also, electrically isolated--i.e., no electrical passageways or conduits providing communications between the acoustic receiver controller (e.g., seismic brain) and surface computer, need to be extended through the kickover tool or packer. The inductive coupler removes any physical contact between electrical connections and wellbore fluids. Power is transmitted through the coupler via an A/C current that creates an electromagnetic (EM) field transmitted to the female coupler. An additional advantage of this system is the positive power and communication provided across the coupling device.

[00035A] According to another embodiment of a method of determining hydraulic fracture geometry in a reservoir by combining functions of a first subterranean well and functions of a second subterranean well into a single well, the method comprises the steps of 1) running a lower completion comprising wellbore sensors positioned within a well casing, 2) running a communication conduit defining a lower umbilical, the lower umbilical extending from a position outside the well casing containing the well sensors, adjacent an operable position of a second connector, to a position adjacent an operable position of a first connector, 3) drilling a lateral wellbore, avoiding intersection with the lower umbilical, the lateral wellbore oriented at least partially lateral to an orientation of the well casing, and 4) running an upper completion with a communication conduit defining an upper umbilical, the upper umbilical operably connected to the first connector.

[00035B] According to another embodiment of a method of determining hydraulic fracture geometry in a reservoir by combining functions of a first subterranean well and functions of a second subterranean well into a single well, the method comprises the steps of 1) running a lower completion comprising wellbore sensors positioned within a well casing, the wellbore sensors positioned within a formation layer of interest, 2) running a communication conduit defining a lower umbilical, the lower umbilical extending from a position outside a portion of the well casing containing the well sensors to a position adjacent an operable position of a connector, 3) drilling a lateral wellbore, the lateral

wellbore oriented at least partially lateral to an orientation of the well casing and positioned at least substantially within the formation layer of interest to thereby provide fracturing within the formation layer of interest, and 4) running an upper completion with a communication conduit defining an upper umbilical, the upper umbilical attached to the connector, the connector operably coupled to the lower umbilical.

[00035C] According to another embodiment of a method of determining hydraulic fracture geometry of a zone of interest in a reservoir, the method comprises the steps of 1) providing a plurality of wells, each well comprising an upper completion, a lower completion, and a lateral completion extending into a lateral wellbore, 2) combining functions of a first subterranean well and functions of a second subterranean well into each separate one of the plurality of wells, by performing the following for each of the plurality of wells a) positioning a plurality of acoustic sensors in the lower completion, and b) hydraulically isolating the plurality of acoustic sensors from fracturing fluid flowing through the upper completion and the lateral completion, the isolation provided via an isolation device positioned below the lateral wellbore and above the plurality of acoustic sensors to minimize noise associated with movement of the fracturing fluid through the lateral completion and encountered by the plurality of acoustic sensors, and 3) sensing an acoustic event resulting from hydraulic fracturing associated with the lateral completion of one of the plurality of wells, the sensing performed by one or more of the plurality of acoustic sensors in at least two of the plurality of wells.

[00035D] According to another embodiment of a method of determining hydraulic fracture geometry of a zone of interest in a reservoir, the method comprises the steps of 1) positioning an acoustic assembly within a first wellbore adjacent the zone of interest in a reservoir, the first wellbore drilled within a portion of the reservoir to receive a hydraulic fracturing treatment defining the zone of interest, the acoustic assembly including an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events within the zone of interest, 2) inserting a drilling deflector into the first wellbore, 3) drilling a second wellbore to receive a fracturing fluid, 3) positioning a communication conduit bypass within the first wellbore to extend from a first location above an interface with the second wellbore to a second location below the interface with the second wellbore, 4) inductively coupling

the acoustic receiver controller to a first inductive coupler connected to a first end of the communication conduit bypass, the first inductive coupler positioned adjacent the second location below the lateral aperture, 5) inductively coupling surface equipment to a second inductive coupler connected to a second opposite end of the communication conduit bypass, the second inductive coupler positioned adjacent the first location above the lateral aperture, and 6) communicating real-time microseismic event data to a surface unit, the microseismic event data describing microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest through the second wellbore.

[00035E] According to another embodiment of a method of determining hydraulic fracture geometry of a zone of interest in a reservoir, the method comprises the steps of 1) positioning a kickover tool within a production liner in a first wellbore drilled within a portion of a reservoir to receive a hydraulic fracturing treatment defining a zone of interest, 2) positioning an acoustic assembly within the production liner in the first wellbore below major portions of the kickover tool and adjacent the zone of interest in the reservoir, the acoustic assembly including an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events within the zone of interest, 3) opening a lateral aperture in the production liner, the lateral aperture forming an entrance to a second wellbore to receive a fracturing fluid, 4) positioning a communication conduit bypass within the first wellbore to extend from a first location above the lateral aperture to a second location below the lateral aperture, 5) inductively coupling the acoustic receiver controller to a first inductive coupler connected to a first end of the communication conduit bypass, the first inductive coupler positioned adjacent the second location below the lateral aperture, 6) inductively coupling surface equipment to a second inductive coupler connected to a second opposite end of the communication conduit bypass, the second inductive coupler positioned adjacent the first location above the lateral aperture, and 7) communicating real-time microseismic event data to a surface unit, the microseismic event data describing microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest.

[00036] Various embodiments of the present invention further advantageously provide for the use of a total pressure necessary for optimal fracturing, without concern for the pressure limitations of electric line cable heads providing communications between an acoustic assembly and a surface unit, and/or provide for employment of a monitoring system within the treatment well that does not impede current or future sidetracking operations. By employing the inductive coupling technology, electrical telemetry is transferred from inside the well to external of the production liner at a location above an anticipated or existing aperture in the production liner by a first inductive coupling and is returned to be inside the well and at location below the anticipated or existing location of the kickover tool by a second inductive coupling, with the cabling between the two couplings routed external to the production liner away from the location of the anticipated or existing aperture in the production liner.

BRIEF DESCRIPTION OF THE DRAWINGS

[00037] So that the manner in which the features and advantages of the invention, as well as others which will become apparent, may be understood in more detail, a more particular description of the invention briefly summarized above may be had by reference to the embodiments thereof which are illustrated in the appended drawings, which form a part of this specification. It is to be noted, however, that the drawings illustrate only various embodiments of the invention and are therefore not to be considered limiting of the invention's scope as it may include other effective embodiments as well.

[00038] FIG. 1 is a schematic diagram of a general system architecture of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest within a reservoir according to an embodiment of the present invention;

[00039] FIG. 2 is a schematic diagram of the downhole portion of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest within a reservoir according to an embodiment of the present invention;

[00040] FIGS. 3-11 provide a series of schematic diagrams illustrating the development of a main wellbore, a wellbore for performing fracturing operations, and deployment of the downhole portion of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest within a reservoir according to embodiments of the present invention;

[00041] FIG. 12 is a schematic diagram illustrating operational employment of downhole portions of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest within a reservoir according to an embodiment of the present invention;

[00042] FIG. 13 is a schematic diagram of an inductive circuit according to an embodiment of the present invention;

[00043] FIG. 14 is a schematic diagram illustrating duplicate portions of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest employed in a pair of adjacent producing wells, commonly receiving, processing, and providing complementary data for each other according to an embodiment of the present invention;

[00044] FIG. 15 is a schematic diagram illustrating a plurality of taps in a primary umbilical cord illustrating use of the umbilical cord as a primary communications link between both downhole acoustic sensors and reservoir monitoring sensors according to an embodiment of the present invention;

[00045] FIG. 16 is a schematic diagram illustrating application of a plurality of flow control devices according to an embodiment of the present invention; and

[00046] FIG. 17 is a schematic diagram illustrating a communication line connection configuration between surface components and downhole acoustic sensors according to an embodiment of the present invention.

DETAILED DESCRIPTION

[00047] The present invention will now be described more fully hereinafter with reference to the accompanying drawings, which illustrate embodiments of the invention. This invention may, however, be embodied in many different forms and should not be construed as limited to the illustrated embodiments set forth herein. Rather, these embodiments are provided so that this disclosure will be thorough and complete, and will fully convey the scope of the invention to those skilled in the art. Like numbers refer to like elements throughout. Prime notation, if used, indicates similar elements in alternative embodiments.

[00048] Various embodiments of the present invention advantageously provide systems and methods for real-time monitoring of hydraulic fractures using the treatment well pilot hole. According to an exemplary embodiment of the present invention, the well is drilled through the desired formation where the fracture treatment will take place. A kickover or other deflecting tool is then lowered into the wellbore and oriented to the preferred fractured orientation. Below the kick-over tool are acoustical sensors. At least one sensor is run, but preferably a series of sensors are run below the kickover tool. With the kickover tool in place, a sidetrack is drilled either as a vertical or horizontal wellbore. Advantageously, multiple sidetracks can be placed if required by stacking the kickover tools. Noise while pumping the fracturing fluid will be further minimized by placing a packer located below the kickover tool. The following provides additional details according to an exemplary embodiments of the present invention.

[00049] As shown in FIG. 1, a system 30 to determine hydraulic fracture geometry and areal extent of an area of interest 21 of a reservoir 23 can include a fracture mapping computer 31 having a processor 33, memory 35 coupled to the processor 33 to store software and database records therein, and a user interface 37 which can include a graphical display 39 for displaying graphical images, and a user input device 41 as known to those skilled in the art, to provide a user access to manipulate the software and database records. Note, the computer 31 can be in the form of a personal computer or in the form of a server or server farm serving multiple user interfaces 37 or other configuration known to those skilled in the art. Accordingly, the user interface 37 can be either directly connected to the computer 31 or through a network 38 as known to those skilled in the art.

[00050] The system 30 can also include a database (not shown) stored in the memory 35 (internal or external) of the fracture mapping computer 31 and having data indicating position points of detected seismic events, and can include fracture mapping program product 51 stored in memory 35 of the fracture mapping computer 31 and adapted to receive signals from an acoustic receiver controller 61. Note, the fracture mapping program product 51 can be in the form of microcode, programs, routines, and symbolic languages that provide a specific set for sets of ordered operations that control the functioning of the hardware and direct its operation, as known and understood by those skilled in the art. Note also, the fracture mapping program product 51, according to an embodiment of the present invention, need not reside in its entirety in volatile memory, but can be selectively loaded, as necessary, according to various methodologies as known and understood by those skilled in the art. Still further, at least portions of the fracture mapping program product 51 can be stored in memory of the acoustic receiver controller 61 and/or executed by acoustic receiver controller 61.

[00051] As shown in FIGS. 1 and 2, the system 30 also includes an acoustic assembly 63 including the acoustic receiver controller (e.g., seismic brain) 61 and a set of at least one, but more typically a plurality of acoustic sensors (e.g., geophones, hydrophones, etc.) 65 hung below a kickover or other drilling deflection-type tool 71 positioned within a production or other liner 73, itself hung within a casing 75 itself positioned within a main portion 77 of a typically vertical wellbore 78. In a cased hole configuration, liner 73 is hung within casing 75 using a casing hangar 74 or other means as understood by one of ordinary skill in the art.

[00052] According to the illustrated embodiment of the system 30, the set of acoustic sensors 65 include multiple spaced apart sensors spaced at a predetermined distance or distances capture the same set of fracturing events, but at different travel times, to allow for triangulation of the received acoustic signals emanating from each separate fracture event. Note, as shown in FIG. 2, a packer or packers 79, 84 as known and understood by those of ordinary skill in the art can optionally be installed within the bore 76 of the production liner 73 prior to the installation of kickover tool 71. According to one embodiment, the packer 79 is positioned below the kickover tool 71 at a location above the acoustic assembly 63 to isolate the sensors 65 from acoustic interference. In such embodiment, a centralizer (not shown) or other connection device can be used to stabilize the sensors 65 within the bore 76 of the liner 73. According to an alternative embodiment, the packer 84 as installed below the acoustic assembly 63 to hydraulically seal

chamber 80 within liner 73 to contain the acoustic assembly 63, and in conjunction with the kickover tool 71 (or other whipstock-type tool) and/or another packer 79 adjacent thereto, to thereby prevent hydraulic incursions.

[00053] According to the illustrated embodiment of the system 30, wellbore 78 includes the main or "upper formation" portion 77 and a "lower formation" portion 81 primarily comprising the pilot hole 82 drilled to guide drilling of the main portion 77 of the wellbore 78. As shown in the figures, according to such configuration, the acoustic assembly 63 and at least portions of the kickover tool 71 are landed within the lower portion 81 of the wellbore 78 (e.g., within chamber 80), and/or physically connected to hang from the kickover tool 71.

[00054] A locator key 83 comprising a recess-protuberance combination, illustrated as a recess 85 in the liner 73 and an annular protuberance 87 or set of one or more individual protuberances extending radially from the lower portion of the kickover tool 71, can be utilized to properly orient the kickover tool 71 and/or the set of acoustic sensors 65. Note, other means including a protuberance-recess combination or utilization of a centralizer (not shown) supporting or landing the set of acoustic sensors 65 and/or the kickover tool 71, or other means known to one of ordinary skill in the art, however, is/are within the scope of the present invention.

[00055] According to the illustrated embodiment of the system 30, the kickover tool 71 includes a recess 89 containing at least portions of the acoustic receiver controller 61 or associated connection hardware (not shown) as understood by one of ordinary skill in the art. The kickover tool 71 also includes an annular recess 91 housing a male inductive coupler 93 (individual or assembly) connected to an electrical conduit 95 connected to or otherwise in communication with the acoustic receiver controller 61. Note, the locator key 83 provides both positioning of the kickover tool 71 and positioning of the male inductive coupler 93. Note also, as described is being electrical conduit, conduit 91 can take other forms including optical, RF, etc. or combination thereof.

[00056] Further, according to the illustrated embodiments of the system 30, the liner 73 is landed within a lower end of the casing 75, preferably at least partially within a portion 97 of the wellbore 78 extended out, for example, by an "undee" ream bit (not shown), using means as known and understood by one of ordinary skill in the art. According to a preferred configuration, the external surface 99 of the liner 73 carries a set of female inductive couplers

101, 102 connected via a communication conduit, e.g., electrical cable 103 routed along the external surface 99 of the liner 73, above and below a radial aperture 105, respectively. The radial aperture 105 is pre-formed prior to landing of the liner 73 or later cut through the exterior wall 99 of the liner 73 to provide a pathway for a "sidekick" drilled as a horizontal or vertical wellbore (e.g., lateral wellbore 109) carrying the various fracturing equipment 111. As such, beneficially, the female inductive couplers 101, 102 and the cable 103 do not impede fracturing operations or formation of the lateral wellbore 109.

[00057] The system 30 also includes a string of tubing 121 extending from a surface 123 (FIG. 1), through the main portion 77 of the wellbore 78 and casing 75, through the bore of liner 73 above aperture 105, through aperture 105, and into wellbore 109. The portion 125 of the tubing string 121 contained within wellbore 109 can include the various fracturing equipment 111 including multiple sets of perforations 127 to pass fracturing fluid into the reservoir 23, and can include multiple fracturing valves 129 to control fluid (e.g. slurry) delivery within each set of perforations 127, to thereby provide for multi-stage fracturing.

[00058] A portion 131 of the tubing string 121 located above the aperture 105 can house or otherwise carry a male inductive coupler 133 on its exterior surface 99. The male inductive coupler 133 is sized to be deployed within the inner diameter 137 of liner 73. When properly deployed with portion 131 of tubing string 121, male inductive coupler 133 is positioned to complement the female inductive coupler 101 connected to the exterior surface 99 of liner 73. Correspondingly, the portion 131 can include a tubing locator 141 sized to extend through casing 75 and to land upon an upper portion 143 of the casing hangar 74 hanging liner 73 (defining a landing point or surface 143). The male inductive coupler 133 is spaced apart at a predetermined longitudinal distance from the tubing locator 141 so that when the tubing locator 141 is landed upon landing point/surface 143, the male inductive coupler 133 is in a proper juxtaposition with female inductive coupler 101. The locator key 83, described previously, locates the male inductive coupler 93 in the proper juxtaposition with female inductive coupler 102, to thereby form a properly matched inductive circuit 145 (see, e.g., FIG. 13).

[00059] A communication conduit, e.g. electrical cable 147 is physically connected to outer surface portions of the exterior surface 135 of the tubing string 121 and electrically connected to male inductive coupler 133, e.g., via a wet connector, to provide data to computer 31.

Beneficially, the electrical and physical isolations can be achieved by using inductive coupler pairs 101, 133, and 102, 93, to connect the surface equipment (e.g., computer 31) with the downhole acoustic monitoring assembly 63. Note, although described as being electrical conductors, it should be understood that conduits/cables 103, 147 can take various forms including electrical, optical, electro-optical, wireless, hydraulic or a combination thereof and are often collectively referred to as umbilicals. Note also, as shown in FIG. 17, although illustrated in the form of an inductive coupling, conduit/cable 103 can be hard-line connected to the acoustic assembly 63 via a connection with/through kickover tool 71' and can be connected to conduit/cable 147 via connector 133' illustrated as being positioned adjacent landing point 143.

[00060] FIGS. 1 and 2 illustrate a "cased hole" configuration of the wellbores 78, 109. One of ordinary skill in the art, however, would recognize that one or more embodiments of the present invention fall within the scope of the system 30 employed in non-cased wellbores. Additionally, in the exemplary illustration, the casing 75 is 9 5/8 inch casing, the tubing liner is 7 inch, and the tubing string 121 is 4 1/2 tubing, and the lateral wellbore 109 is 6 1/8 inch. Various other sizes as known to those of ordinary skill in the art, however, are within the scope of the present invention.

[00061] FIGS. 3-12 illustrate examples of embodiments of a method of determining hydraulic fracture geometry and areal extent of an area/zone of interest 21 in a reservoir 23 by combining functions of a subterranean observation well and a subterranean producing well into a single producing well 53. Referring to FIG. 3, according to an example of an embodiment of the method, a wellbore 78 is drilled through the area/zone of interest 21 and is either cased and cemented or left in an openhole state. According to the illustrated method, a pilot hole 82 is first drilled followed by the main portion 77.

[00062] As illustrated in FIG. 3, an undee reaming bit (not shown) can be used to widen the portion of the wellbore 78 at a location where a sidekick (e.g., wellbore 109, FIG. 2) is to be drilled. As shown in FIG. 4, in the illustrated cased-hole configuration, casing 75 is run within the upper portion 77 of the wellbore 78 above the undee 97.

[00063] As illustrated in FIG. 5, liner 73 is hung within casing 75 using a casing hangar 74 or other means as understood by one of ordinary skill in the art. According to the illustrated configuration, liner 73 extends from above undee 97, through undee 97, and through significant

portions of the pilot hole 82 preferably having an inner diameter similar to that of the liner 73. As further illustrated in FIG. 5, liner 73 includes female inductive couplers 101, 102, connected to or embedded within an outer/exterior surface 99.

[00064] As illustrated in FIGS. 6 and 7, in order to acoustically isolate the set of acoustic sensors 65, a packer 79 can be positioned at a location below the kickover tool or other deflection-type tool 71 but above at least the acoustic sensors 65. In order to acoustically isolate further hydraulically isolate acoustic assembly 63, a packer 84 can also or alternatively be inserted within the bore 76 of the liner 73 at a location below the lowest (most downhole) expected point of the acoustic assembly 63.

[00065] As illustrated in FIG. 7, regardless of whether or not packer 79 is run, the method includes running a kickover or other deflection-type tool 71 to isolate the acoustic assembly 63 from the fracturing operations, described below. According to an exemplary configuration, the kickover tool 71 is deployed with geophones or other acoustic receivers 65 hung below at predetermined intervals to capture fracture events below, above and within the area/zone of interest 21. The geophones or other acoustic receivers 65 can be coupled to the inner surface of the tubing liner 73 or alternatively, directly to the open hole section of the pilot hole 82. Coupling of the geophones or other acoustic receivers 65 can be accomplished by cementing them in place in either the open hole or cased hole or hanging the geophones or other acoustic receivers 65 in the cased hole or the open hole using centralizers (not shown). Note, if left un-cemented, the kickover tool 71 and acoustic receivers 65 can be retrieved at a later date.

[00066] As illustrated in FIG. 8, according to another configuration, the casing 75, liner 73, kick over tool 71', packer 79, acoustic assembly 63, upper and lower communication conduits 103, 147, and the upper inductive coupler 101 can be run together. Although inductive coupler pair 102, 93 can also be run, according to such configuration, as shown in the figure, conduit 103 can instead be hardwired to acoustic controller 61 through passageway 72. FIG. 9 illustrates an embodiment whereby the acoustic sensors 65 of the acoustic assembly 63 are instead cemented to reduce noise and/or isolate pressure that would otherwise be encountered by the acoustic sensors 65.

[00067] Regardless of the running methodology, as illustrated in FIG. 10, having the kickover tool 71 positioned within liner 73 (or directly within the pilot hole 82 if no liner 73 was utilized), wellbore 109 is drilled through aperture 105 at a desired length and distance and depth.

[00068] As illustrated in FIG. 11, a tubing string 121 is run from surface 123 (FIG. 1), through the casing 75, through the bore of liner 73 above aperture 105, through aperture 105, and into wellbore 109. The portion 125 of the tubing string 121 contained within wellbore 109 can include the various fracturing equipment 111 including multiple sets of perforations 127 to pass fracturing fluid into the reservoir 23, and fracturing valves 129 to control fluid (e.g. slurry) delivery within each set of perforations 127. The portion 131 of the tubing string 121 located above the aperture 105 can house or otherwise carry the male inductive coupler 133 on its exterior surface 135. In order to place male inductive coupler 133 in a proper juxtaposition with female inductive coupler 101, the deployment of tubing string 121 includes landing a tubing locator 141 in contact with a landing point/surface 143.

[00069] As illustrated in FIG. 12, during pumping operations, microfractures begin generating acoustic signals which are received at different times by the separated acoustic receivers 65. As illustrated in FIG. 13, in the illustrated embodiment whereby communications are established between the surface 123 (e.g., computer 31) and the acoustic sensors 65 utilizing inductive coupling, an inductive circuit is formed as illustrated, which can provide a reliable means to make an electrical connection down hole in well test operations. Processed acoustic data, processed by acoustic controller 61, is transmitted uphole via the illustrated circuit through the illustrated series of conductor connections and inductive couplings.

[00070] Beneficially, the utilization of the inductive coupling, particularly in conjunction with the establishment of separate electrical connections which do not across boundaries, can function to remove any physical contact between electrical connections and wellbore fluids. An advantage of this system/process is the positive communication provided across the coupling devices. The inductive couplings function so that communication signals emanating from acoustic controller 61 are transmitted through an A/C current created in male coupler 93, which creates an electromagnetic (EM) field transmitted to the female the coupler 102.

[00071] Similarly, FIG. 14 illustrates acoustic sensors 65 receiving acoustic signals from microfracture sources resulting from fracturing operations adjacent separate lateral wellbores

109, 109'. In this embodiment, however, the other lateral wellbore 109' is associated with an adjacent producing well 53'. Further, data from the respective acoustic controllers 61 associated with each respective producing well 53, 53' can be gathered by computer 31 via network 38 and compared. Alternatively, each producing well 53, 53' can have a separate computer 31 associated therewith in communication with each other through network 38 and/or another network as known to one of ordinary skill in the art.

[00072] According to another embodiment of the present invention, the system/process also includes an advantage whereby power can be delivered across the coupling devices to provide power to the acoustic assembly 63. In yet another embodiment of the present invention, an additional coupling can be made with inductive coupler 133, inductive coupler 101, and/or a Tee-type connection 151 or other form of tap or series of taps in cable 147 (FIG. 15) to provide power and/or communications to the fracturing equipment 111 from the surface 123 and/or provide support to reservoir monitoring sensors 128 such as, for example, pressure, temperature, flow, DTS sensors, etc.. According to an embodiment, a plurality of reservoir monitoring sensors 128 can provide various reservoir condition sensing functions to include providing or providing for determining conductivity for waterfront observation, along with others known to those of ordinary skill in the art.

[00073] FIG. 16 illustrates another embodiment of the present invention whereby improved production control is achieved through application of one or more flow management components 153 such as, for example, inflow control valves, inflow control devices, and/or isolation packers.

[00074] This application claims priority to U.S. Non-Provisional Patent Application number 13/269,596 titled "Method for Real-Time Monitoring and Transmitting Hydraulic Fracture Seismic Events to Surface using the Pilot Hole of the Treatment Well as the Monitoring Well", filed October 9, 2011, and is related to U.S. Non-Provisional Patent Application Number 13/269,599, titled "System For Real-Time Monitoring and Transmitting Hydraulic Fracture Seismic Events To Surface Using The Pilot Hole Of The Treatment Well As the Monitoring Well," filed on October 9, 2011, which may be referred to for further details.

[00075] In the drawings and specification, there have been disclosed a typical preferred embodiment of the invention, and although specific terms are employed, the terms are used in a descriptive sense only and not for purposes of limitation. The invention has been described in

considerable detail with specific reference to these illustrated embodiments. It will be apparent, however, that various modifications and changes can be made within the spirit and scope of the invention as described in the foregoing specification. For example, in place of the inductive coupling portions of inductive coupling circuit 145, connectors such as, e.g., wet mate connectors can be employed as a substitute for the sets of inductive coupling, albeit with some degradation to the advantages of the above described embodiments of the featured system that employ inductive coupling.

What is claimed is:

1. A method of determining hydraulic fracture geometry of a zone of interest in a reservoir, the method comprising the steps of:

positioning an acoustic assembly within a first wellbore adjacent the zone of interest in a reservoir, the first wellbore drilled within a portion of the reservoir to receive a hydraulic fracturing treatment defining the zone of interest, the acoustic assembly including an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events within the zone of interest;

inserting a drilling deflector into the first wellbore, wherein the set of one or more acoustic sensors are connected to a down-hole facing portion of the drilling deflector prior to the drilling deflector being inserted to the first wellbore;

drilling a second wellbore to receive a fracturing fluid;

positioning a communication conduit bypass within the first wellbore to extend from a first location above an interface with the second wellbore to a second location below the interface with the second wellbore;

inductively coupling the acoustic receiver controller to a first inductive coupler connected to a first end of the communication conduit bypass, the first inductive coupler positioned adjacent the second location below the lateral aperture;

inductively coupling surface equipment to a second inductive coupler connected to a second opposite end of the communication conduit bypass, the second inductive coupler positioned adjacent the first location above the lateral aperture;

isolating the set of one or more acoustic sensors from acoustic interference associated with delivery of fracturing fluid through a conduit string extending through portions of the first wellbore and into the second wellbore when performing the hydraulic fracturing of the reservoir in the zone of interest to thereby minimize noise encountered by the set of one or more acoustic sensors and associated with movement of fracturing fluid, the isolating comprising positioning a packer within a production liner containing the one or more acoustic sensors below major portions of the first wellbore containing the conduit string and above the set of one or more acoustic sensors to thereby minimize the noise encountered by the set of one or more acoustic sensors and associated with movement of the fracturing fluid; and

detecting microseismic events associated with the performance of the hydraulic fracturing, the step of detecting including employing the set of one or more acoustic sensors; and

communicating real-time microseismic event data to a surface unit, the microseismic event data describing the microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest through the second wellbore.

2. The method as defined in claim **1**, wherein the step of positioning a communication conduit bypass within the first wellbore includes the steps of:

determining an expected location of the lateral aperture through a production liner;

connecting the second inductive coupler to an outer facing surface of the production liner at a location above the expected location of the lateral aperture;

connecting first inductive coupler to an outer facing surface of the production liner at a location below the expected location of the lateral aperture;

connecting an electrical conduit along an outer surface of the production liner between the first and the second inductive couplers away from the expected location of the lateral aperture; and

running the production liner within the first wellbore.

3. The method as defined in claim **2**, wherein the steps of inductively coupling the acoustic receiver controller to the first inductive coupler and inductively coupling surface equipment to the second inductive coupler comprises the steps of:

connecting a third inductive coupler to an outward facing surface of a portion of a tubing segment at a predetermined longitudinal distance from a reference point associated with a tubing locator extending from an outer surface portion of the tubing segment, the predetermined longitudinal distance coinciding with a longitudinal distance from the reference point to the second inductive coupler when the tubing locator is landed upon a portion of the production liner; and

connecting a fourth inductive coupler to an outward facing surface of the drilling deflector at a predetermined longitudinal distance from a reference point associated therewith, the predetermined longitudinal distance coinciding with a longitudinal distance from the drilling

deflector reference point to the first inductive coupler when the drilling deflector is landed at a preselected location within the production liner.

4. The method as defined in claim **1**, wherein the second wellbore is devoid of any acoustic monitoring equipment and associated interfering communication conduits.

5. A method of determining hydraulic fracture geometry of a zone of interest in a reservoir, the method comprising the steps of:

positioning a kickover tool within a production liner in a first wellbore drilled within a portion of a reservoir to receive a hydraulic fracturing treatment defining a zone of interest;

positioning an acoustic assembly within the production liner in the first wellbore below major portions of the kickover tool and adjacent the zone of interest in the reservoir, the acoustic assembly including an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events within the zone of interest;

opening a lateral aperture in the production liner, the lateral aperture forming an entrance to a second wellbore to receive a fracturing fluid;

positioning a communication conduit bypass within the first wellbore to extend from a first location above the lateral aperture to a second location below the lateral aperture;

inductively coupling the acoustic receiver controller to a first inductive coupler connected to a first end of the communication conduit bypass, the first inductive coupler positioned adjacent the second location below the lateral aperture;

inductively coupling surface equipment to a second inductive coupler connected to a second opposite end of the communication conduit bypass, the second inductive coupler positioned adjacent the first location above the lateral aperture; and

communicating real-time microseismic event data to a surface unit, the microseismic event data describing microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest.

6. The method as defined in claim **5**, further comprising the steps of:

isolating the set of one or more acoustic sensors from acoustic interference associated with delivery of fracturing fluid through a conduit string extending through portions of the first

wellbore and into the second wellbore when performing the hydraulic fracturing of the reservoir in the zone of interest to thereby minimize noise encountered by the set of one or more acoustic sensors and associated with movement of fracturing fluid; and

detecting microseismic events associated with the performance of the hydraulic fracturing, the step of detecting including employing the set of acoustic sensors.

7. The method as defined in claim **6**, wherein the step of isolating the set of one or more acoustic sensors from acoustic interference includes the step of:

positioning a packer within the production liner below major portions of the kickover tool and above the set of one or more acoustic sensors to thereby minimize the noise encountered by the set of one or more acoustic sensors and associated with movement of the fracturing fluid.

8. The method as defined in claim **5**, wherein the steps of positioning a kickover tool within a production liner and positioning an acoustic assembly within the production liner are performed simultaneously, the method further comprising the step of:

connecting the set of one or more acoustic receivers to a down-hole facing portion of the kickover tool prior to performing the step of positioning the kickover tool in the production liner.

9. The method as defined in claim **5**, wherein the step of positioning a communication conduit bypass within the first wellbore includes the steps of:

determining an expected location of the lateral aperture through the production liner;

connecting the second inductive coupler to an outer facing surface of the production liner at a location above the expected location of the lateral aperture;

connecting first inductive coupler to an outer facing surface of the production liner at a location below the expected location of the lateral aperture;

connecting an electrical conduit along an outer surface of the production liner between the first and the second inductive couplers away from the expected location of the lateral aperture; and

running the production liner within the first wellbore.

10. The method as defined in claim **9**, wherein the steps of inductively coupling the acoustic receiver controller to the first inductive coupler and inductively coupling surface equipment to the second inductive coupler comprises the steps of:

connecting a third inductive coupler to an outward facing surface of a portion of a tubing segment at a predetermined longitudinal distance from a reference point associated with a tubing locator extending from an outer surface portion of the tubing segment, the predetermined longitudinal distance coinciding with a longitudinal distance from the reference point to the second inductive coupler when the tubing locator is landed upon a portion of the production liner; and

connecting a fourth inductive coupler to an outward facing surface of the kickover tool at a predetermined longitudinal distance from a reference point associated therewith, the predetermined longitudinal distance coinciding with a longitudinal distance from the kickover tool reference point to the first inductive coupler when the kickover tool is landed at a preselected location within the production liner.

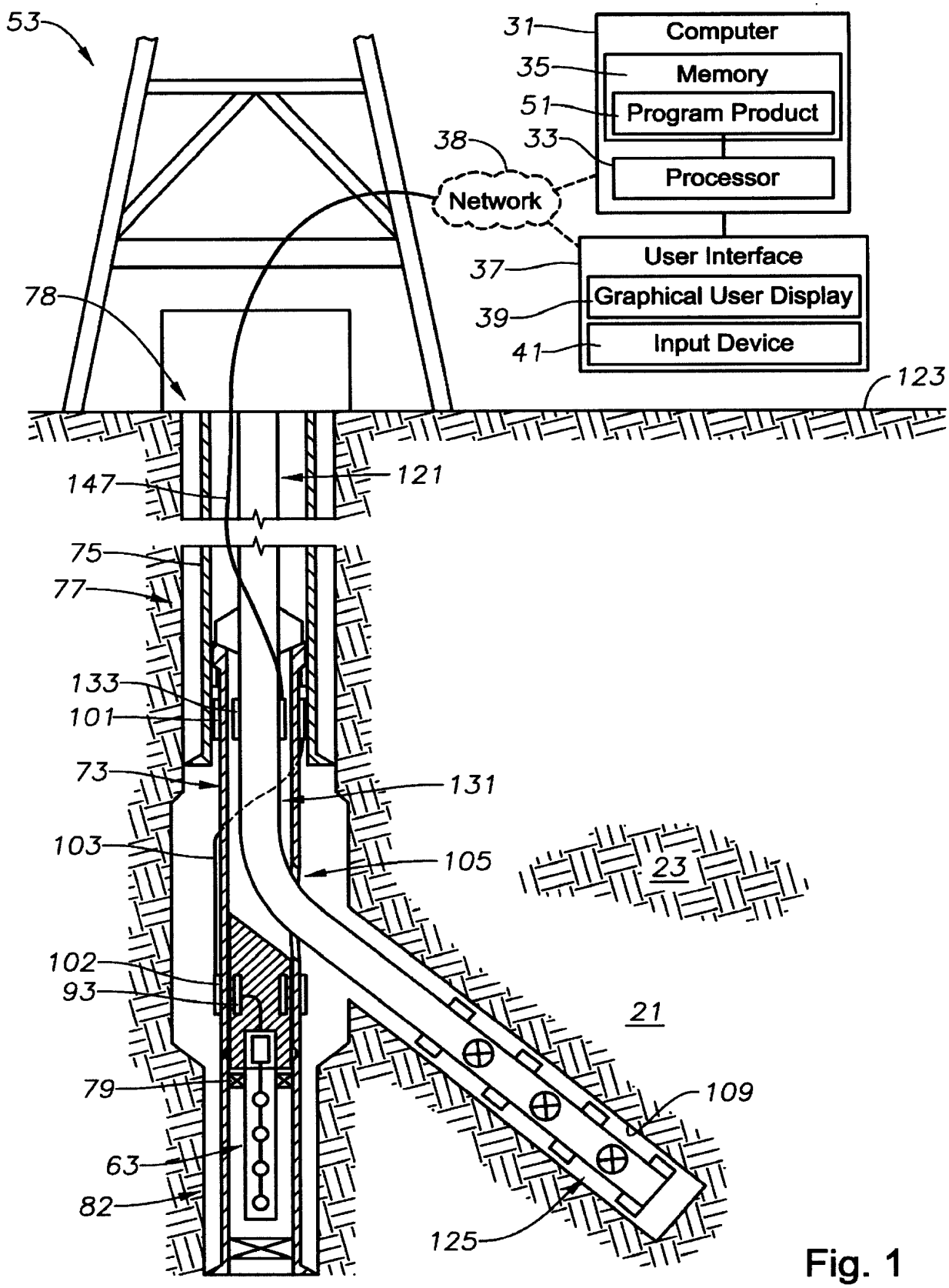

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Fig. 1

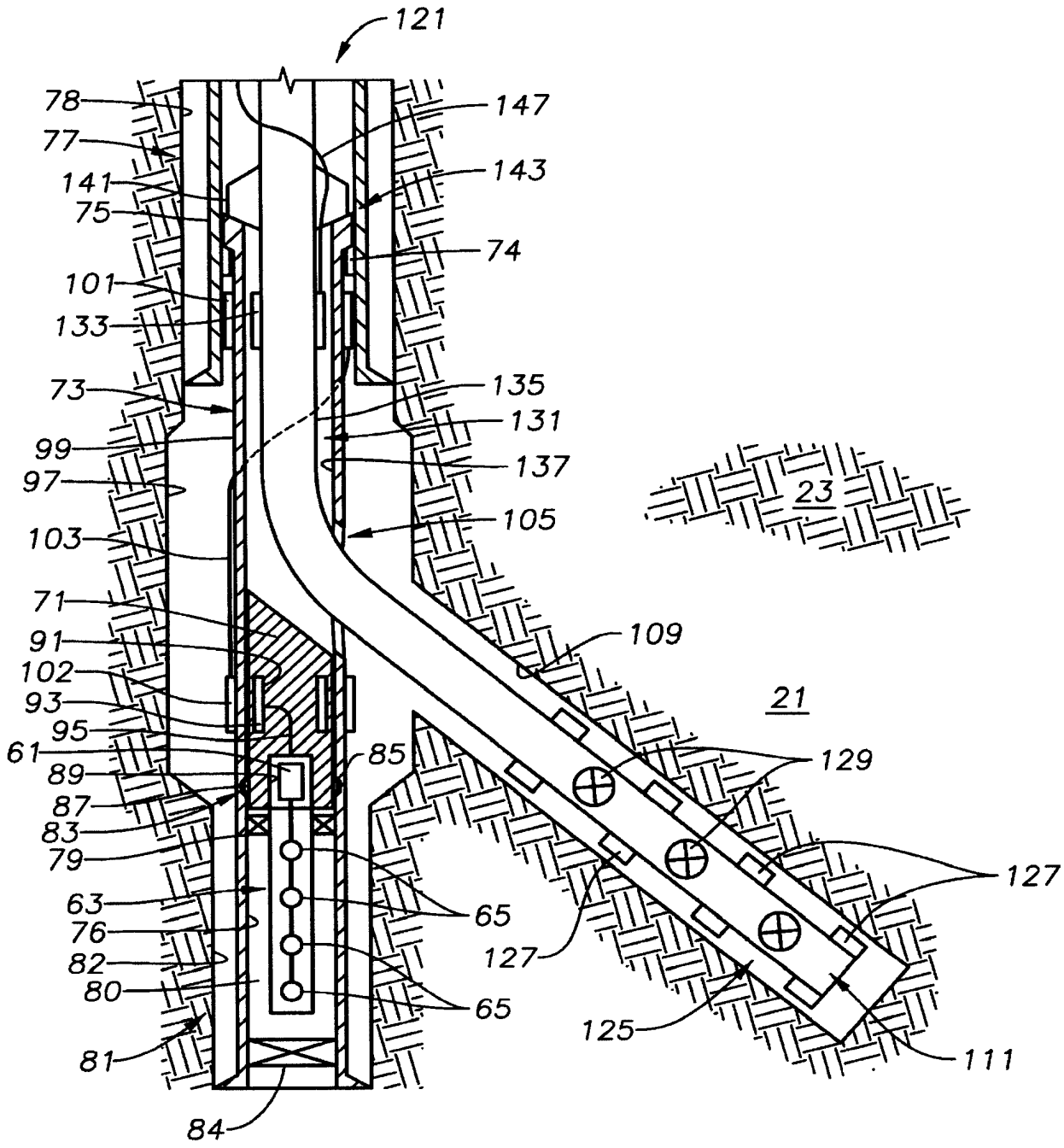

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Fig. 2

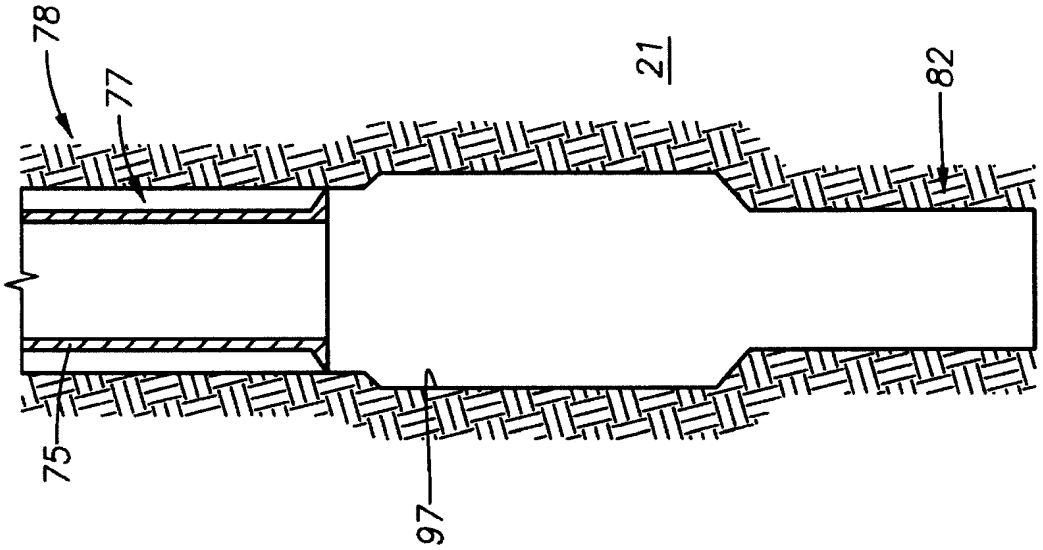


Fig. 4

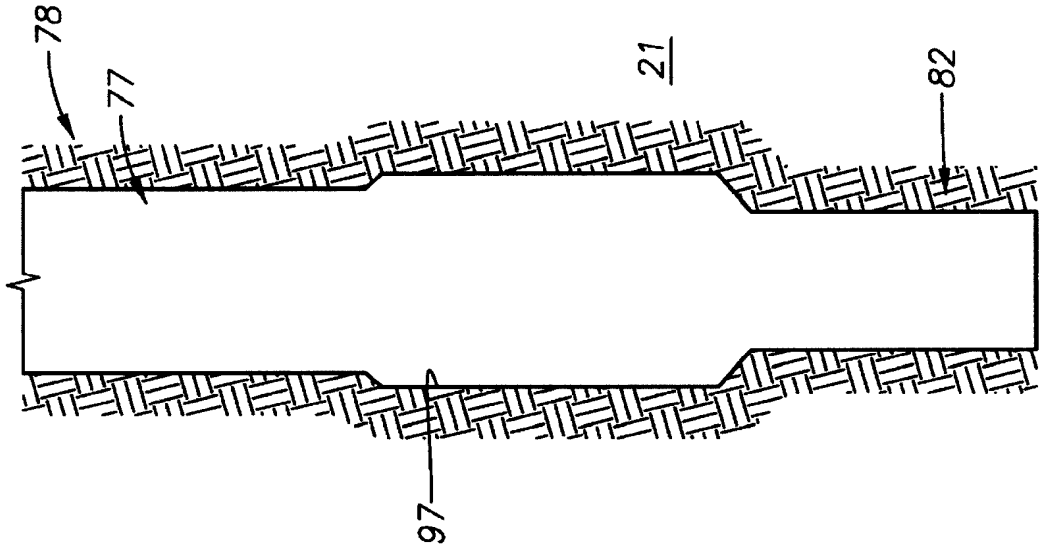


Fig. 3

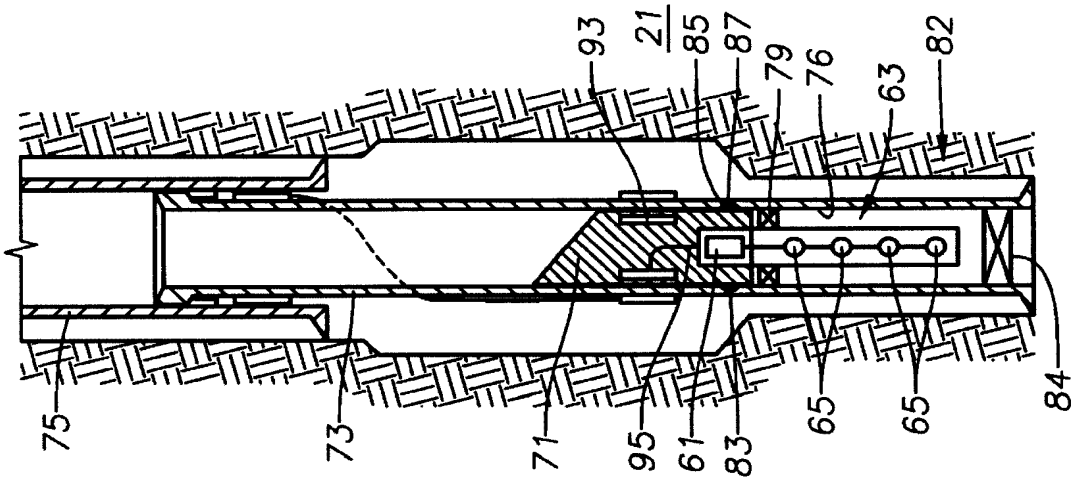


Fig. 7

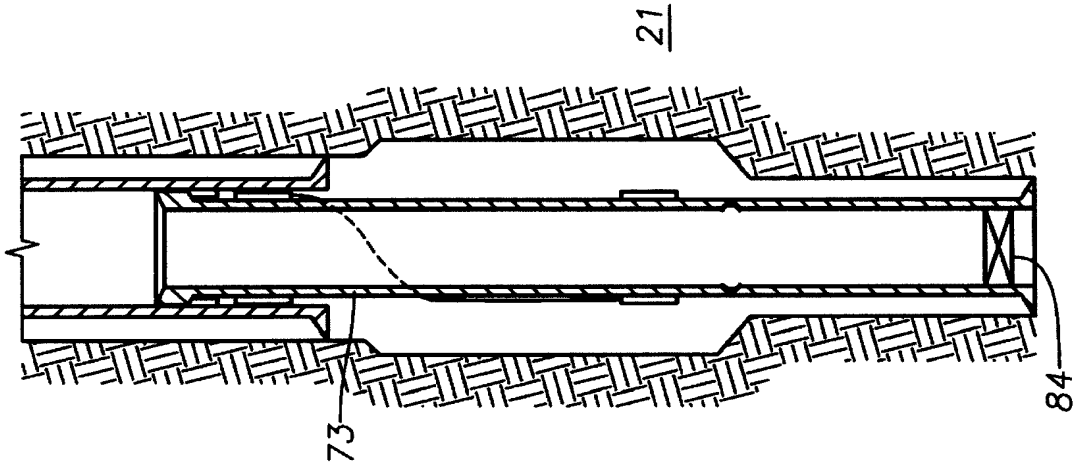


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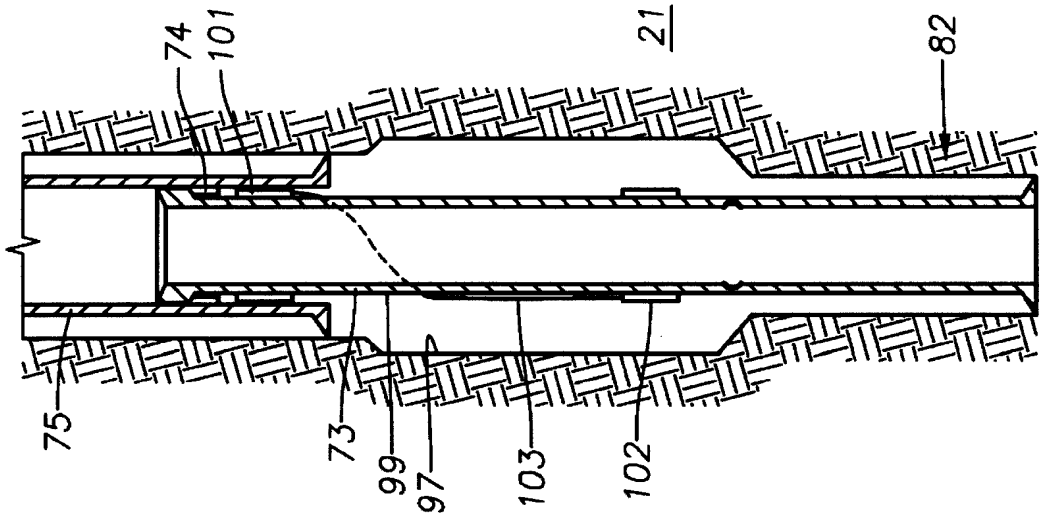


Fig. 5

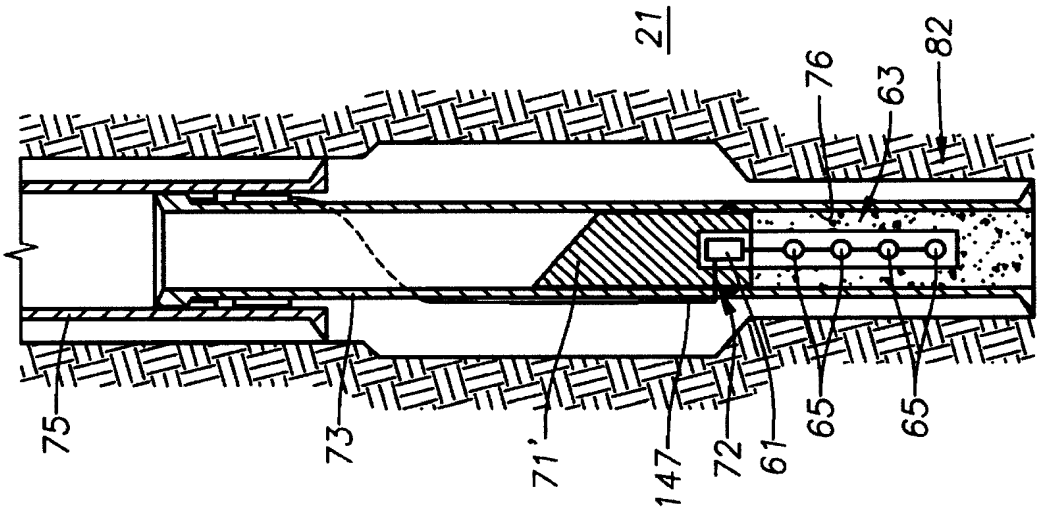

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Fig. 9

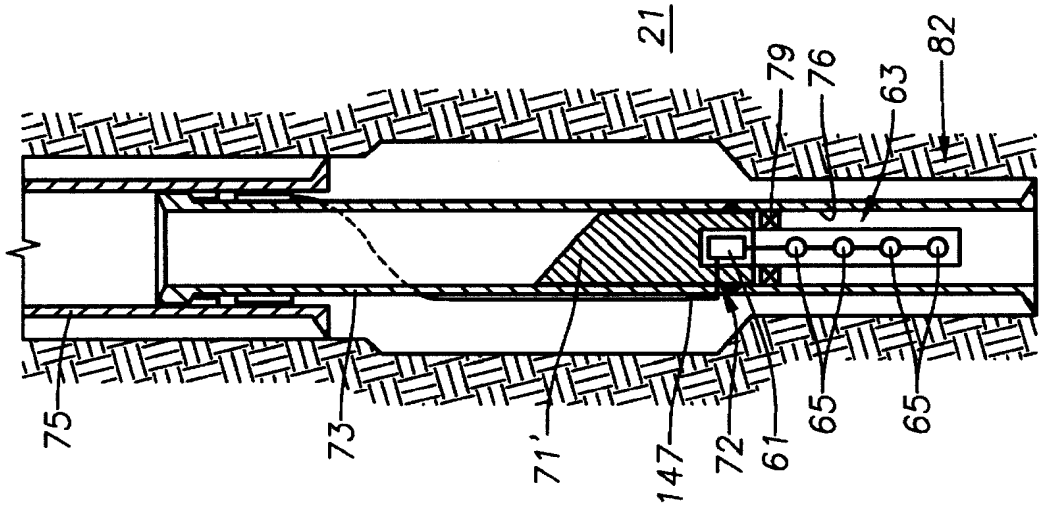

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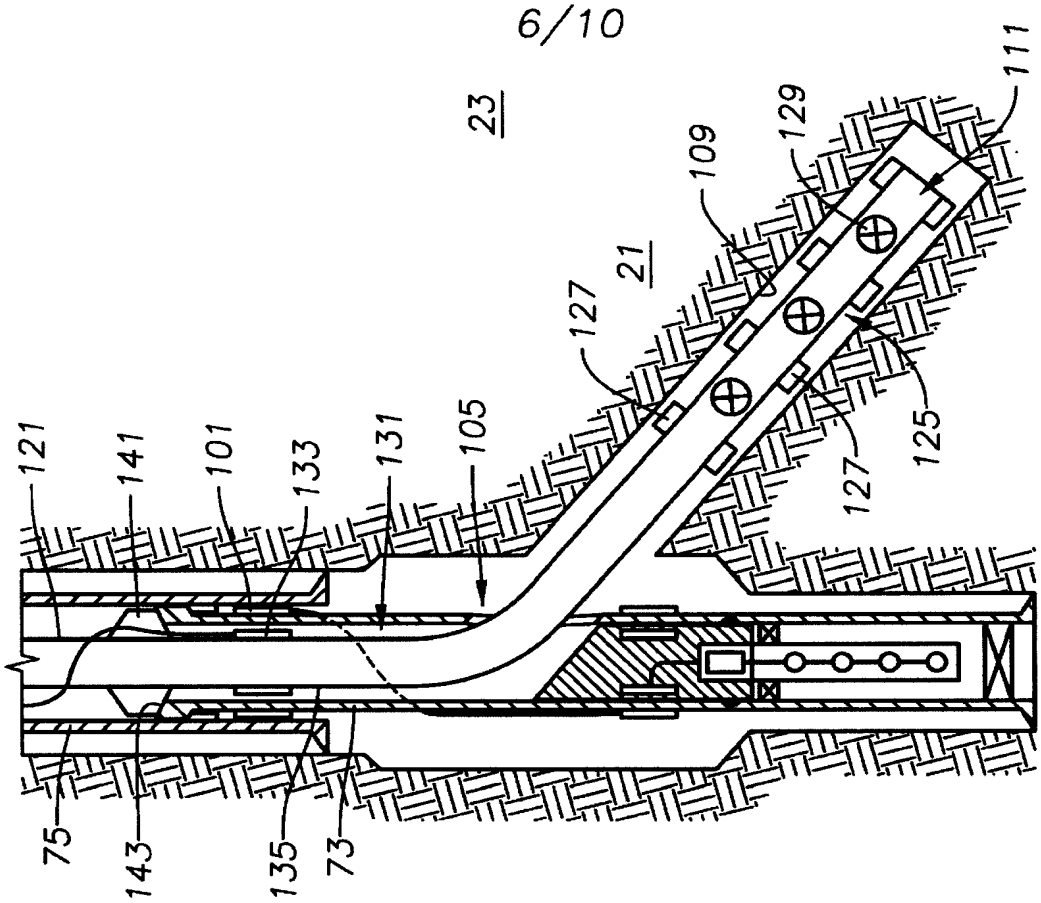

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Fig. 11

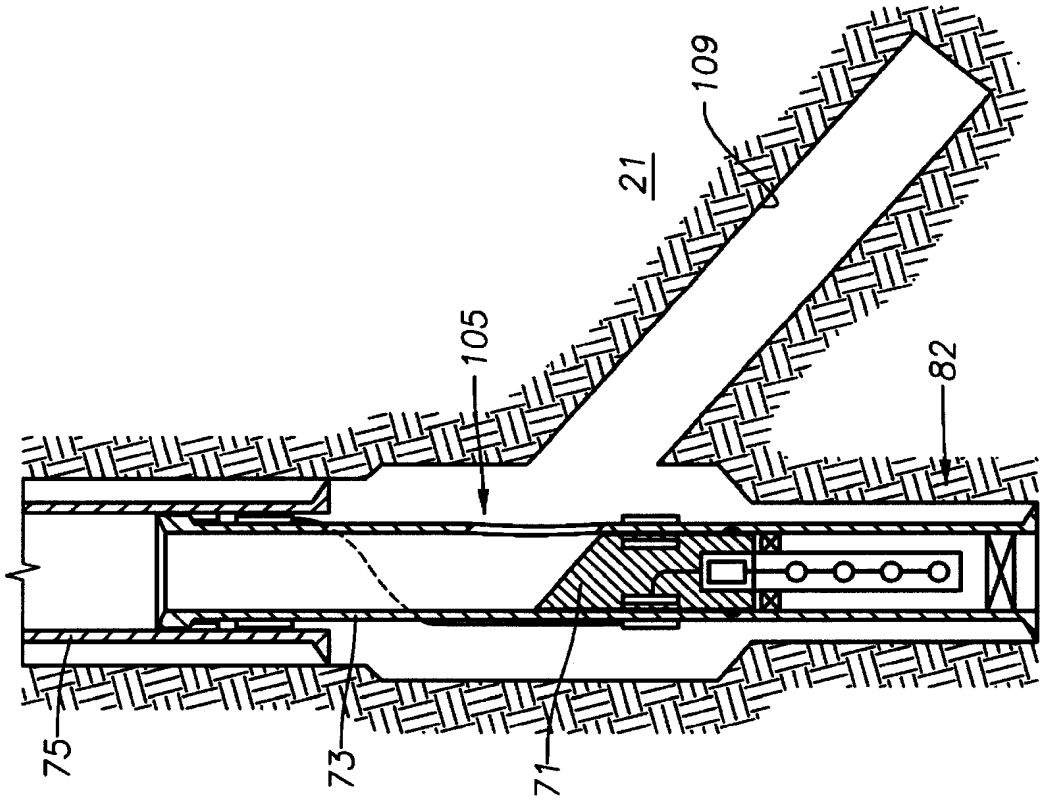

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Fig. 10

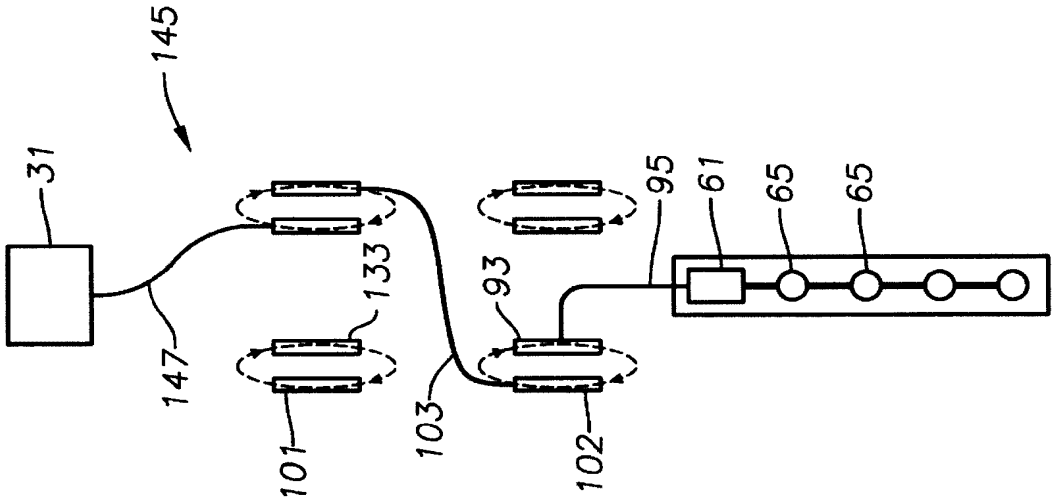


Fig. 13

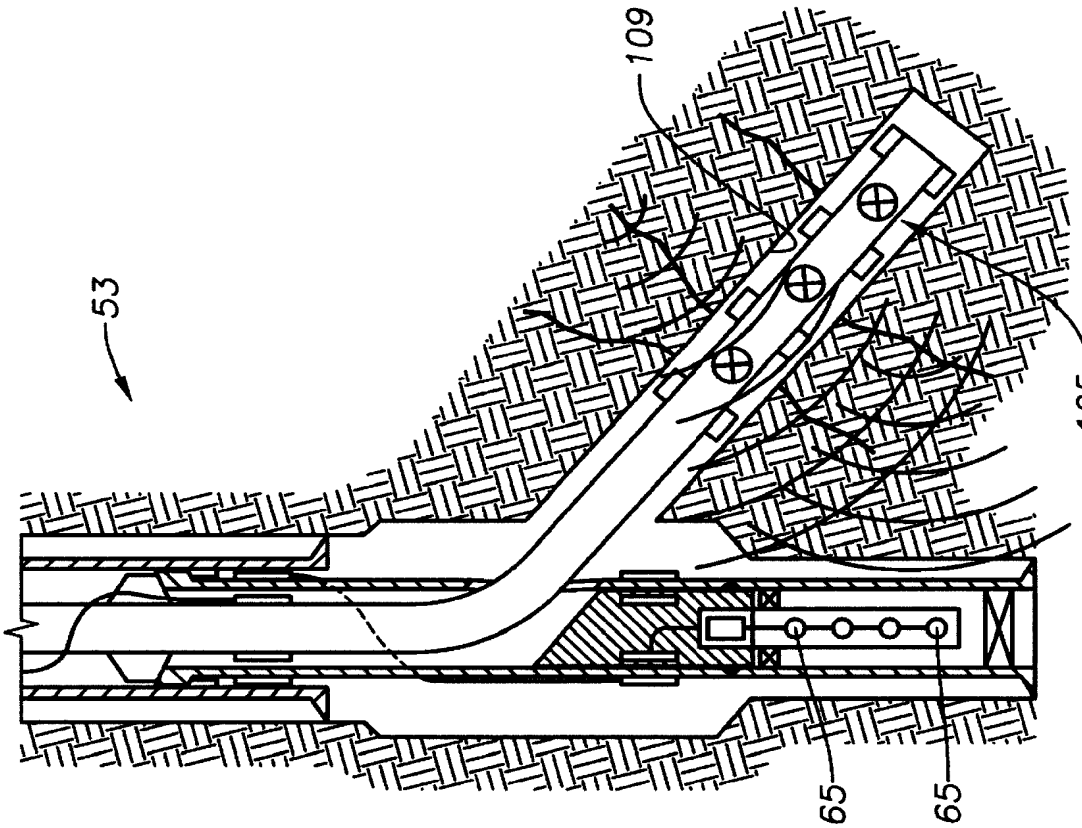


Fig. 12

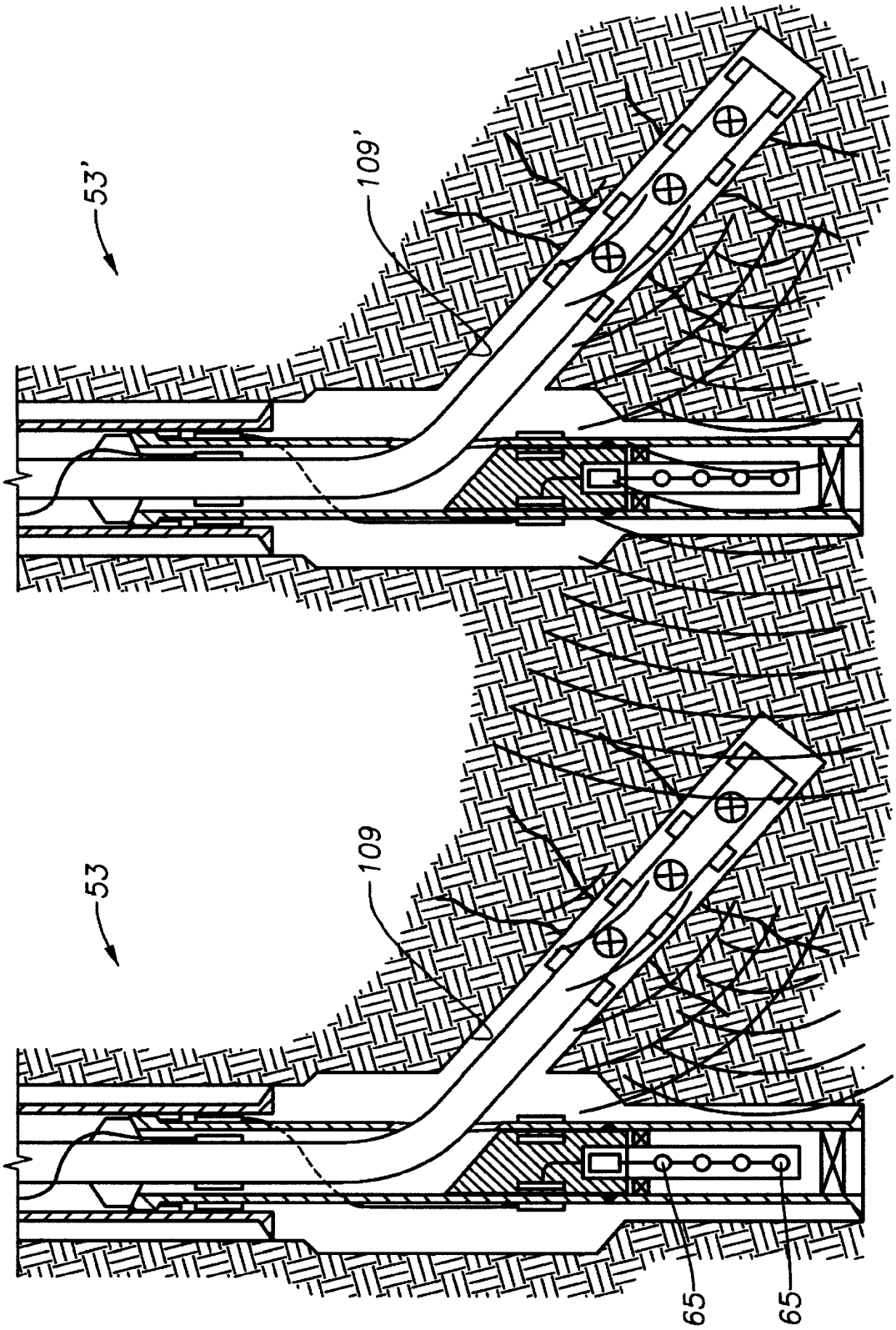


Fig. 14

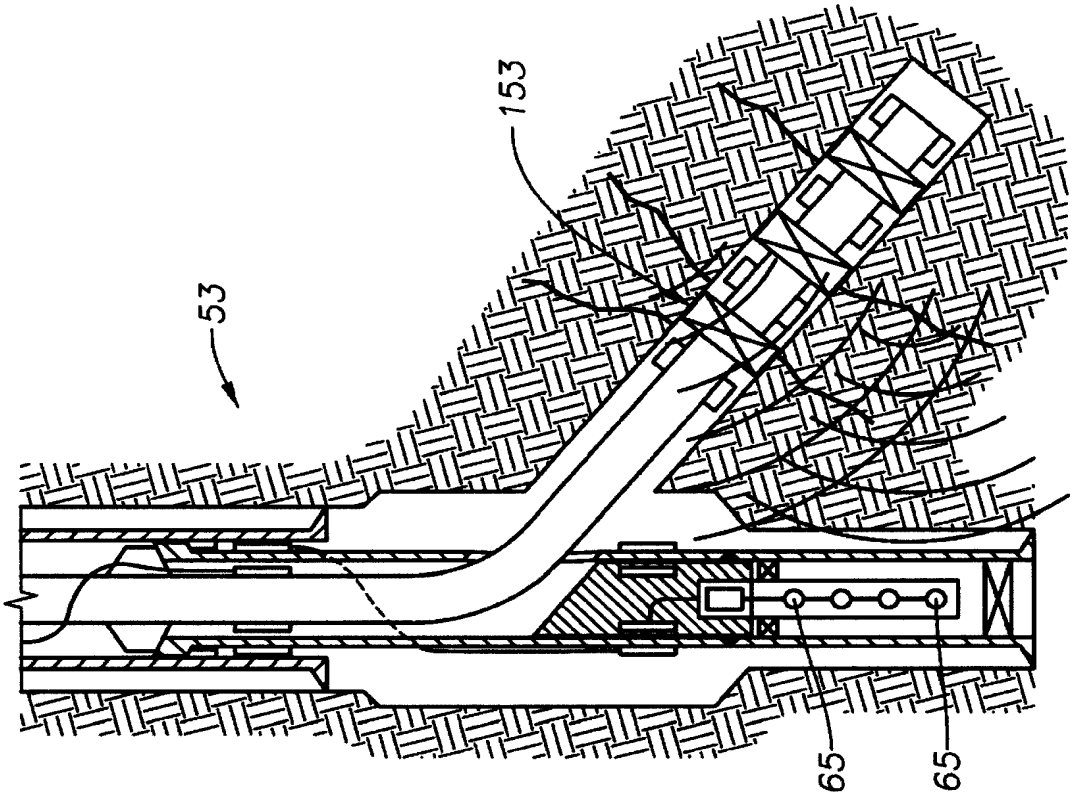


Fig. 16

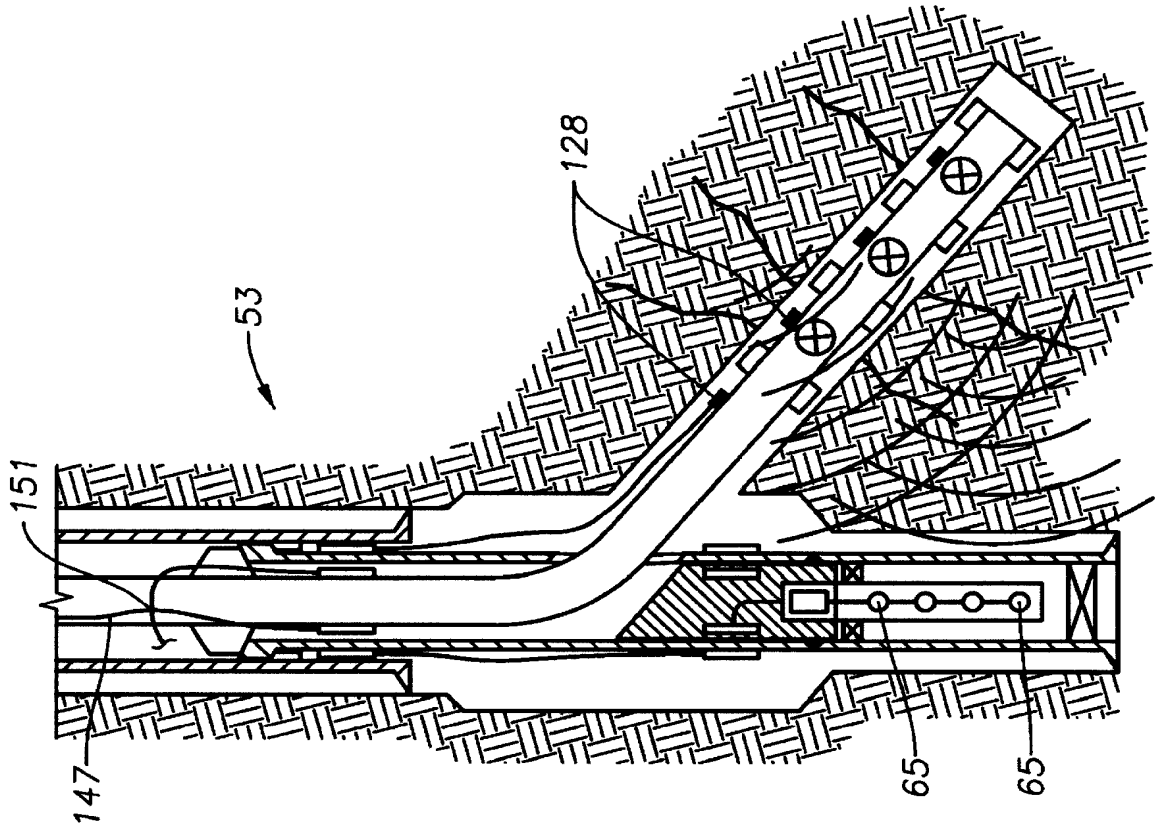


Fig. 15

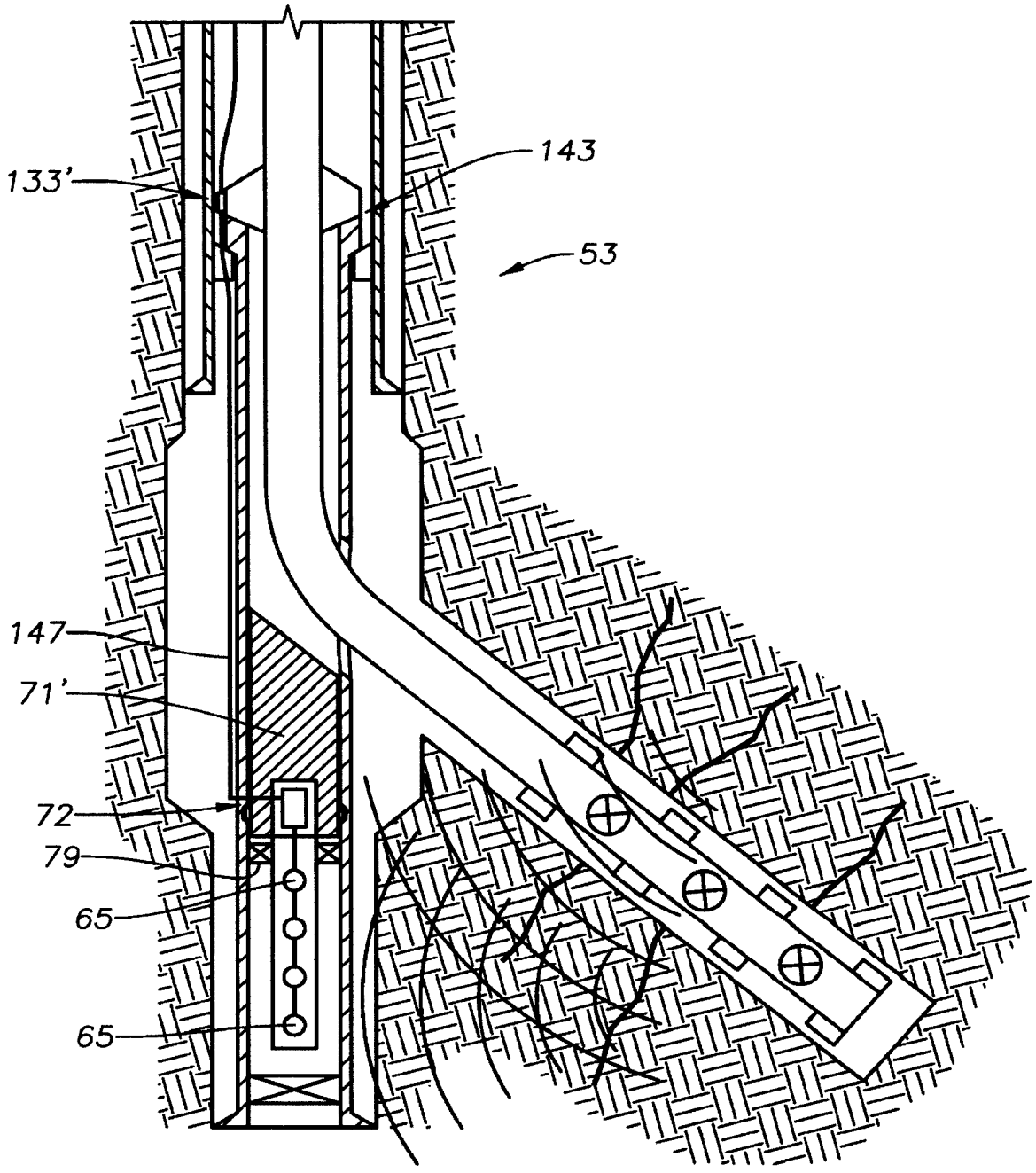


Fig. 17

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Canadian Intellectual Property Office

CA 3006422 A1 2017/06/01

(21) 3 006 422

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(86) Date de dépôt PCT/PCT Filing Date: 2016/11/28
(87) Date publication PCT/PCT Publication Date: 2017/06/01
(85) Entrée phase nationale/National Entry: 2018/05/25
(86) N° demande PCT/PCT Application No.: GB 2016/053730
(87) N° publication PCT/PCT Publication No.: 2017/089834
(30) Priorités/Priorities: 2015/11/27 (GB1521012.3); 2016/05/24 (GB1609093.8)

(51) Cl.Int./Int.Cl. *E21B 43/12* (2006.01), *E21B 43/14* (2006.01), *E21B 43/26* (2006.01)

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(74) Agent: MARKS & CLERK

(54) Titre : VANNE DE REGULATION DE DEBIT DE FOND DE TROU AUTONOME POUR CONTROLE DE PRESSION DE PUITS

(54) Title: AUTONOMOUS DOWNHOLE FLOW CONTROL VALVE FOR WELL PRESSURE CONTROL

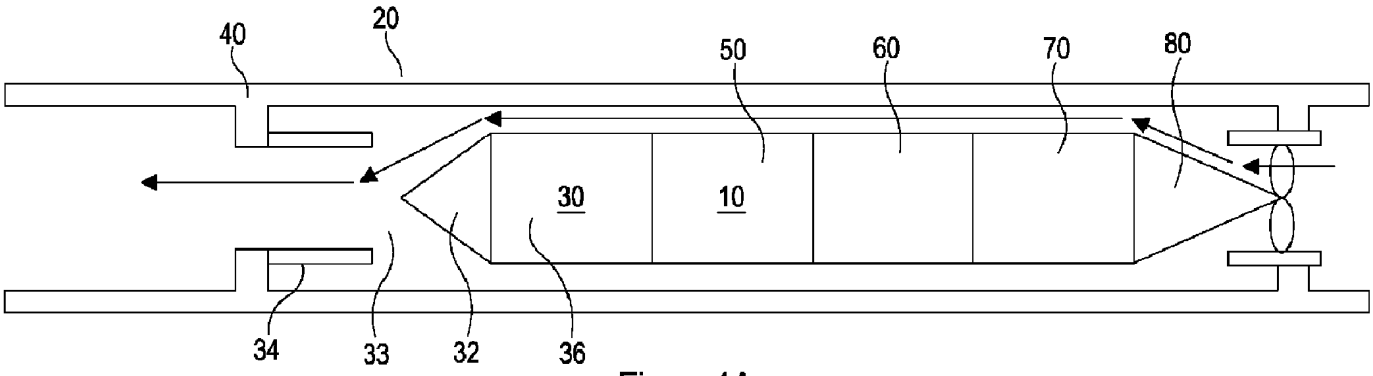


Figure 1A

(57) Abrégé/Abstract:
A downhole flow control device (10) is described having a flow control valve (30) and a sensor (50) in communication with the flow control valve. The sensor measures a downstream process parameter and the flow control valve is configured to control the fluid flow through the valve to achieve a target downstream process parameter value in response to the measured downstream process parameter. A control system for controlling the downhole flow control device and a method for controlling the downhole flow device are also provided.

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
1 June 2017 (01.06.2017)

WIPO | PCT

(10) International Publication Number
WO 2017/089834 A1

(51) International Patent Classification:
E21B 43/12 (2006.01) *E21B 43/26* (2006.01)
E21B 43/14 (2006.01)

(21) International Application Number:
PCT/GB2016/053730

(22) International Filing Date:
28 November 2016 (28.11.2016)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
1521012.3 27 November 2015 (27.11.2015) GB
1609093.8 24 May 2016 (24.05.2016) GB

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(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DJ, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Published:

— *with international search report (Art. 21(3))*

— *before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments (Rule 48.2(h))*

(54) Title: AUTONOMOUS DOWNHOLE FLOW CONTROL VALVE FOR WELL PRESSURE CONTROL

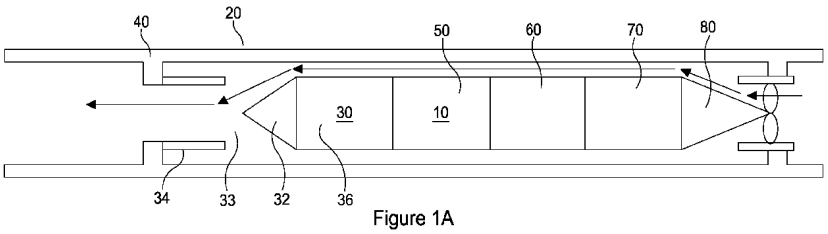


Figure 1A

(57) Abstract: A downhole flow control device (10) is described having a flow control valve (30) and a sensor (50) in communication with the flow control valve. The sensor measures a downstream process parameter and the flow control valve is configured to control the fluid flow through the valve to achieve a target downstream process parameter value in response to the measured downstream process parameter. A control system for controlling the downhole flow control device and a method for controlling the downhole flow device are also provided.

WO 2017/089834 A1

AUTONOMOUS DOWNHOLE FLOW CONTROL VALVE FOR WELL PRESSURE CONTROL

FIELD

The present disclosure relates to a flow control device, particularly a downhole flow control device and a method of controlling a flow control device.

BACKGROUND

Oil and gas fields typically comprise a number of wells which are processed by the same processing facility. The well conditions of each well may be different, for example, different wells may have different pressures. These differences can be due to, for example, penetrating different sections of the reservoir or different reservoir units. The variation in pressure can result in an imbalance of production across the wells.

Advanced completions or intelligent wells use valves or chokes in the reservoir that can be operated from the surface. These can be used to address or minimise the effect of imbalanced production across a formation.

Intelligent completion technology can be controlled from the surface using multiple hydraulic and/or electric control lines which have to pass through the wellhead into the completion annulus and run along the entire production line to where the valves are located. There are limitations associated with the use of control lines including the high costs associated with the equipment, complexity and risk during deployment.

Wireless intelligent completions utilise electronic controlled interval control valves which include sensors and in well processors which enables remote operation and control of the completion by the operator from the surface. Wireless telemetry, for example pressure pulses, is used to send and receive signals from downhole units to the surface. The ability of the downhole control valve to react to changes in the well environment remains in the hands of the operator on the surface.

During hydraulic fracturing operations, adjacent and nearby wells have to be isolated from the area being fractured. The wellhead is typically rated and designed to maintain a seal to isolate the well, however in practice a second barrier is usually provided to ensure pressure integrity. Two independent barriers for well control is normal practice and the second barrier is typically in the form of a retrievable plug installed downhole. After completion of the hydraulic fracturing operation, the plug is milled out. Any well within 0.5 to 1 mile of the fracking operation is required to be

protected in this manner and it may be required to carry out this operation 4 or 5 times per well. The costs of plugging and milling can quickly build up during a hydraulic fracturing operation.

SUMMARY

According to an aspect of the present disclosure, there is provided a downhole flow control device comprising:

a flow control valve;

a sensor in communication with the flow control valve, wherein the sensor measures a local process parameter; and

wherein the flow control valve is configured to control the fluid flow through the valve to achieve a target local process parameter value in response to the measured local process parameter.

In use, the downhole flow control device provides a means for monitoring and autonomously controlling the fluid production from a well. The flow control device will respond directly to changes in the downhole environment by changing the flow path through the valve as well conditions change without intervention from the surface of the well.

A local process parameter may be a process parameter measured in the vicinity of the flow control device. For example, the sensor may measure the downhole pressure at the location of the flow control device, and/or may measure the pressure drop across the flow control device, or measure the downhole pressure at the location of the flow control device.

The downhole flow control device may control the fluid flow through the flow control valve independently from external instruction, wherein external instruction comprises, for example, communication from the surface of the well, and/or input from an operator.

The downhole flow control device may be autonomous.

The local process parameter may be, for example, the downstream pressure, pressure drop across flow control valve, temperature, viscosity, or fluid composition, for example water content, measured in the vicinity of the flow control device when located downhole.

The target local process parameter value may be selected to maintain a surface process parameter of the well at a desired value or within a desired range.

The surface process parameter may be, for example, surface pressure or fluid flow rate.

For example, the local process parameter may be pressure and the target local process parameter value may be selected to maintain the surface pressure of the well.

The target local process parameter value may be determined through nodal analysis, for example nodal analysis may be performed on the well to determine a target process parameter value to produce a desired surface condition such as well head pressure.

The target local process parameter value may be programmed prior to deployment of the flow control device downhole.

The target local process parameter value may be re-programmable whilst the flow control device is in-situ. This increases the flexibility of the device to adjust to changing well conditions.

The target local process parameter value may be reprogrammed using downhole wireless communication such as wireless telemetry. This allows the flow control device to be re-programmable without the need for removal of the device from the well.

The flow control device may comprise wireless communication technology such as that described in WO2006/041308 and/or WO2006/041309. The flow control device may comprise a receiver and transmitter unit enabling it to be reconfigured using wireless telemetry.

Reconfiguring the flow control device may comprise a command to shutdown.

The local process parameter may be the same process parameter as the target process parameter, or it may be a different process parameter. For example, the target process parameter may be flow rate and the local process parameter may be pressure.

The flow control device may be configured to maintain the target downstream pressure at a predetermined level to keep the surface pressure at or below a predetermined level. The sensor may be selected to measure the local process parameter, for example a pressure sensor or a temperature sensor. The sensor may be chosen to measure any local process parameter, for example, pressure, temperature, flow rate, viscosity, fluid composition.

The flow control device may comprise a plurality of sensors configured to measure different local process parameters, for example a pressure sensor and temperature sensor.

The flow control device may be re-configurable to respond to different process parameters. For example, the flow control device may be configured to respond to a pressure reading from the sensor to achieve a target local pressure value, and the flow control device may be reconfigured to respond to a temperature reading and a pressure reading from temperature and pressure sensors to achieve a target downhole flowrate.

The flow control valve may comprise a choke valve.

The valve may comprise an electro-mechanical actuator, for example a piston or a sleeve.

The valve may be motor driven.

The valve may comprise a housing, wherein a piston is configured to extend and retract into or out of the housing to alter the flow area of the valve.

The valve may comprise an infinitely variable choke actuator.

The size of the flow control valve may be selected based on computational fluid dynamics (CFD) analysis performed to determine the range of valve size required to achieve the target local process parameter value.

A range of valve size may be preferable over a fixed valve size to account for declining reservoir pressure.

The flow control valve may further comprise a seal to facilitate the valve maintaining a seal when in a closed position.

The flow control device may comprise an electronics module.

The electronics module may act as a controller for the flow control valve.

The electronics module may act as the controller for the sensor.

The sensor and flow control valve may be controlled by a shared electronics module.

The electronics module may comprise an on-board processor.

The flow control device may use the target local process parameter value as a reference in a closed loop control system.

In use, the sensor may measure the local process parameter at set intervals. The processor may compare the measured local process parameter value with the target local process parameter value to determine if the actual local process parameter needs to be adjusted; the flow control valve may then alter the fluid flow through the valve to achieve the target local process parameter value.

The intervals may be selected depending on the process, for example measurements may be taken in second intervals, minute intervals, hour intervals, day intervals or week intervals.

The sensor may be configured to continuously measure the local process parameter as the flow control valve changes the fluid flow through the valve to achieve the target local process parameter value. The term “continuously” may comprise taking measurements at set intervals, where the intervals are short, for example taking a measurement every second, every five seconds, every 10 seconds. When the target local process parameter value has been reached, the flow control device may be configured to instruct the flow control valve to hold its position.

The flow control device may be configured to remain open until production is started. The flow control device may be located inside downhole tubing. This may allow for the flow control device to be retrievable.

The flow control device may be configured to form part of a downhole tubing string.

The tubing may be production tubing.

The flow control device may be located at any location within the production tubing, for example, the flow control device may be located to avoid hydrate formation. The flow control device may be located in the heel of the production tubing.

The flow control device may be an inflow control valve (ICV) for use in a production well.

The flow control device may be an inflow control valve for use in isolating at least a portion of the production well. For example, the flow control device may be used in hydraulic fracturing operations to isolate a distal portion of the well while hydraulic fracturing takes place in adjacent or nearby wells.

In use as an isolation valve, the target process parameter may be no fluid flow, or no fluid flow path or any process parameter associated with the flow valve being closed. The local process parameter may be, for example pressure or flow. The flow control valve may be configured such that when a pressure is detected within an accepted value or range, the flow control valve may close. The flow control valve may be configured such that when a flow rate of zero flow is detected, the flow control valve may close.

The flow control device may be configured to act as an isolation valve prior to running in hole.

The flow control device may be reconfigured to act as an isolation valve whilst in-situ downhole.

The flow control device may be designed to withstand a pressure up to a desired pressure value required to isolate the well, for example but not limited to, 8,000 psi, 10,000 psi.

A production well may be shut-in, for example from the surface, to stop production of the well. This may comprise closing a valve located at or near the surface of the production well. When a production well is shut-in, the downhole pressure at or near the flow control valve may increase.

The flow control device may be configured to detect when a shut-in of the well has taken place.

The flow control device may be configured to remain open until a shut-in of the well is detected. This may allow fluid flow through the flow control device during production of the well.

The flow control device may be used during the production of the well as a flow control device to maintain a desired surface process parameter and may be configured to be reconfigured whilst in-situ to be used as an isolation valve. For example the flow control device may be reconfigured using wireless telemetry to change the target process parameter to close the valve in response to a shut-in. The flow control device may be configured to measure the local pressure at set intervals. The intervals may be selected depending on the process, for example measurements may be taken in second intervals, minute intervals, hour intervals, day intervals or week intervals.

In use as an isolation valve, when a well is shut-in, the flow control device may detect an elevated local pressure. For example, an elevated pressure reading over a minimum period of time may indicate that the well has been closed and the flow control device may reconfigure to achieve the target process parameter of no fluid flow path through the valve.

The flow control device may be configured to recognise an elevated pressure value or increased pressure differential across the valve detected over a minimum time to be associated with a well shut-in. The minimum time may be, for example one minute, five minutes, ten minutes, fifteen minutes, twenty minutes, one hour, or any appropriate time interval required by the flow control device.

The flow control device may reconfigure to a closed position in response to a pressure indicating a shut-in of the well.

When the target local process parameter value has been reached, the valve may be closed and the flow control device may be configured to instruct the flow valve to hold this configuration.

In the closed position, the flow control device may maintain a seal and isolate at least a portion of the well, for example a distal portion of the well.

The flow control device may be configured to measure the local pressure whilst the flow control device is closed, for example, the flow control device may measure the local pressure at set intervals, for example every minute, or every five minutes, every ten minutes, every hour or any suitable interval, or the flow control device may be configured to measure the local pressure continuously whilst the flow control device is closed. The term "continuously" may comprise taking measurements at set intervals, where the intervals are short, for example taking a measurement every second, every five seconds, every 10 seconds.

The flow control device may be configured to open when the wellhead is opened, for example, after hydraulic fracturing operations have been completed.

The flow control device may be configured to open when the local pressure value above or below the valve corresponds to a value or within a pressure range associated with the well being open, or when a predetermined pressure differential across the valve is detected.

The flow control device may be configured to open or remain open when the local pressure is outside of an accepted range or value associated with the well being shut-in or associated with hydraulic fracturing operations occurring in adjacent or nearby wells, or the flow control device may be configured to open when the local pressure is within an accepted range associated with the well being open or hydraulic fracturing operations being complete. For example, when the well is opened or if hydraulic fracturing operations in nearby wells are stopped, the local pressure may decrease and the flow control device may be configured to respond to this pressure decrease by opening the flow control valve. A reduction in pressure measured over a minimum period of time may indicate that the well has been opened and the flow valve may open allowing the well to resume production.

The flow control device may be configured to remain closed until the flow control device is instructed to open, for example at such time as hydraulic fracturing operations in adjacent or nearby wells have been completed.

Instructing the flow control device to open may comprise sending a signal to the flow control device, for example using wireless telemetry. For example, a pressure

signal from the surface of the well may be sent to the flow control device when the well is opened following a shut-in, or in preparation for the well being opened following a shut-in. Upon receiving this pressure signal, the flow control device may open.

The flow control device may be configurable between an active and a passive configuration. In the passive configuration, the flow control device may measure a local process parameter, and compare the local process parameter to a target process parameter to, for example, determine whether the actual local process parameter needs to be adjusted. In the active configuration, the flow control valve may alter the fluid flow through the valve to achieve the target local process parameter value.

The flow control device may be configured to the active configuration during well shut-in. Additionally, or alternatively, the flow control device may be configured to the active configuration during production and/or when the wellhead is opened. The flow control device may be configured to the passive configuration once the target process parameter has been reached.

In the passive configuration, the flow control valve may not require to be altered. As such, in the passive configuration, the flow control device may consume less power than in the active configuration, thereby extending battery life, for example.

The flow control device may be configured to reset following opening after a shut-in such that the flow control device may remain open until another shut-in is detected.

The flow control device may be powered by a local power source.

The flow control device may be battery powered. The number of batteries may be selected according to the desired lifetime of the flow control device, for example one battery, two batteries, three batteries, or four batteries. The number of batteries may be limited by the rig-up height and handling of the flow control device.

The flow control device may be powered by a downhole generator. For example, the flow control device may be powered by a turbine for energy extraction from fluid flowing within a conduit, such as that described in UK patent publication number 2531025 and/or WO2016/055451 and/or WO2014118503.

According to a second aspect of the present disclosure, there is provided a control system for a downhole flow control device comprising:

a closed loop control system wherein a flow control valve located downhole adjusts to achieve a target local process parameter value in response to a measured local process parameter reading from a sensor in communication with the flow control valve.

The control system may comprise a plurality of sensors in communication with the flow control valve.

Each sensor may measure a different process parameter.

The target local process parameter value may be a reference in the closed loop control system.

The control system may be configured such that the sensor measures the downhole process parameter at set intervals. For example, the sensor may be configured to take measurements in second intervals, minute intervals, day intervals, week intervals or month intervals.

The control system may be configured to continuously measure the local process parameter as the flow valve adjusts the fluid flow through the valve to achieve the target local process parameter value. The term “continuously” may comprise taking measurements at set intervals, where the intervals are short, for example taking a measurement every second, every five seconds, every 10 seconds. When the target local process parameter value has been reached, the control system may be configured to instruct the flow valve to hold its position. The control system may be configured to be reprogrammable when required by well conditions, for example the target downhole process parameter value may be changed, the downhole process parameter may be changed, and the flow control valve may be shut down.

The control system may be reprogrammable whilst the downhole flow control device is in-situ.

The control system may be reprogrammable using downhole wireless telemetry, for example the wireless communication technology such as that described in WO2006/041308 and/or WO2006/041309.

The control system may be configured to set the flow control device to idle whilst no flow is detected. The control system may comprise an outer loop and an inner loop.

The outer loop may detect if the well is flowing and whether or not any communication is due to be received or sent from the flow control device. When flow is detected, the control system may move to the inner loop.

The inner control loop may determine if the measured downhole process parameter is within an accepted tolerance for the target local process parameter value and may adjust the flow valve accordingly. If the measured downhole process parameter is within the accepted tolerance for the target process parameter, the control system may move back to the outer loop.

The outer loop may measure a local downhole process parameter to determine whether the well has been shut-in at or near the surface. For example, an elevated local pressure over a minimum time may signal that the well has been shut-in. When a shut-in is detected, the control system may move to the inner loop. If no shut-in is detected, the outer control loop may take local downhole process parameters at set intervals.

The inner control loop may have a target local process parameter of no fluid flow, or no fluid flow path, or any process parameter associated with the flow control valve being closed. When the control system moves to the inner control loop, the control system may reconfigure the flow valve to achieve the target process parameter, for example the flow control valve will close.

The inner loop may measure the downhole process parameter at set intervals and whilst the downhole process parameter is within an accepted range, instruct the flow control valve to remain closed. If the downhole process parameter is not within the accepted range, the inner loop may instruct the flow valve to open and the control system may return to the outer loop.

For example, the downhole process parameter may be pressure. The inner loop may determine if the measured pressure or pressure differential across the flow control valve is within an accepted range for the flow valve to remain closed. The inner loop may determine if the measured pressure or pressure differential across the valve is within an accepted range for the flow valve to open. The accepted range may be a pressure or pressure range associated with the well being shut in or a pressure range associated with hydraulic fracturing operations taking place in adjacent or nearby wells, or the accepted range may be a pressure value or range associated with the wellhead being open, or associated with hydraulic fracturing operations being completed. If the inner loop determines the detected pressure value is below the accepted range or within the accepted range, the inner loop may instruct the flow control valve to open. For example, a decrease in local pressure to a pressure below the accepted range or within the accepted range, or a decrease in differential pressure across the valve may indicate that the wellhead has been opened and the flow valve can be opened.

The control system may be operable to set the flow control valve between the active configuration and the passive configuration. When the flow control valve is in the active configuration, the control system may operate using the inner loop. When the flow control valve is in the passive configuration, the control system may operate using the outer loop.

The control system may be configured to receive a communication from surface to open the flow valve. For example, a communication sent from the surface using wireless telemetry. The communication may be in the form of a pressure signal. Upon receipt of the communication, the control system may instruct the flow vale to open and the control system may return to the outer control loop.

Features described in relation to the flow control device of the first aspect apply mutatis mutandis to the second aspect.

According to a third aspect of the present disclosure, there is provided a method of controlling a downhole flow control device comprising:

programming a downhole flow control device with a target local process parameter value;

locating the downhole flow control device downhole, wherein the device comprises a flow control valve and a sensor in communication with the flow valve;

measuring a local process parameter with the sensor;

wherein the flow valve controls the fluid flow through the valve to achieve the target local process parameter in response to the measured local process parameter.

The method may be used to control fluid production from a well.

The method may comprise locating the downhole flow control device in production tubing, wherein the downhole flow device may form part of the tubing or be located inside the tubing.

The method may comprise a closed loop control system wherein the target local process parameter value is a reference.

The method may comprise reconfiguring the flow control device if necessary according to well conditions, for example the target downhole process parameter value may be changed, the downhole process parameter may be changed, and the flow control valve may be shut down.

The method may comprise reconfiguring the flow control device whilst the flow control device is in situ.

The method may comprise reconfiguring the flow control device using downhole wireless communication such as wireless telemetry, for example the wireless communication technology such as that described in WO2006/041308 and/or WO2006/041309.

The method may comprise operating the flow control valve during production of the well, for example where the target process parameter is selected to obtain a predetermined rate of production of the well. The target process parameter may be, for

example pressure, temperature, flow rate and viscosity. The local process parameter detected by the sensor may be, for example pressure, temperature, flow rate and viscosity. The local process parameter may be the same or different from the target process parameter.

The method may comprise operating the flow control valve as an isolation valve. In use as an isolation valve, the target process parameter may be no fluid flow, or no fluid flow path or any process parameter associated with the flow control valve being closed. The local process parameter may be pressure and the flow control valve may be configured such that when a pressure is detected within an accepted value or range, the flow control valve may close.

The method may comprise configuring the flow control device to operate as an isolation valve prior to running in hole.

The method may comprise configuring the flow control device to operate as an isolation valve whilst in-situ downhole.

The method may comprise isolating a portion of a well, for example a distal portion of the well.

The flow control device may be used to isolate a portion of the well during hydraulic fracturing operations to isolate a portion of the well while adjacent or nearby wells are being fractured.

The method may comprise detecting when the well has been shut-in. For example, the local process parameter may be pressure and the method may comprise the sensor measuring the downhole pressure. The method may comprise measuring the local pressure at set intervals. The intervals may be selected depending on the process, for example measurements may be taken in second intervals, minute intervals, hour intervals, day intervals or week intervals. An elevated pressure detected over a minimum period of time may indicate that the well has been closed and the flow valve may adjust to achieve the target process parameter of no fluid flow, wherein the fluid flow valve will close.

The method may comprise reconfiguring the flow control valve to a closed position to achieve the target local process parameter of zero flow, or zero fluid flow path in response to a pressure indicating a shut-in of the well.

The method may comprise maintaining the flow control valve in the closed position to isolate and seal a portion of the production well. The flow control valve may be designed to withstand a required pressure to isolate the well, for example but not limited to 8,000 psi or 10,000 psi.

The method may comprise opening the valve, for example when the well is opened. For example when a valve at the wellhead has been opened.

The method may comprise detecting when the well has been opened.

The method may comprise detecting if the measured local pressure or pressure differential is within an accepted range for the flow control valve to remain closed. The accepted range may be a pressure range associated with the well being shut in from surface or a pressure range associated with hydraulic fracturing operations taking place in adjacent wells. For example, when a well is shut-in, the pressure at or near the flow control valve may increase.

The method may comprise detecting if the measured local pressure or pressure differential across the valve is within an accepted range for the flow valve to open. The accepted range may be a reduced pressure range or pressure differential associated with the wellhead being open, or associated with hydraulic fracturing operations being completed.

The method may comprise determining if the measured pressure value is below the accepted range or within the accepted range and opening the flow control valve open. For example, a decrease in local pressure to a pressure below the accepted range or to within the accepted range may indicate that the wellhead has been opened and the flow valve can be opened.

The method may comprise sending a signal, for example a wireless communication to the flow control device to open the valve. For example, a pressure pulse sent from the surface may trigger the flow control valve to reopen.

The method may comprise operating the flow control valve during production of the well and reprogramming the flow control valve in-situ to operate as an isolation valve. The method may comprise operating the flow control valve as an isolation valve and reconfiguring the flow valve in-situ to operate during production of the well.

Features described in relation to the flow control device of the first aspect and the control system of the second aspect apply mutatis mutandis to the method of the third aspect.

According to a fourth aspect of the present disclosure, there is provided a downhole flow control device for isolating a portion of a well, the flow control device comprising:

a flow control valve;

a sensor in communication with the flow control valve, wherein the sensor measures a local process parameter; and

wherein the flow control valve is configured to close in response to the measured local process parameter.

In use, the downhole flow control device provides a means to isolate a portion of a well independently from external instruction, wherein external instruction comprises, for example, communication from the surface of the well, and/or input from an operator.

The flow control device may be autonomous.

The flow control device may be configured to isolate a portion of the well, for example a distal portion of the well during hydraulic fracturing operations on adjacent or nearby wells.

A local process parameter may be a process parameter measured in the vicinity of the flow control device. For example, the sensor may detect the downhole pressure at the location of the flow control device, and/or may measure the pressure drop across the fluid control device, or measure the downhole pressure at the location of the flow control device.

The local process parameter may be, for example, the downstream pressure or pressure drop across flow control valve measured in the vicinity of the flow control device when located downhole.

The flow control device may be located inside downhole tubing. This may allow for the flow control device to be retrievable.

The flow control device may be configured to form part of a downhole tubing string.

The tubing may be production tubing.

The flow control device may be located at any location within the production tubing, for example the flow control device may be located in the production tubing above the hydrocarbon bearing formation such that a distal portion of the well is isolated when the flow control valve is closed.

The flow control device may be an inflow control valve for use in isolating a portion of a production well. For example, the flow control device may be used to isolate a portion of the well while hydraulic fracturing takes place in adjacent or nearby wells.

In use as an isolation valve, the local process parameter may be, for example pressure or flow. The flow control valve may be configured such that when a pressure is detected within an accepted value or range, the flow control valve may close. The

flow control valve may be configured such that when a flow rate of zero flow is detected, the flow control valve may close.

The flow control device may be configured to act as an isolation valve prior to running in hole.

The flow control device may be reconfigured to act as an isolation valve whilst in-situ downhole.

The flow control device may be designed to withstand a pressure up to a desired pressure value required to isolate the well, for example but not limited to, 8,000 psi, 10,000 psi.

A production well may be shut-in, for example from the surface, to stop production of the well. This may comprise closing a valve located at or near the surface of the production well. When a production well is shut-in, the downhole pressure may increase and fluid flow will be zero.

The flow control device may be configured to detect when a shut-in of the well has taken place.

The flow control device may be configured to remain open until a shut-in of the well is detected. This may allow fluid flow through the flow control device during production of the well.

The flow control device may be used during the production of the well as a flow control device to maintain a desired surface process parameter and may be configured to be reconfigured whilst in-situ to be used as an isolation valve. For example the flow control device may be reconfigured using wireless telemetry to change the target process parameter to achieve a closed valve in response to a shut-in. The flow control device may be configured to measure the local pressure at set intervals. The intervals may be selected depending on the process, for example measurements may be taken in second intervals, minute intervals, hour intervals, day intervals or week intervals.

In use as an isolation valve, when a well is shut-in, the flow control device may detect an elevated local pressure. For example, an elevated pressure reading over a minimum period of time may indicate that the well has been closed and the flow control device may reconfigure to achieve the target process parameter of no fluid flow path through the valve.

The flow control device may be configured to recognise a pressure value or pressure differential across the valve detected over a minimum time to be associated with a well shut-in. The minimum time may be, for example one minute, five minutes,

ten minutes, fifteen minutes, twenty minutes, one hour, or any appropriate time interval required by the flow control device.

The flow control device may reconfigure to a closed position in response to a pressure indicating a shut-in of the well.

The flow control device may be configured to instruct the flow valve to hold this configuration.

In the closed position, the flow control device may maintain a seal and isolate at least a portion of the well, for example a distal portion of the well.

The flow control device may be configured to measure the local pressure whilst the flow control device is closed, for example, the flow control device may measure the local pressure at set intervals, for example every minute, or every five minutes, every ten minutes, every hour or any suitable interval, or the flow control device may be configured to measure the local pressure continuously whilst the flow control device is closed. The term "continuously" may comprise taking measurements at set intervals, where the intervals are short, for example taking a measurement every second, every five seconds, every 10 seconds.

The flow control device may be configured to open when the wellhead is opened, for example, after hydraulic fracturing operations have been completed.

The flow control device may be configured to open when the local pressure value above or below the valve corresponds to a value or within a pressure range associated with the well being open, or when a predetermined pressure differential across the valve is detected.

The flow control device may be configured to open or remain open when the local pressure is outside of an accepted range or value associated with the well being shut-in or associated with hydraulic fracturing operations occurring in adjacent or nearby wells, or the flow control device may be configured to open when the local pressure is within an accepted range associated with the well being open or hydraulic fracturing operations being complete. For example, when the well is opened or if hydraulic fracturing operations in nearby wells are stopped, the local pressure may decrease and the flow control device may be configured to respond to this pressure decrease by opening the flow control valve. A reduction in pressure measured over a minimum period of time may indicate that the well has been opened and the flow valve may open allowing the well to resume production.

The flow control device may be configured to remain closed until the flow control device is instructed to open, for example at such time as hydraulic fracturing operations in adjacent or nearby wells have been completed.

Instructing the flow control device to open may comprise sending a signal to the flow control device, for example using wireless telemetry. For example, a pressure signal from the surface of the well may be sent to the flow control device when the well is opened following a shut-in, or in preparation for the well being opened following a shut-in. Upon receiving this pressure signal, the flow control device may open.

The flow control device may be configured to reset following opening after a shut-in such that the flow control device may remain open until another shut-in is detected.

The flow control device may be reconfigured for use during production of the well. For example, the flow control device may be reconfigured to have a target local process parameter which is selected to maintain a desired surface process parameter. The flow control device may reconfigure the fluid flow path to achieve the target local process parameter is response to the measured local process parameter. The measured local process parameter may be re-programmed whilst the flow valve is in-situ.

The target local process parameter value and the local process parameter may be reconfigured using downhole wireless communication such as wireless telemetry. This allows the flow control device to be re-configurable without the need for removal of the device from the well.

The flow control device may comprise wireless communication technology such as that described in WO2006/041308 and/or WO2006/041309. The flow control device may comprise a receiver and transmitter unit enabling it to be reprogrammed using wireless telemetry.

The flow control valve may comprise a choke valve.

The valve may comprise an electro-mechanical actuator, for example a piston or a sleeve.

The valve may be motor driven.

The valve may comprise a housing, wherein a piston is configured to extend and retract into or out of the housing to alter the flow area of the choke valve.

The valve may comprise an infinitely variable choke actuator.

The size of the flow control valve may be selected based on computational fluid dynamics (CFD) analysis performed to determine the range of valve size required to achieve the target local process parameter value.

A range of valve size may be preferable over a fixed valve size to account for declining reservoir pressure.

The flow control valve may further comprise a seal to facilitate the valve maintaining a seal when in a closed position.

The flow control device may comprise an electronics module.

The electronics module may act as a controller for the flow control valve.

The electronics module may act as the controller for the sensor.

The sensor and flow control valve may be controlled by a shared electronics module.

The electronics module may comprise an on-board processor.

The flow control device may be powered by a local power source.

The flow control device may be battery powered. The number of batteries may be selected according to the desired lifetime of the flow control device, for example one battery, two batteries, three batteries, or four batteries. The number of batteries may be limited by the rig-up height and handling of the flow control device.

The flow control device may be powered by a downhole generator. For example, the flow control device may be powered by a turbine for energy extraction from fluid flowing within a conduit, such as that described in UK patent publication number 2531025 and/or WO2016/055451 and/or WO2014118503.

Features described in relation to other aspects of the present disclosure apply mutatis mutandis to the flow control vale of the fourth aspect.

According to another aspect of the present disclosure, there is provided a method of isolating a portion of a well during hydraulic fracturing operations, the method comprising

locating a flow control valve downhole,

closing the well;

closing flow control valve; and

performing hydraulic fracturing operations on an adjacent or nearby well.

The method may further comprise measuring a downhole process parameter with a sensor in communication with the flow control valve, wherein the flow control valve will close in response to the measured downhole process parameter.

The flow control valve may close without intervention from the surface of the well.

The downhole process parameter may be, for example pressure or flow.

The method may comprise detecting a pressure within an accepted value or range and closing the flow control valve.

The method may comprise detecting no fluid flow and closing the flow control valve.

The method may further comprise closing the well at or near the surface, for example by closing a valve located at or near the surface of the well.

The method may comprise detecting when a shut-in of the well has taken place.

The method may comprise configuring the flow control valve to remain open until a shut-in of the well is detected.

The method may further comprise producing through the valve. The method may further comprise producing when the valve is in an open or partially open configuration. The method may comprise configuring the flow control valve to maintain a desired surface process parameter, for example a pre-determined flow rate or pressure.

The method may comprise detecting an elevated local pressure and closing the flow control valve. For example, an elevated pressure reading over a minimum period of time may indicate that the well has been closed and the flow control device may close.

The method may comprise recognising a pressure value or pressure differential across the valve detected over a minimum time to be associated with a well shut-in. The minimum time may be, for example one minute, five minutes, ten minutes, fifteen minutes, twenty minutes, one hour, or any appropriate time interval required by the flow control device.

The method may comprise maintaining the flow control valve in the closed configuration. In the closed configuration, the flow control valve may maintain a seal and isolate at least a portion of the well, for example a distal portion of the well.

The method may comprise detecting the local pressure whilst the flow control valve is closed, for example, the flow control device may detect the local pressure at set intervals, for example every minute, or every five minutes, every ten minutes, every hour or any suitable interval, or the flow control valve may be configured to detect the local pressure continuously whilst the flow control valve is closed. The term “continuously” may comprise taking measurements at set intervals, where the intervals

are short, for example taking a measurement every second, every five seconds, every 10 seconds.

The method may further comprise opening the flow control valve. For example, the method may comprise opening the flow control valve after hydraulic fracturing operations on the adjacent or nearby well have been completed.

The method may comprise opening the flow control valve when the local pressure value above or below the valve corresponds to a value or within a pressure range associated with the well being open, or when a predetermined pressure differential across the valve is detected.

The method may comprise opening or holding the flow control valve open when the local pressure is outside of an accepted range or value associated with the well being shut-in or associated with hydraulic fracturing operations occurring in adjacent or nearby wells, or opening or holding the flow control valve open when the local pressure is within an accepted range associated with the well being open or hydraulic fracturing operations being complete. For example, when the well is opened or if hydraulic fracturing operations in nearby wells are stopped, the local pressure may decrease and the flow control valve may be configured to respond to this pressure decrease by opening the flow control valve. A reduction in pressure measured over a minimum period of time may indicate that the well has been opened and the flow valve may open allowing the well to resume production.

The method may comprise maintaining the flow control valve in the closed configuration until the flow control device is instructed to open, for example at such time as hydraulic fracturing operations in adjacent or nearby wells have been completed.

The method may further comprise instructing the flow valve to open. Instructing the flow control valve to open may comprise sending a signal to the flow control valve, for example using wireless telemetry. For example, a pressure signal from the surface of the well may be sent to the flow control valve when the well is opened following a shut-in, or in preparation for the well being opened following a shut-in. Upon receiving this pressure signal, the flow control device may open.

The method may further comprise reconfiguring the flow control valve to maintain a pre-determined production rate from the well. For example the flow control device may be reconfigured using wireless telemetry.

The method may comprise configuring the flow control valve between the active and passive configuration.

The method may comprise configuring the flow control valve to the active configuration during well shut-in.

Features described in relation to other aspects of the present disclosure apply mutatis mutandis to the method described in this aspect.

BRIEF DESCRIPTION OF THE DRAWINGS

These and other aspects of the present disclosure will now be described, by way of example only, with reference to the accompanying drawings, in which:

Figure 1a shows a schematic cut-away diagram of an in-line flow control device according to the present disclosure;

Figure 1b shows a schematic diagram of the flow control device shown in Figure 1a;

Figure 2a shows a schematic cut-away diagram of an annular flow control device according to the present disclosure;

Figure 2b shows a schematic diagram of the flow control device of Figure 2a;

Figure 3 shows a detailed schematic of the outer control and inner control loop for the fluid control device; and

Figure 4 shows a schematic of the flow control device of the present disclosure in use during a hydraulic fracturing operation.

DETAILED DESCRIPTION OF THE DRAWINGS

The downhole flow control device 10 in use is deployed within a wellbore which intercepts a subterranean formation which contains hydrocarbons. In the embodiment shown in Figures 1a and 1b, the flow control device 10 is deployed inside production tubing 20, configured to communicate fluids, such as gas, produced from the formation to the surface. Alternatively, the flow control device can form part of the production tubing, and will be run as part of the completion, either directly attached to the tail pipe or with the completion itself, as shown in Figures 2a and 2b.

The flow control device 10 has a flow control valve 30 in the form of a choke valve with an infinitely variable choke system. Choke valve 30 has an electro-mechanical piston 32 and a choke housing 34. The position of the piston 32 with respect to the choke housing forms a choke inlet 33. The valve 30 has a drive mechanism and motor 36 to move the piston of the choke valve. The flow control device has a sensor module 50 containing sensors to measure the desired process parameter. The skilled person will appreciate that the sensors may be chosen to

measure any downhole process parameter, for example, pressure, temperature, flow rate, viscosity, fluid composition. The sensors 55 are in communication with a sensor module 50 in the flow control device 10. An on-board electronics processor module 60 is present which controls both the sensors and the choke valve. The device 10 has a battery module 70 to provide power for the flow control device 10. The number of batteries selected will determine the lifetime of the valve. The batteries are thionyl chloride batteries, although any suitable batteries may be utilised. The number of batteries used is limited by the rig-up height and handling of the flow control device but the more batteries used the longer the life time of the flow control device, particularly in low temperature wells.

In addition to the battery module 70, the flow control device has a power generator 80. The power generator may be similar to that described in in UK patent publication number 2531025 and/or WO2016/055451 and/or WO2014118503. The skilled person will recognise that the flow control device may have either a battery module or a power generator or both as required by the intended use and design constraints of the flow control device.

Packers 40 will be present in the production tubing 20 between the flow control device 10 and the production tubing to isolate and seal the flow control device 10.

The fluid flow through the flow control device 10 is shown by the arrows in Figure 1a. As the piston 32 is moved away from or towards the choke housing 34, this increases or reduces the size of the choke inlet 33 and the fluid flow area through the valve 30 will be changed.

The flow control device 10 in position within the production tubing can also be seen in Figure 1b where flow ports 38 allowing fluid to flow into the valve are located at the upstream and downstream ends of the flow control device 10.

The flow control device 100 in Figure 2 is an annular flow control device 100 deployed as part of the production tubing 20 within downhole casing 25. The flow control device 100 has a flow control valve 300 in the form of a choke valve with an infinitely variable choke system. Choke valve 300 has an electro-mechanical variable position sleeve 320. The position of the sleeve 320 with respect to tubing 20 forms a choke inlet 330. The valve 300 has a drive mechanism and motor 360 to move the sleeve 320 towards or away from the tubing 20 reducing or increasing the size of the choke inlet 330. Similarly to the in-line embodiment of Figures 1a and 1b, the flow control device 100 has a sensor module 500 containing sensors to measure the desired process parameter. Again, the skilled person will appreciate that the sensors

may be chosen to measure any downhole process parameter, for example, pressure, temperature, flow rate, viscosity, fluid composition. The sensors 550 are in communication with a sensor module 500 in the flow control device 100. The sensors and choke valve are controlled by a shared on board electronics processor module 600. The device 100 has a battery module 700 to provide power for the flow control device 100 and a power generator module 800. The batteries are thionyl chloride batteries, although any suitable batteries may be utilised and the power generator may be similar to that described in in UK patent publication number 2531025and/or WO2016/055451 and/or WO2014118503. The skilled person will recognise that the flow control device may have either a battery module or a power generator or both as required by the intended use and design constraints of the flow control device.

Packers 40 are present in the casing 25 between the production tubing 20 and casing 25 to isolate and seal the flow control device 100. The flow through the flow control device 100 is shown by the arrows in Figure 2a. As the sleeve 320 is moved towards or away from the production tubing 20, this reduces or increases the size of the choke inlet 330 and the fluid flow area through the valve 30 will be adjusted.

The flow control device 100 in positon as part of the production tubing 20 located within casing 25 can also be seen in Figure 2b where flow ports 380 allowing fluid to flow into the valve are located at the upstream and downstream ends of the flow control device 10.

The flow control device 10, 100 is installed and located downhole. The location of the flow control device is selected to minimise hydrate formation. In this embodiment, the flow control device is installed at the heel of the well, where higher temperatures and pressures make hydrate formation unlikely. One skilled in the art will recognise that the flow control device may be installed at any location downhole as required by the particular production process.

The flow control device is programmed 10, 100 to target specific downhole well conditions in the vicinity of the flow control device, for example downstream pressure or choke pressure drop, prior to installation of the flow control device. The target local process parameter value is selected based on nodal analysis modelling to produce, for example, a required wellhead pressure. In this embodiment, the flow control device is programmed to have a target downstream pressure, although the skilled person will appreciate that any process parameter may be selected as the measured and target process parameter, for example, temperature, pressure, flow rate, viscosity, fluid composition.

The flow control device is autonomous. That is to say, the flow control device works by responding directly to a change in the environment of the well to change the flow path. The flow control device is programmed to maintain the target downstream pressure to keep the surface pressure at a manageable rate. The flow control device uses a closed loop control system where the target downstream pressure is the reference.

Once installed, the flow control device will be dormant until the well is placed on production. When production is detected the sensors will sample the downhole pressure at set intervals and pass this reading to the on-board processor. The processor will compare the measured value with the value set as the target pressure, and decide if the pressure needs to be adjusted or maintained.

If the pressure needs to be adjusted the piston will extend or retract into the choke housing, altering the fluid flow area as it moves. As flow through the valve changes, so does the upstream and downstream pressure. The flow control device sensors will continuously monitor the upstream and downstream pressure as the piston moves, and upon reaching the target pressure, the on-board processor will instruct the choke valve to hold that position.

It will be clear to the persons skilled in the art that the target local process parameter may be any useful, and measurable downhole process parameter, for example temperature, pressure, viscosity, fluid composition such as water content.

The measurement intervals of the flow control device are programmed such that when the well is placed on production, measurements are taken frequently in order for the target downstream pressure to be achieved. During periods of stable production, measurement intervals will be further apart and the valve will intermittently adjust to maintain production within the target conditions. This provides for optimum production as well conditions change over time.

An event such as plugging due to solids will be detected as a reduction in downstream pressure. The flow control device will instruct the choke valve to open to allow the solids to clear the choke, and will then re-adjust the choke position to once again maintain the target downstream pressure.

The flow control device can be reprogrammed during operations without retrieving the device from downhole. The flow control device has a receiver and transmitter unit located within the on-board electronics processor module 60 which utilise data from the sensors 55, enabling it to be reprogrammed using wireless telemetry. Wireless telemetry encompasses wireless downhole data communication as

known in the art, for example according to WO2006/041308 and WO2006/041309. Such reprogramming can include an adjustment to the target downstream pressure if required by changing well conditions, or a simple shutdown command.

A detailed description of the control process for the fluid control device is shown in Figure 3. The control process has two loops, an outer loop and an inner loop. The outer loop detects if the well is flowing and whether or not any communication is due to be received or sent from the flow control device. The inner control loop determines if the sampled data is within the accepted tolerance for the target process parameter value and adjusts the flow valve accordingly. A description of each block of the flow diagram is provided in Table 1. In some examples, control process of the fluid control device operating on the outer loop corresponds to the fluid control device having a passive configuration, while the fluid control device operating on the inner loop corresponds to the fluid control device having an active configuration.

In use, the flow control device is completely autonomous such that the choke valve will adjust the fluid flow area directly in response to the measured downstream pressure in order to meet the target downstream pressure. Aside from reprogramming, the flow control device will operate without any communication from the surface and therefore, in normal operating circumstances, will not require any input from an operator and will not require control or power lines from the surface. Further, the flow control device is configurable between an active and a passive configuration. In the passive configuration, the flow control device measures a local downstream process parameter at select intervals, and compares the local process parameter to a target process parameter, for example, to determine whether the actual local process parameter need to be adjusted. In the active configuration, the flow control valve alters the fluid flow through the valve to achieve the target local process parameter value.

Figure 4 illustrates a schematic of production wells 300 and 400. The flow control device 200 can be used as an inflow control valve for use in isolating a distal portion 320 of a production well 300. The flow control device 200 may be required during hydraulic fracturing operations to isolate a portion of the well 300 while hydraulic fracturing operations 600 take place in adjacent well 400. The flow control valve 200 is designed to withstand pressures of up to 10,000 psi.

Whilst the flow control valve 200 is being run in hole, the on-board processor will ignore pressure changes measured by the sensors. Once at setting depth and following setting of the device, the sensors will detect production flow and choke the valve twice, at a fixed time interval apart. The pressure pulses detected at surface as a

result of the valve choking confirm the flow control device is active. The flow control device will then remain open until a shut-in of the well is detected. Well 300 can be shut-in at surface by closing valve 310.

In use as an isolation valve, the flow control valve 200 has a target process parameter of no fluid flow path, that is the valve is closed and isolates the well. The sensors detect downhole pressure at set intervals and pass this reading to the on-board processor. The sensors are located within the sensor module of the flow control device and the reading is sent directly to the on-board processor which is also located downhole. Therefore, the valve can change the fluid flow path through the valve to achieve the target process parameter without intervention from the surface of the well. The processor will compare the measured value with a programmed value or range associated with the well being shut-in at the surface. When the well is shut-in, the downstream pressure will increase and the sensors will detect this pressure profile. The on-board processor is configured to recognise that an elevated pressure reading within an accepted range over a minimum period of time is associated with a shut-in of the wellhead and the on-board processor will instruct the valve to close. Thus, once the on-board processor recognises an elevated pressure reading, the flow control device 200 will configure from the passive configuration to the active configuration to close the flow control device 200. The rise in pressure associated with a shut-in is a preset value and the on board processor will detect if the rise in pressure has occurred and that the rise in pressure in maintained for preset period of time. For example, the on-board processor will look for a 15 bar increase in pressure that is maintained for at least 60 minutes. The increase in pressure could be more than 15 bar and could last infinitely. The preset values of pressure and time can be selected based on well analysis, reasoned judgements and estimates as appropriate for a particular production well.

Whilst the pressure readings detected by the sensors are outside of the accepted range or preset value, typically lower than the shut-in pressure, the flow control valve will remain open, allowing normal production of the well. In this manner, the flow control valve 200 will ignore any pressure variances that may result from, for example a downhole pump or a beam pump in the well and will close only when a shut-in is detected. Alternatively, the flow control valve 200 may be configured to detect production of the well as function of the difference between two pressure sensors and a shut-in would be detected when both sensors read the same or similar pressure.

When the valve has closed, the on-board processor will instruct the flow control valve to hold its position until valve 310 has been reopened or until the valve is instructed to open. The flow control valve will maintain an 8,000 psi static seal.

With both the surface valve 310 and flow control valve 200 closed, hydraulic fracturing operations can commence on neighbouring well 400. During hydraulic fracturing operations, high pressure fluid (indicated by the arrows in Figure 4) is pumped into production well 400 by pump 600 and into the hydrocarbon bearing formation 500. Proximal portion 320 of production well 300 is isolated from the high pressure hydraulic fracturing fluid by the flow control valve 200. The flow control valve 200 may be configured to continue to detect the downhole pressure at set intervals whilst in the valve is closed and may be configured to react to pressure from the reservoir 500 due to hydraulic fracturing operations.

The flow control device is configured to remain closed until a communication is received from surface instructing the valve to open following completion of hydraulic fracturing operations. The communication is in the form of a pressure pulse signal or multiple pressure signals within a set interval sent from the surface and received by the receiver unit located within the on-board processor module 60. In this application, over pressure is applied from the surface at a specific value for a specific period of time, for example 20 bar for 30 minutes. The on-board processor will detect this over pressure and instruct the flow control valve to open after a pre-determined time delay. When multiple pressure pulse signals are sent to the flow control valve 200, the time gap between each signal can be used to instruct the time delay before opening, the speed of opening of the valve and/or the position of opening, for example instruct the valve to open fully or to an intermediate open configuration.

Alternatively, the flow control valve 200 may be configured such that when the well is opened at valve 310 and the pressure detected by the sensors decreases, the on-board processer may instruct the flow valve 200 to open when a pre-determined pressure differential across the valve is detected by the flow control valve, such as 3,000 psi or 500 psi, that is associated with the well being open. The flow control device will then reset to open and normal production of the well can resume until the next well shut-in is detected by the flow control device.

The flow control valve 200 is configured to recognise pressure changes associated with a shut-in, and therefore, the flow control valve 200 is configured to ignore the high pressures associated with a hydraulic fracturing operation such that it is possible to carry out hydraulic fracturing operations on a production well 300 with the

flow control valve 200 installed. For example, a shut-in may result in a pressure change of between 15 and 30 bar and a hydraulic fracturing operation may be 300 to 600 bar; the flow control valve 200 is configured to recognise the associated pressure changes and will remain fully open during hydraulic fracturing operations of the well in which the valve 200 is installed.

The flow control device 200 can be configured act as an isolation valve and can be configured prior to running in hole to recognise and react to the specific pressure changes associated with a well shut-in and hydraulic fracturing operations, as described above. The flow control valve 200 can also be reconfigured whilst in-situ from the surface using wireless telemetry such that the preset pressure values are changed or to reconfigure the flow control valve to act as flow control device to maintain a surface production rate

Table 1 – Description of Process Control stages

Outer process control loop	
Idle	The control system will wait on "Idle" in the outer control loop on a timer (typically daily) that will instruct the flow control device to check if the well is flowing, to detect/send pressure pulse telegrams, and to do a regulation check.
Flowing conditions detected	The flow control device will only move to the telegram check if the device detects flowing conditions.
Telegram detected/due	If flowing conditions are detected, the device will check to see if any communication from the surface has been detected or is due to be sent. If not, flow control device will move onto regulation check
Time for regulation check	The flow control device will check to see if it is due to regulate the valve parameters. If so, the flow control device will enter the inner process control loop.
Inner process control loop	
Time for sample	The inner loop will sample at a much higher frequency, typical in seconds. If time for a sample it will access the data from the attached sensors.
Sample acquisition device	Processer will request and receive data from the attached sensors.
Within tolerance	The on-board processor will check to determine if the sampled data is within the pre-defined range for that parameter. If so, the device will go back to the outer loop. If not, the device will check if the well

	is flowing.
Well flowing	Shut in on surface can be detected by a build-up in tubing pressure. If the device detects this it will go back to the outer loop. If the flow control device detects the well is still flowing, the motor driving the piston/sleeve of the valve will be powered on to adjust the valve.
Adjust valve	The direction of the motor driving the valve will depend on whether the sample data is + or – of tolerance (moving the piston in or out of choke housing). The inner process control loop will continue until data is within tolerance or a shut in is detected, in which case the control system will return to idle on the outer control loop.

Claims

1. A downhole flow control device comprising:

a flow control valve;

a sensor in communication with the flow control valve, wherein the sensor measures a local process parameter; and

wherein the flow control valve is configured to control the fluid flow through the valve to achieve a target local process parameter value in response to the measured local process parameter.

2. The downhole flow control device of claim 1, wherein the fluid flow through the valve is adjusted independently from external instruction.

3. The downhole flow control device of claims 1 to 2, wherein the device is autonomous.

4. The downhole flow control device of any preceding claim, wherein the target local process parameter value is programmed prior to deployment of the flow control device downhole.

5. The downhole flow control device of claim 4, wherein the target local process parameter value can be reprogrammed whilst the flow control device is downhole.

6. The downhole flow control device of claim 4 or 5, wherein the target local process parameter value can be reprogrammed using downhole wireless communication.

7. The downhole flow control device of any preceding claim, wherein the local process parameter is the same as the target local process parameter.

8. The downhole flow control device of any of claims 1 to 6, wherein the local process parameter is different from the target local process parameter.

9. The downhole flow control device of any preceding claim comprising a plurality of sensors configured to measure different process parameters.

10. The downhole flow control device of any of claim 10, wherein the flow control device is reprogrammable to respond to different process parameters.

11. The downhole flow control device of any preceding claim wherein the target local process parameter value is selected to maintain a surface process parameter of the well at a desired value, or within a desired range.

12. The downhole flow control device of any preceding claim wherein the target local process parameter value is determined by nodal analysis.

13. The downhole flow control device of any preceding claim wherein the flow control valve is an infinitely variable choke valve.

14. The downhole flow control device of any preceding claim wherein the flow control device uses the target local process parameter value as a reference in a closed loop control system.

15. The downhole flow control device of any preceding claim, wherein the sensor is configured to measure the local process parameter at set intervals.

16. The downhole flow control device of any preceding claim, wherein the sensor is configured to measure the local process parameter continuously as the flow valve adjusts the fluid flow through the valve to achieve the local process parameter value.

17. The downhole flow control device of any preceding claim, wherein the flow control device is configured to be located inside downhole tubing.

18. The downhole flow control device of any of claims 1 to 16, wherein the flow control device is configured to form part of the downhole tubing.

19. The downhole flow control device of any preceding claim, wherein the flow control device is configured to be located downhole at a location selected to minimise the formation of hydrates.

20. The downhole flow control device of any preceding claim, wherein the flow control valve is configured to control the fluid flow path through the valve to close the flow path.

21. The downhole flow control device of claim 20 wherein the flow control device is configured to close in response to a pressure indicating a shut-in.

22. The downhole flow control device of claim 21 wherein the flow control device is configured to open when the well is opened after the shut-in.

23. The downhole flow control device of claim 21 wherein the flow control device is configured to remain closed until the device is instructed to open.

24. The downhole flow control device of claim 23 wherein the flow control device is instructed to open using wireless telemetry.

25. The downhole flow control device of any preceding claim, wherein the flow control device is configurable between an active configuration and a passive configuration.

26. The downhole flow control device of claim 25, wherein the flow control device is configured to the active configuration during well shut-in.

27. The downhole flow control device of claim 25, wherein the flow control device is configured to the passive configuration when the well is opened after a well shut-in.

28. A control system for a downhole flow control device comprising:

a closed loop control system wherein a flow control valve located downhole adjusts to achieve a target local process parameter value in response to a measured local process parameter reading from a sensor in communication with the flow control valve.

29. The control system of claim 28, wherein the target local process parameter value is a reference is the closed loop control system.

30. The control system of claim 28 or 29, configured to be reprogrammable whilst the flow control valve is located downhole.

31. The control system of claim 30, wherein the control system is reprogrammable using wireless downhole communication.

32. The control system of any of claims 28 to 31 wherein the target local process parameter is no fluid flow path through the valve.

33. The control system of claim 32 wherein the control system instructs the flow control valve to close to achieve the target local process parameter of no fluid flow in response to a pressure readings indicating a shut-in.

34. The control system of claim 33 wherein the control system instructs the flow control valve to open when the wellhead is opened after the shut-in.

35. The control system of claim 33 or 34 wherein the control system instructs the flow control valve to remain closed until the control system is instructed to open the valve.

36. The control system of any of claims 28 to 35, wherein the control system is operable to set the flow control valve between the active configuration and the passive configuration.

37. The downhole flow control device of claim 35 wherein the flow control device is instructed to open using wireless telemetry.

38. A method of controlling a downhole flow control device comprising:

programming a downhole flow control device with a target local process parameter value;

locating the downhole flow control device downhole, wherein the device comprises a flow control valve and a sensor in communication with the flow valve;

measuring a local process parameter with the sensor;

wherein the flow valve controls the fluid flow through the valve to achieve the target local process parameter in response to the measured local process parameter.

39. The method of claim 38 wherein the method is used to control fluid production from a well.

40. The method of claim 38 or 39 comprising locating the flow control device inside production tubing.

41. The method of claims 38 or 39 comprising locating the flow control device downhole as part of the production tubing.

42. The method of any of claims 38 to 41 comprising reprogramming the flow control device when required by well conditions whilst the flow control device is downhole.

43. The method of claims 42 comprising reprogramming the flow control device using wireless downhole communication.

44. The method of any of claims 38 to 43 comprising controlling the fluid flow path through the valve to close the flow path.

45. The method of claim 44 comprising closing the flow control valve in response to a pressure indicating a shut-in.

46. The method of claim 45 comprising keeping the control valve to closed until the flow control device is instructed to open the valve.

47. A downhole flow control device for isolating a portion of a well, the flow control device comprising:

a flow control valve;

a sensor in communication with the flow control valve, wherein the sensor measures a local process parameter; and

wherein the flow control valve is configured to close in response to the measured local process parameter.

48. The downhole flow control valve of claim 47, wherein the measured local process parameter is a pressure indicating a shut-in.

49. The downhole flow control valve of claims 47 or 48, wherein the valve is configured to remain closed until the valve is instructed to open.

50. The downhole flow control valve of claims 49, wherein flow control device is instructed to open the valve using wireless telemetry

51. A method of isolating a portion of a well during hydraulic fracturing operations, the method comprising

locating a flow control valve downhole,

closing the well;

closing flow control valve;

performing hydraulic fracturing operations on an adjacent or nearby well.

52. The method of claim 51 comprising measuring a downhole process parameter with a sensor in communication with the flow control valve, wherein the flow control valve will close in response to the measured downhole process parameter.

53. The method of claim 51 or 52 comprising closing the valve without intervention from the surface of the well.

54. The method of any of claims 51 to 53 comprising closing the well at or near the surface.

55. The method of any of claims 51 to 54 comprising detecting when a shut-in of the well has taken place.

56. The method of any of claims 51 to 55, comprising configuring the flow control valve to remain open until a shut-in of the well is detected.

57. The method of any of claims 51 to 56 comprising producing through valve.

58. The method of any of claims 51 to 57 comprising configuring the flow control valve to maintain a desired surface process parameter.

59. The method of claim 58 comprising configuring the flow control valve in-situ.

60. The method of any of claims 51 to 59 comprising detecting a pressure within an accepted value or range and closing the flow control valve.

61. The method of any of claims 51 to 60 comprising maintaining the flow control valve in the closed configuration.

62. The method of any of claims 51 to 61 comprising detecting the local pressure whilst the flow control valve is closed.

63. The method of any of claims 51 to 62 comprising opening the flow control valve.

64. The method of any of claims 51 to 63 comprising opening the flow control valve after hydraulic fracturing operations on the adjacent or nearby well have been completed.

65. The method of any of claims 51 to 63 comprising opening the flow control valve when a local pressure value or above or below the valve is within a pressure range associated with the well being open.

66. The method of any of claims 51 to 63 comprising maintaining the flow control valve in the closed configuration until the flow control device is instructed to open.

67. The method of any of claims 51 to 66, comprising configuring the flow control valve between an active configuration and a passive configuration.

68. The method of any of claims 51 to 67, comprising configuring the flow control valve to the active configuration during well shut-in.

69. The method claim 66 wherein instructing the flow valve to open comprises sending a signal to the flow control valve.

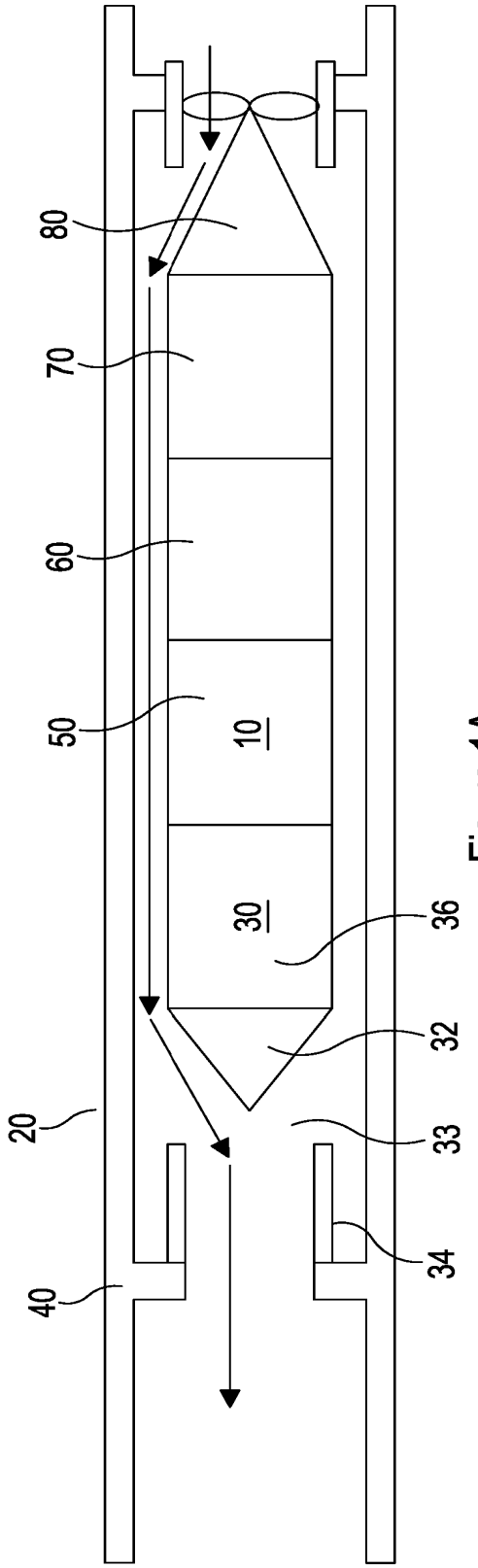


Figure 1A

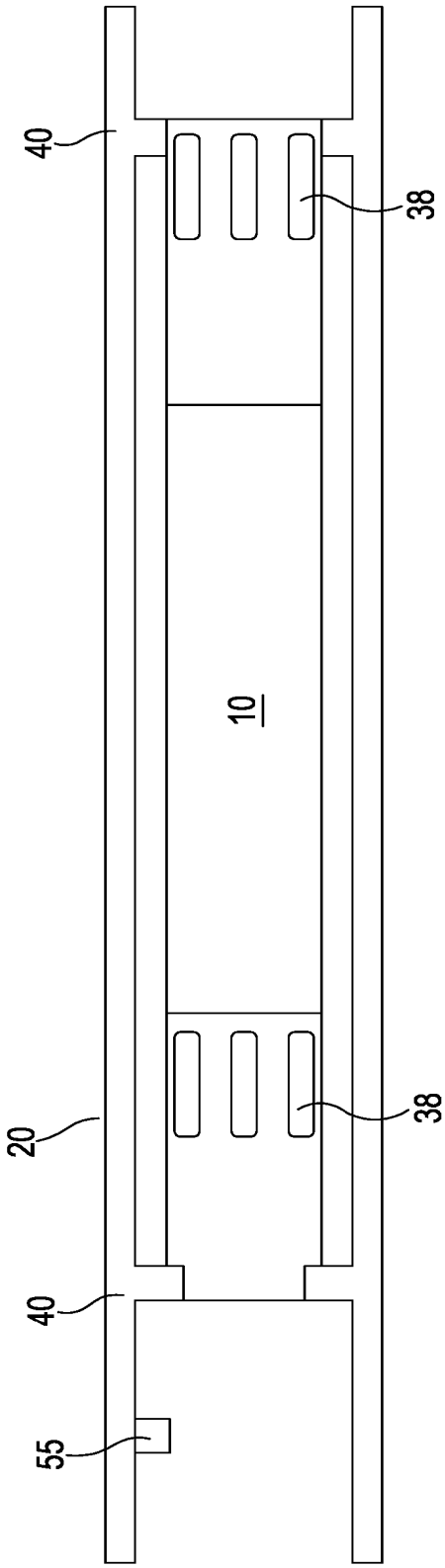


Figure 1B

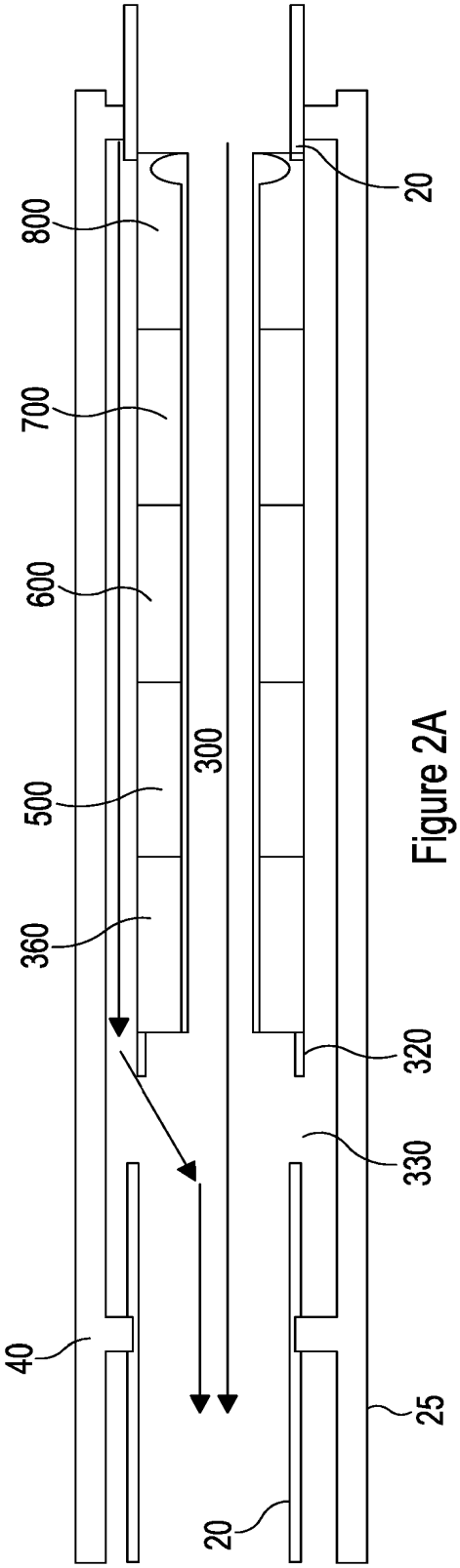


Figure 2A

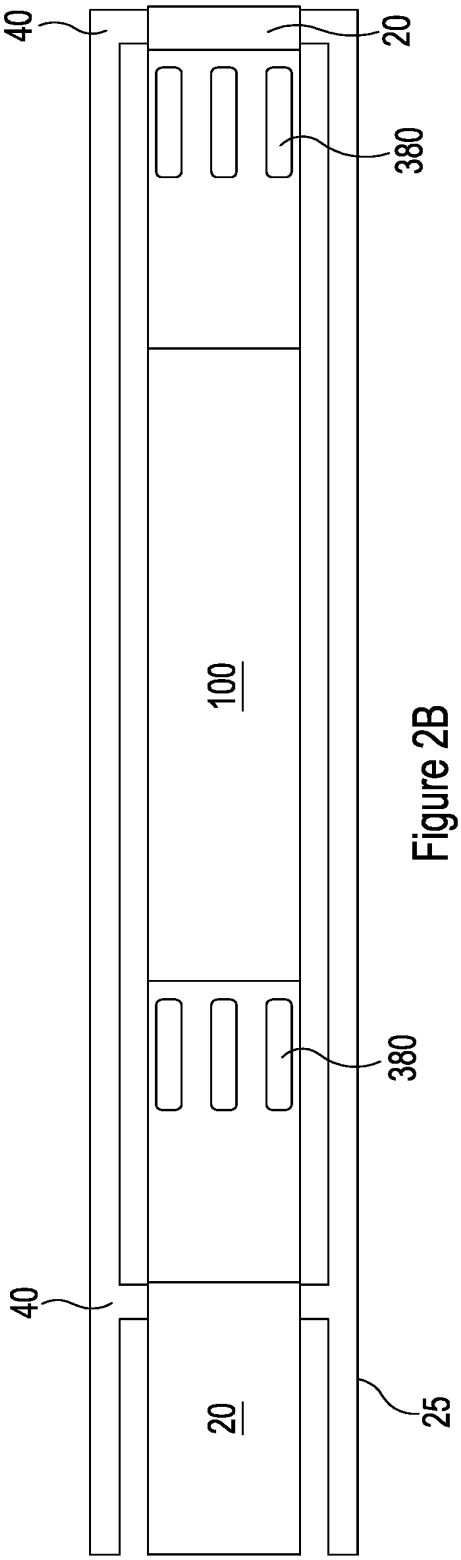


Figure 2B

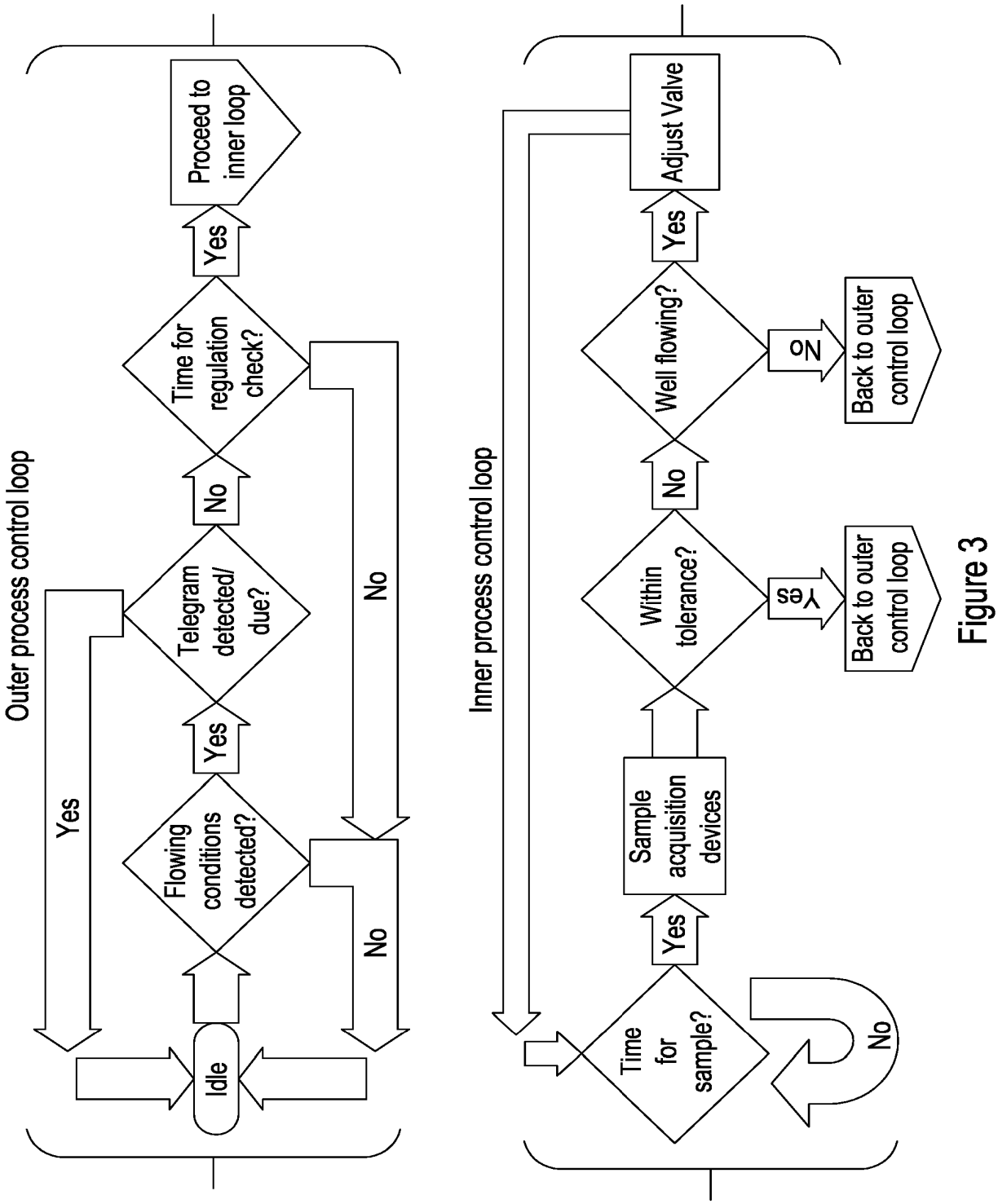


Figure 3

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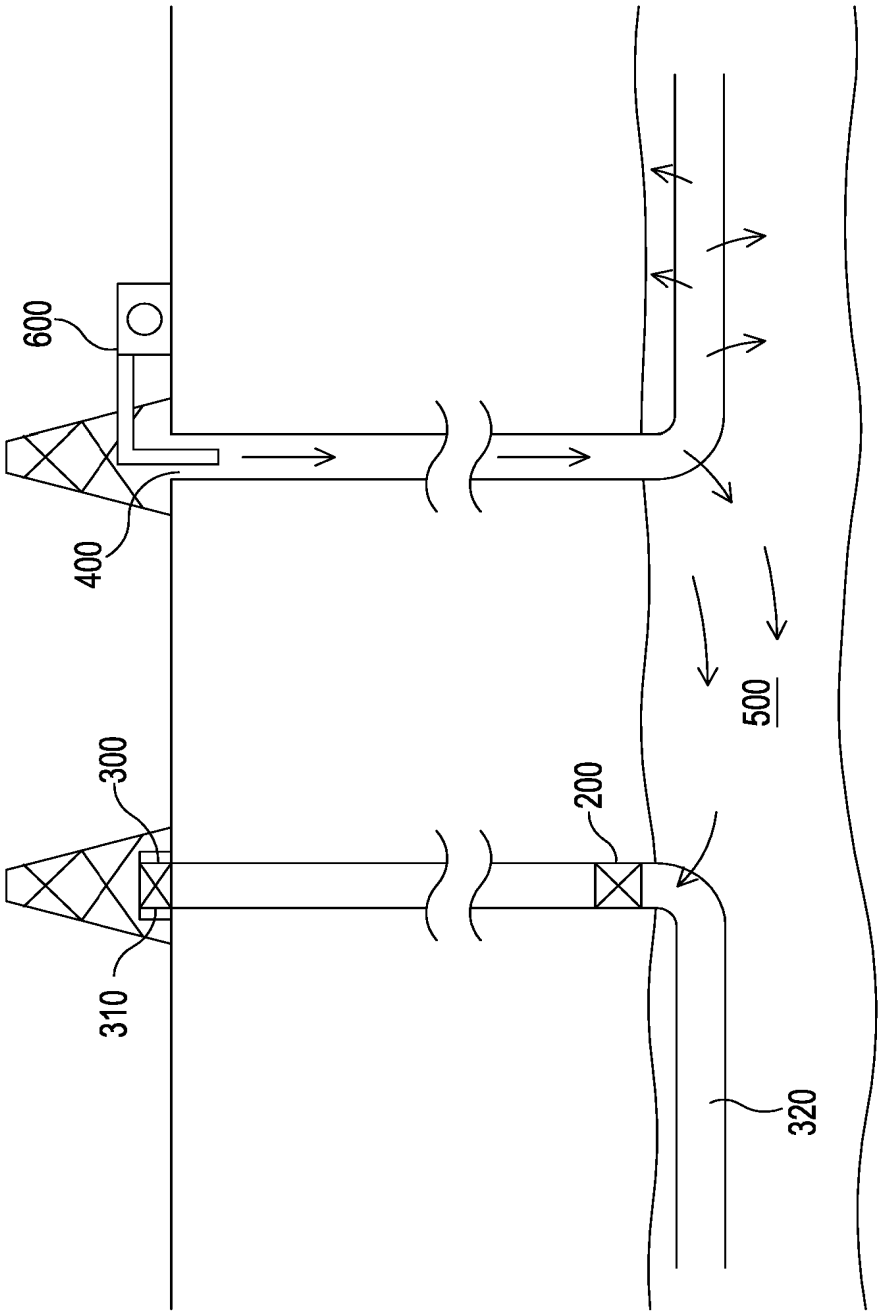


Figure 4

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Innovation, Science and Economic Development Canada
Canadian Intellectual Property Office

CA 3018485 A1 2017/08/10

(21) 3 018 485

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(86) Date de dépôt PCT/PCT Filing Date: 2017/02/06
(87) Date publication PCT/PCT Publication Date: 2017/08/10
(85) Entrée phase nationale/National Entry: 2018/09/20
(86) N° demande PCT/PCT Application No.: US 2017/016736
(87) N° publication PCT/PCT Publication No.: 2017/136841
(30) Priorités/Priorities: 2016/02/05 (US62/291,616); 2017/02/03 (US15/424,669)

(51) Cl.Int./Int.Cl. *E21B 43/26* (2006.01)
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(54) Titre : SYSTEMES ET PROCEDES D'ENTRETIEN DE PUITS A DISTANCE
(54) Title: REMOTE WELL SERVICING SYSTEMS AND METHODS

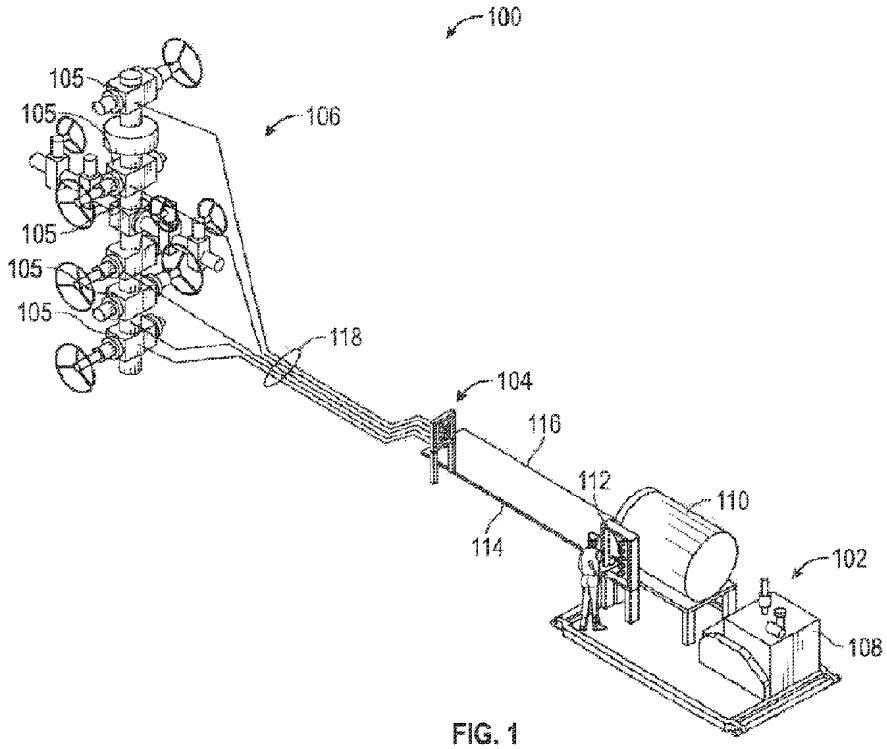


FIG. 1

(57) Abrégé/Abstract:
Embodiments of the present disclosure include a remote well servicing system including a control unit 102 and a remote servicing manifold 104. The control unit 102 further includes a service fluid source 110 and a control system 108. The remote servicing manifold 104 further includes a fluid input line 114 coupled to the service fluid source 110, a fluid output line 118 couplable to a well component 105, and a valve coupled to the fluid input line 114 and the fluid output line 118, wherein the valve, when actuated, places the fluid input line in fluid communication with the fluid output line and permits delivery of a service fluid from the service fluid source 110 to the well component 105. The remote servicing manifold 104 also includes a control line coupling the valve and the control system, wherein the control system controls actuation of the valve via the control line.

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
10 August 2017 (10.08.2017)

WIPO | PCT

(10) International Publication Number
WO 2017/136841 A1

(51) International Patent Classification:
E21B 43/26 (2006.01)

(21) International Application Number:
PCT/US2017/016736

(22) International Filing Date:
6 February 2017 (06.02.2017)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
62/291,616 5 February 2016 (05.02.2016) US
15/424,669 3 February 2017 (03.02.2017) US

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(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DJ, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KH, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

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(54) Title: REMOTE WELL SERVICING SYSTEMS AND METHODS

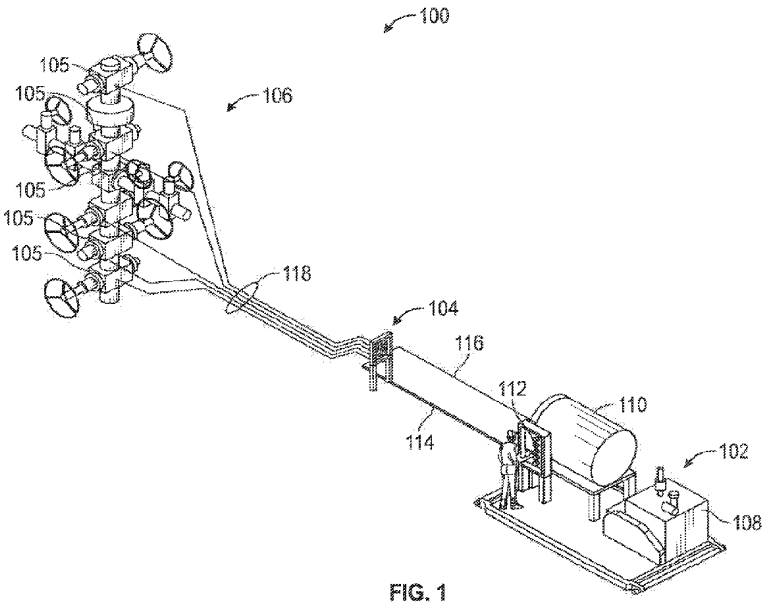


FIG. 1

(57) Abstract: Embodiments of the present disclosure include a remote well servicing system including a control unit 102 and a remote servicing manifold 104. The control unit 102 further includes a service fluid source 110 and a control system 108. The remote servicing manifold 104 further includes a fluid input line 114 coupled to the service fluid source 110, a fluid output line 118 couplable to a well component 105, and a valve coupled to the fluid input line 114 and the fluid output line 118, wherein the valve, when actuated, places the fluid input line in fluid communication with the fluid output line and permits delivery of a service fluid from the service fluid source 110 to the well component 105. The remote servicing manifold 104 also includes a control line coupling the valve and the control system, wherein the control system controls actuation of the valve via the control line.

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Declarations under Rule 4.17:

— *as to applicant's entitlement to apply for and be granted a patent (Rule 4.17(ii))*

— *as to the applicant's entitlement to claim the priority of the earlier application (Rule 4.17(iii))*

Published:

— *with international search report (Art. 21(3))*

REMOTE WELL SERVICING SYSTEMS AND METHODS

RELATED APPLICATIONS

[0001] This application is related to and claims priority to U.S. Provisional Patent Application No. 62/291,616, which was filed on February 5, 2016. This application is a continuation-in-part of U.S. Patent Application No. 14/725,341, which was filed on May 29, 2015. The full disclosure of these related applications are hereby incorporated herein by reference in their entirety.

BACKGROUND

1. Field of the Invention

[0002] The present disclosure relates to servicing well equipment. More particularly, the present disclosure relates to systems and methods of remotely providing a service fluid to one or more well components via a remote servicing manifold.

2. Description of Related Art

[0003] Certain hydrocarbon production related operations, such as hydraulic fracturing, utilize well equipment that is made up of many parts. One example is a hydraulic fracturing tree, which has many valves. These valves may need to be greased or lubricated from time to time to ensure proper function and maximum operational life. Typically, this process is carried out manually by an operator at the well site. As such, the operator has to travel to the well site and manually make and break the valve fittings in order to grease the valve. This process is time consuming and costly.

SUMMARY

[0004] Applicants recognized the problems noted above herein and conceived and developed embodiments of systems and methods, according to the present disclosure, for remotely providing a service fluid to one or more well components via a remote servicing manifold.

[0005] In an embodiment, a remote well servicing system includes a remote servicing manifold, which includes a fluid input line couplable to a service fluid source, a fluid output line couplable to a well component, a valve coupled to the fluid input line and the fluid output line,

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wherein the valve, when actuated, places the fluid input line in fluid communication with the fluid output line and permits delivery of a service fluid from the service fluid source to the well component, and a control line coupled to and controlling actuation of the valve.

[0006] In another embodiment, a remote well servicing system includes a control unit and a remote servicing manifold. The control unit further includes a service fluid source and a control system. The remote servicing manifold further includes a fluid input line coupled to the service fluid source, a fluid output line couplable to a well component, and a valve coupled to the fluid input line and the fluid output line, wherein the valve, when actuated, places the fluid input line in fluid communication with the fluid output line and permits delivery of a service fluid from the service fluid source to the well component. The remote servicing manifold also includes a control line coupling the valve and the control system, wherein the control system controls actuation of the valve via the control line.

[0007] In another embodiment, a method of remotely servicing a well component includes supplying a service fluid to a remote servicing manifold, actuating a valve on the remote servicing manifold, thereby permitting flow of the service fluid, and delivering the service fluid from the remote servicing manifold to a well component.

BRIEF DESCRIPTION OF DRAWINGS

[0008] The foregoing aspects, features, and advantages of the present disclosure will be further appreciated when considered with reference to the following description of embodiments and accompanying drawings. In describing the embodiments of the disclosure illustrated in the appended drawings, specific terminology will be used for the sake of clarity. However, the disclosure is not intended to be limited to the specific terms used, and it is to be understood that each specific term includes equivalents that operate in a similar manner to accomplish a similar purpose.

[0009] FIG. 1 is a schematic view of a remote well servicing system, in accordance with example embodiments of the present disclosure.

[0010] FIG. 2 is a diagram representation of a remote well servicing system, in accordance with example embodiments of the present disclosure.

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[0011] FIG. 3A is a block diagram of a remote well servicing system with remote servicing manifolds having electro-pneumatic valve control, in accordance with example embodiments of the present disclosure.

[0012] FIG. 3B is a block diagram of a valve actuation system of the manifold of FIG. 3A, in accordance with example embodiments of the present disclosure.

[0013] FIG. 4A is a block diagram of a remote well servicing system with remote servicing manifolds having fully pneumatic valve control, in accordance with example embodiments of the present disclosure.

[0014] FIG. 4B is a block diagram of a valve actuation system of the manifold of FIG. 4A, in accordance with example embodiments of the present disclosure.

[0015] FIG. 5 is a block diagram of the remote well servicing system of FIG. 3A with the addition of a pressure boosting station at the manifolds, in accordance with example embodiments of the present disclosure.

[0016] FIG. 6 is a block diagram of the remote well servicing system of FIG. 4A with the addition of a pressure boosting station at the manifolds, in accordance with example embodiments of the present disclosure.

[0017] FIG. 7 is a block diagram of a remote well servicing system with pressure relief, in accordance with example embodiments of the present disclosure.

DETAILED DESCRIPTION

[0018] The foregoing aspects, features, and advantages of the present disclosure will be further appreciated when considered with reference to the following description of embodiments and accompanying drawings. In describing the embodiments of the disclosure illustrated in the appended drawings, specific terminology will be used for the sake of clarity. However, the disclosure is not intended to be limited to the specific terms used, and it is to be understood that each specific term includes equivalents that operate in a similar manner to accomplish a similar purpose.

[0019] When introducing elements of various embodiments of the present disclosure, the articles "a", "an", "the", and "said" are intended to mean that there are one or more of the

elements. The terms "comprising", "including", and "having" are intended to be inclusive and mean that there may be additional elements other than the listed elements. Any examples of operating parameters and/or environmental conditions are not exclusive of other parameters/conditions of the disclosed embodiments. Additionally, it should be understood that references to "one embodiment", "an embodiment", "certain embodiments", or "other embodiments" of the present disclosure are not intended to be interpreted as excluding the existence of additional embodiments that also incorporate the recited features. Furthermore, reference to terms such as "above", "below", "upper", "lower", "side", "front", "back", or other terms regarding orientation or direction are made with reference to the illustrated embodiments and are not intended to be limiting or exclude other orientations or directions.

[0020] Embodiments of the present disclosure include systems and methods for remotely monitoring and/or servicing a well, such as providing a service fluid without operator intervention at the well site. An example application of the present disclosure includes greasing well assemblies during hydrocarbon drilling and development operations, such as during hydraulic fracturing or when the wells are producing and under pressure. Doing so can reduce failures of the well assembly and the operation. The systems and techniques of the present disclosure may be used for a wide variety of wells and well operations, and is particularly advantageous for wells that are not easily accessible by operators, such as remote land wells, dry offshore wells, and unmanned platforms, where regular servicing can increase operational life.

[0021] FIG. 1 is a schematic view of a remote well servicing system 100, in accordance with an example embodiment of the present disclosure. The system 100 includes a control unit 102 and a remote servicing manifold 104. Generally, in many applications of the present disclosure, the manifold 104 selectively delivers a service fluid from the control unit 102 to one or more well components 105 of a well 106. The control unit 102 may include a control system 108 and a service fluid source 110. The control system 108 controls at least some aspects of the remote well servicing system 100. The service fluid source 110 may be any suitable type of vessel or reservoir for holding a service fluid. The service fluid may be any type of fluid that may be used to service a well component from time to time. For example, the service fluid source 110 may be a grease or lubricant storage container.

[0022] The control system 108 may include one or more processors and/or controllers for carrying out its control functions, including controlling the manifold 104. The control system 108 may also include a control panel 112 or interface through which an operator can interact with the control system 108, such as to input control commands or receive output information.

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The control panel 112 may be located on the control unit 102, as illustrated in FIG. 1. Alternatively, the control panel 112 can be a part of a remote controller such as a pendant controller or a digital controller. As an example, the control panel 112 can be configured for touch screen operations and allow for straightforward and intuitive operation of the remove servicing operation. The control panel 112 can communicate via wires or wirelessly. Non-exhaustive wireless examples include wireless internet or telemetry, radio, microwave, ultrasonic, or infrared. In some embodiments, the control panel 112 may include a tablet computer, smart phone, personal computer, and the like, that allow for interaction with the control system 112 at one or more offsite locations.

[0023] The control unit 102 may be in the form of a wheeled mobile operation center or grease skid. Additional equipment may be located on the control unit that facilitation other operations, such as hydraulic fracturing. The control unit 102 may also include various other system components and control capabilities used to operate and monitor well equipment. Such components may include accumulators, hydraulic, electric, and pneumatic actuators, torque wrenches, pressure pumps, and various meters and visual indicators. Such components may be used to perform certain services at the well 106, such as diagnostic operations, as well as measuring temperature, pressure, oil and gas ratio, water content, and chemical tracers at the well 106.

[0024] The remote servicing manifold 104 is located away from the control unit 102. For example, in some applications, the manifold 104 is located twenty-five to one hundred feet from the control unit 102. However, in other example applications, the manifold 104 may be closer to or farther from the control unit 102. The manifold 104 includes a fluid input for receiving a service fluid and a control input for receiving a control signal. In some example embodiments, the fluid input is coupled to the service fluid source 110 at the control unit 102 via a supply line 114 and service fluid is delivered to the manifold 104 from the service fluid source 110 through the supply line 114. There may be a check valve coupled to the supply line 114 to prevent back flow. In some embodiments, the control input is coupled to the control system 108 at the control unit 102 via one or more control lines 116. The control lines 116 may include electrical lines, optical lines, pneumatic lines, and the like, and any combination thereof.

[0025] The manifold 104 includes one or more fluid outputs from which the service fluid can be delivered to one or more well components 105 through respective delivery lines 116. There may be one or more check valves coupled to the delivery line 116 to prevent back flow. In certain example applications, the manifold 104 may be located five to fifty feet away from the

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well 106. However, in some other example applications, the manifold 104 may be located closer to or farther from the well 106. The control system 108 controls delivery of service fluid from the manifold to each of the well components 105 by selectively actuating respective valves within the manifold via the control lines 116. Delivery of service fluid to each of the well components 105 may be independently controlled. Alternatively, service fluid may be delivered to all or a subset of the well components simultaneously.

[0026] FIG. 2 is a diagram representation of a remote well servicing system 200, according to example embodiments of the present application. In one or more such embodiments, the system 200 includes a control unit 202 and a plurality of remote servicing manifolds 204. The control unit 202 supplies service fluid to the manifolds 204 via supply lines 214 and controls the manifolds 204 via control lines 216. There may be control lines 216 and supply lines 214 connecting the control unit 202 directly to each manifold 204. Alternatively or additionally, there may be control lines 216 and/or supply lines 214 between manifolds 204. In such embodiments, service fluid and/or control signals may be communicated to one of the manifolds 204 via another manifold 204 rather than directly from the control unit 202. For example, such a configuration may be advantageous in an application where one manifold 204 is physically located between the control unit 202 and another manifold 204. Delivering control signals and/or service fluid to the farther manifold 204 via the closer manifold 204 rather than directly from the control unit 204 may reduce the number or length of lines required.

[0027] In the embodiment illustrated in FIG. 2, a manifold 204 can provide service fluid to a plurality of well components 205 on the same well 206 as well as to well components on a plurality of wells 206, as represented by each individual supply line 218. Additionally, one well 206 may receive service fluid from multiple manifolds 204. In some embodiments, the same service fluid may be provided to each of the manifolds 204. In some other embodiments, the control unit 202 may provide different types of services fluids to different manifolds 204. The control unit 202 may also provide different types of service fluids to the same manifold 204. This embodiment may be particularly useful for applications in which different well components require different service fluids.

[0028] FIG. 3A is a block diagram of a remote well servicing system 300, illustrating a control unit 302 coupled to three remote servicing manifolds 304 with electro-pneumatic valve control, which are coupled to three wells 306, respectively, in accordance with example embodiments of the present disclosure. The control unit 302 includes at least one service fluid source 310 and may include a pump 320 for pumping the service fluid from the fluid source 310

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to the manifolds 304. The service fluid is communicated from the control unit 302 to the manifold 304 via a supply line 314. The control unit 302 further includes an electrical controller 322 and a pneumatic source 324 that together control actuation of individual valves within the manifolds 304 that permit delivery of the service fluid to respective well components at the wells 306. The electrical controller 322 delivers electrical control signals to the manifold 304 via an electrical control line 316a and the pneumatic source delivers an air supply to the manifold 304 via a pneumatic control line 316b. Based on actuation of the valves in the manifolds, service fluid is selectively delivered to respective well components via fluid delivery lines 318. Thus, an operator or program can select to which well component(s) to provide service fluid. In some example embodiments, for each well component to which the manifold 304 provides service fluid, the manifold 304 includes a valve actuation system 350, as illustrated in FIG. 3B.

[0029] With reference to FIG. 3B, the valve actuation system 350 includes an electrical actuator such as a solenoid 326 which is controlled by an electrical signal from the electrical control line 316a. Upon actuation of the solenoid 326, a pneumatic actuator 328 receives air pressure from the pneumatic control line 316b and opens a valve, such as a needle valve 330. The needle valve is also coupled to the service fluid supply line 314 and the delivery line such that when open, the needle valve permits delivery of the service fluid to the well component 305. Alternatively, the needle valve 330 is coupled to a reservoir of service fluid within the manifold 304 and controls flow of service fluid from the reservoir to the well component 305 via the delivery line 318. In some embodiments, there is a valve actuation system 350 for every well component to which the manifold 304 is configured to deliver service fluid. In some other embodiments, one valve actuation system 350 may be configured to deliver service fluid to multiple well components 305 simultaneously.

[0030] FIG. 4A is a block diagram of a remote well servicing system 400, illustrating a control unit 402, three remote servicing manifolds 404 with fully pneumatic valve control, and three wells 406, in accordance with example embodiments of the present disclosure. The control unit 402 includes at least one service fluid source 410 and may include a pump 420 for pumping the service fluid from the fluid source 410 to the manifolds 404. The service fluid is communicated from the control unit 402 to the manifold 404 via a supply line 414. The control unit 402 further includes a pneumatic controller 424 that controls actuation of valves within the manifolds 404 by sending pneumatic signals through pneumatic control lines 416. Based on actuation of the valves in the manifolds, service fluid is selectively delivered to well components via respective fluid delivery lines 418. Thus, an operator or program can select which well

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component(s) to provide service fluid to. In some embodiments, the manifold includes a valve actuation system 450 for each well component 405 to which the manifold 404 provides service fluid, as illustrated in FIG. 4B, in accordance in one or more embodiments. In one or more embodiments, the valve actuation system 450 includes a pneumatically valve 430 that is coupled to the delivery line 418 and permits flow of service fluid to the well component through the delivery line 418 upon actuation. The valve 430 can be selectively actuated via the pneumatic control line 416 to permit fluid communication between the supply line 414 and the delivery line 418 to deliver the service fluid to the well component 405. In some embodiments, there is a valve actuation system 450 for every well component 405 to which the manifold 504 is configured to deliver service fluid. In some other embodiments, one valve actuation system 450 may be configured to deliver service fluid to multiple well components 405 simultaneously.

[0031] FIG. 5 is a block diagram of a another embodiment of a remote well servicing system 500 similar to the remote well servicing system 300 of FIG. 3, with the addition of a pressure boosting station 560 at the manifold 504. The pressure boosting station 560 increases the pressure of the service fluid in the delivery line 518 to facilitate delivery of the service fluid to the well 506. The pressure boosting station may include a well service fluid reservoir 562 with a pump 564 such that the service fluid can be pumped through the delivery line 518 at a sufficient pressure to ensure delivery of the service fluid to the well. This may be particularly advantageous in application in which there is wellbore pressure acting against delivery of the service fluid or if the well 506 is at a great distance from or a higher altitude than the manifold 504. Similarly, FIG. 6 is a block diagram of a another embodiment of a remote well servicing system 600 similar to the remote well servicing system 400 of FIG. 4, with the addition of a pressure boosting station 660 at the manifold 604.

[0032] FIG. 7 is a block diagram of a remote well servicing system 700 with pressure relief, in accordance with example embodiments of the present disclosure. The well servicing system 700 includes a control unit 702 which provides service fluid to a remote servicing manifold 704 via a supply line 714 and also controls a pneumatic valve in the manifold via a pneumatic control line 716. The manifold 704 then delivers the service fluid to a well 706 via a delivery line upon actuation of the pneumatic valve. During operation, it may be the case there is a high pressure trapped within the pneumatic control line 716, the supply line 714, or the delivery line 718, such as after closing the valve after a servicing process. As such, bleed lines 770 may be coupled to the pneumatic control line 716, the supply line 714, and/or the delivery line 718. These may be multiple individual bleed lines 770 or one joined bleed line 770. In certain embodiments, the

bleed lines 770 are each coupled to a relief valve 772 that can be used to control release of pressure in the respective lines 714, 716, 718. The bleed lines 770 may empty into a collection tank for disposal. In some embodiments, the relief valves 772 may be controlled automatically based on a predetermined protocol such when pressure within a respective line exceeds a certain threshold. Specifically, this may be carried out electronically using a pressure sensor and controller that reads the pressure sensor and controls the relief valve 772 accordingly. This may also be carried out purely mechanically by using a relief valve 772 that is configured to trigger open upon being subject to a certain set-point pressure. Alternatively, the relief valves 772 can be controlled remotely or manually by an operator when needed.

[0033] Embodiments of the present disclosure provide a remote well servicing system that allows for servicing of well components, such as applying a servicing fluid, to be carried out without interrupting other well operations or the need to assemble or disassembly any equipment, and without on-site operator intervention.

[0034] The foregoing disclosure and description of the disclosed embodiments is illustrative and explanatory of the embodiments of the invention. Various changes in the details of the illustrated embodiments can be made within the scope of the appended claims without departing from the true spirit of the disclosure. The embodiments of the present disclosure should only be limited by the following claims and their legal equivalents.

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CLAIMS

1. A remote well servicing system, comprising:

a remote servicing manifold, comprising:

a fluid input line couplable to a service fluid source;

a fluid output line couplable to a well component;

a valve coupled to the fluid input line and the fluid output line, wherein the valve, when actuated, places the fluid input line in fluid communication with the fluid output line and permits delivery of a service fluid from the service fluid source to the well component; and

a control line coupled to and controlling actuation of the valve.

2. The system of claim 1, wherein the control line comprises a pneumatic control line.

3. The system of claim 1, wherein the control line comprises a pneumatic control line and an electrical control line, and the control line controls actuation of the valve via a solenoid and a pneumatic actuator.

4. The system of claim 1, where the remote servicing manifold further comprises a pressure booster that increases the pressure in the fluid output line.

5. The system of claim 1, wherein the remote servicing manifold comprises a plurality of the fluid output lines, each couplable to a unique well component and communicative with the fluid input line via a unique valve.

6. The system of claim 1, wherein the remote servicing manifold is coupled to a bleed line, wherein service fluid in the remote service manifold, the fluid input line, and/or the fluid output line, is selectively directed into the bleed line to relieve pressure.

7. The system of claim 2, wherein the pneumatic control line is selectively coupled to a pneumatic bleed line to relieve pressure.

8. The system of claim 1, wherein the service fluid comprises a grease or a lubricant.

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9. The system of claim 1, further comprising a controller that controls the valve via the control line, and wherein the controller is remotely or wirelessly located from the remote servicing manifold.

10. The system of claim 1, further comprising a controller that automatically controls the valve via the control line based on a predetermined condition.

11. A remote well servicing system, comprising:

a control unit, comprising:

a service fluid source; and

a control system;

a remote servicing manifold, comprising:

a fluid input line coupled to the service fluid source;

a fluid output line couplable to a well component;

a valve coupled to the fluid input line and the fluid output line, wherein the valve, when actuated, places the fluid input line in fluid communication with the fluid output line and permits delivery of a service fluid from the service fluid source to the well component; and

a control line coupling the valve and the control system, wherein the control system controls actuation of the valve via the control line.

12. The system of claim 11, further comprising a plurality of the remote service manifolds, each of which comprises a fluid input line coupled to the service fluid source at the control unit.

13. The system of claim 11, wherein the control system comprises a user interface.

14. The system of claim 11, wherein the remote servicing manifold comprises a plurality of the fluid output lines, each couplable to a unique well component and communicative with the fluid input line via a unique valve.

15. The system of claim 11, wherein the control system controls actuation of the valve based on a command received from a user device.

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16. A method of remotely servicing a well component, comprising:

supplying a service fluid to a remote servicing manifold;

remotely actuating a valve on the remote servicing manifold, thereby permitting flow of the service fluid; and

delivering the service fluid from the remote servicing manifold to a well component.

17. The method of claim 16, further comprising delivering the service fluid from the remote servicing manifold to a plurality of well components simultaneously.

18. The method of claim 16, wherein the service fluid is a greasing fluid or a lubricant.

19. The method of claim 16, further comprising actuating the valve electrically, pneumatically, or electro-pneumatically.

20. The method of claim 16, further comprising relieving pressure in the remote servicing manifold by permitting flow of the service fluid into a bleed line.

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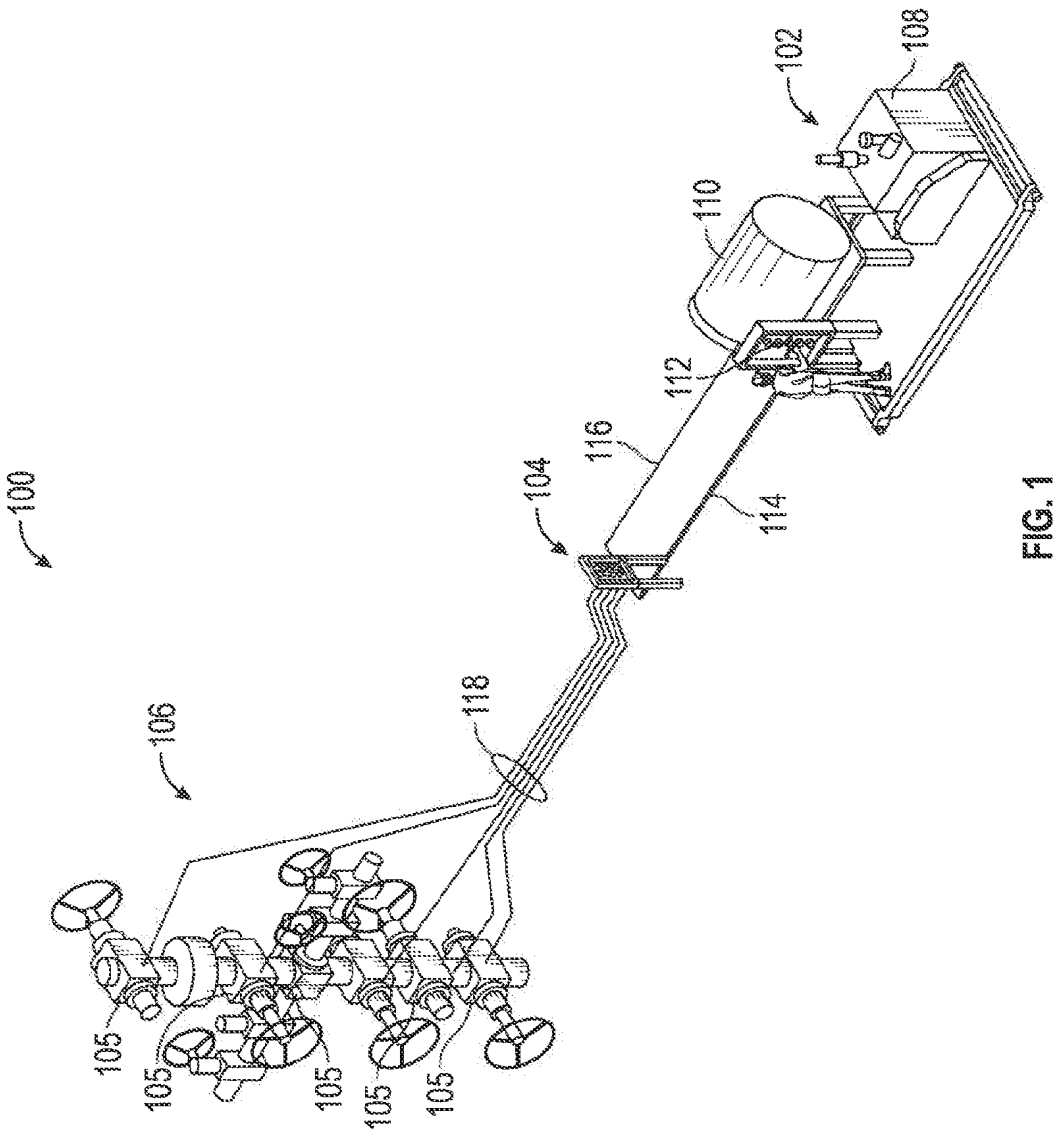


FIG. 1

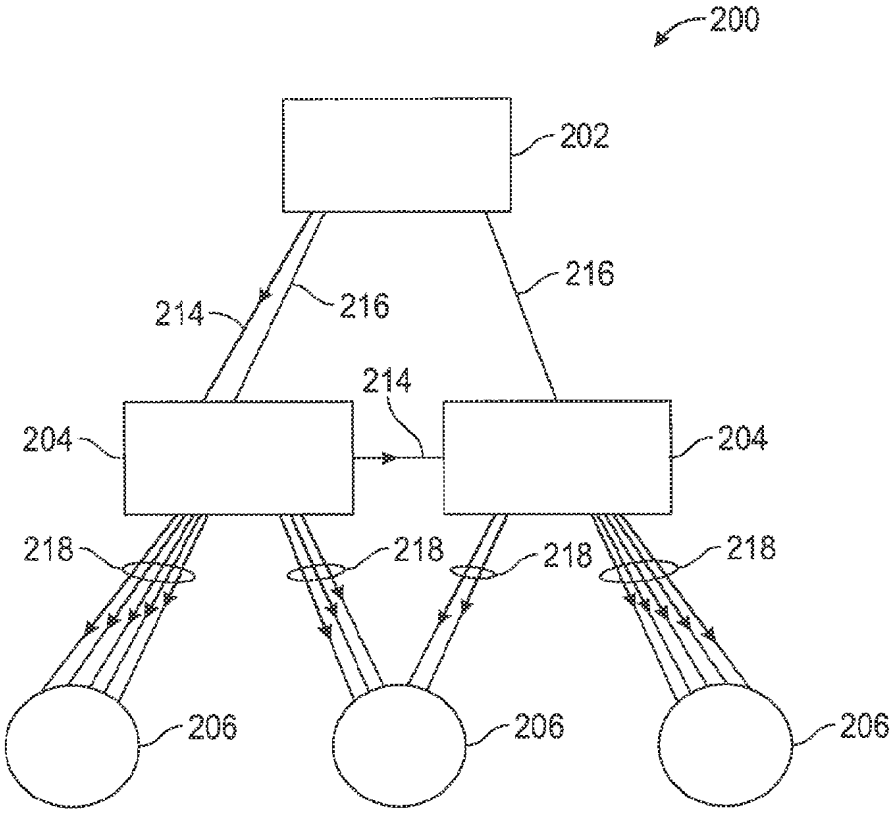


FIG. 2

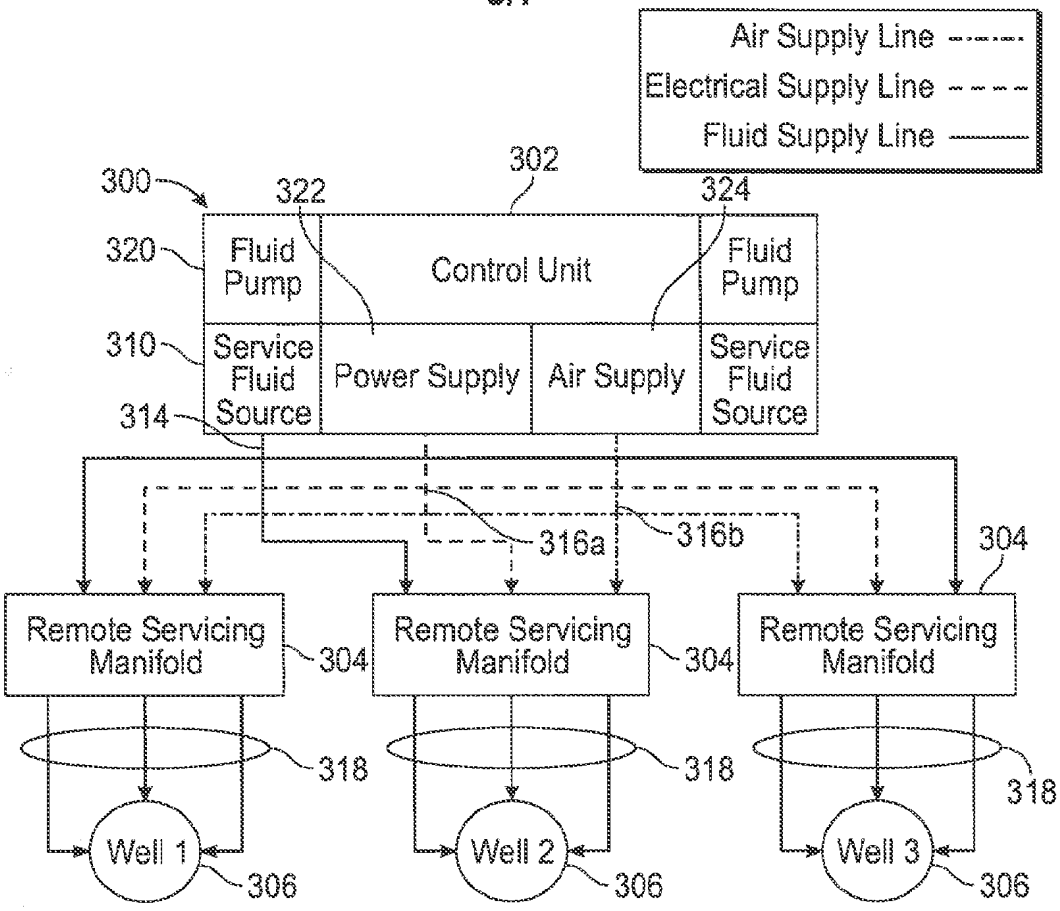

Air Supply Line
Electrical Supply Line
Fluid Supply Line
300
302
322
324
320
Fluid Pump
Control Unit
Fluid Pump
310
Service Fluid Source
Power Supply
Air Supply
Service Fluid Source
314
316a
316b
304
Remote Servicing Manifold
304
Remote Servicing Manifold
304
Remote Servicing Manifold
318
318
318
Well 1
306
Well 2
306
Well 3
306

FIG. 3A

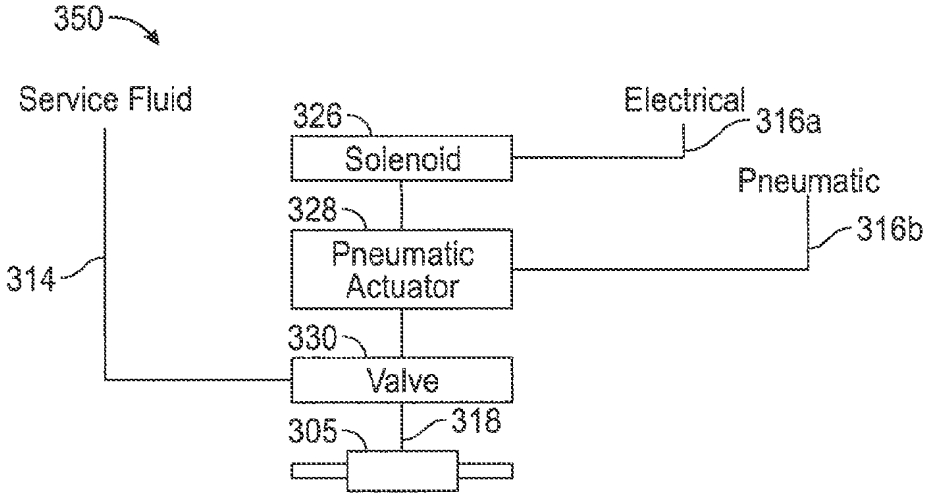

350
Service Fluid
326
Solenoid
Electrical
316a
Pneumatic
316b
328
Pneumatic Actuator
314
330
Valve
305
318

FIG. 3B

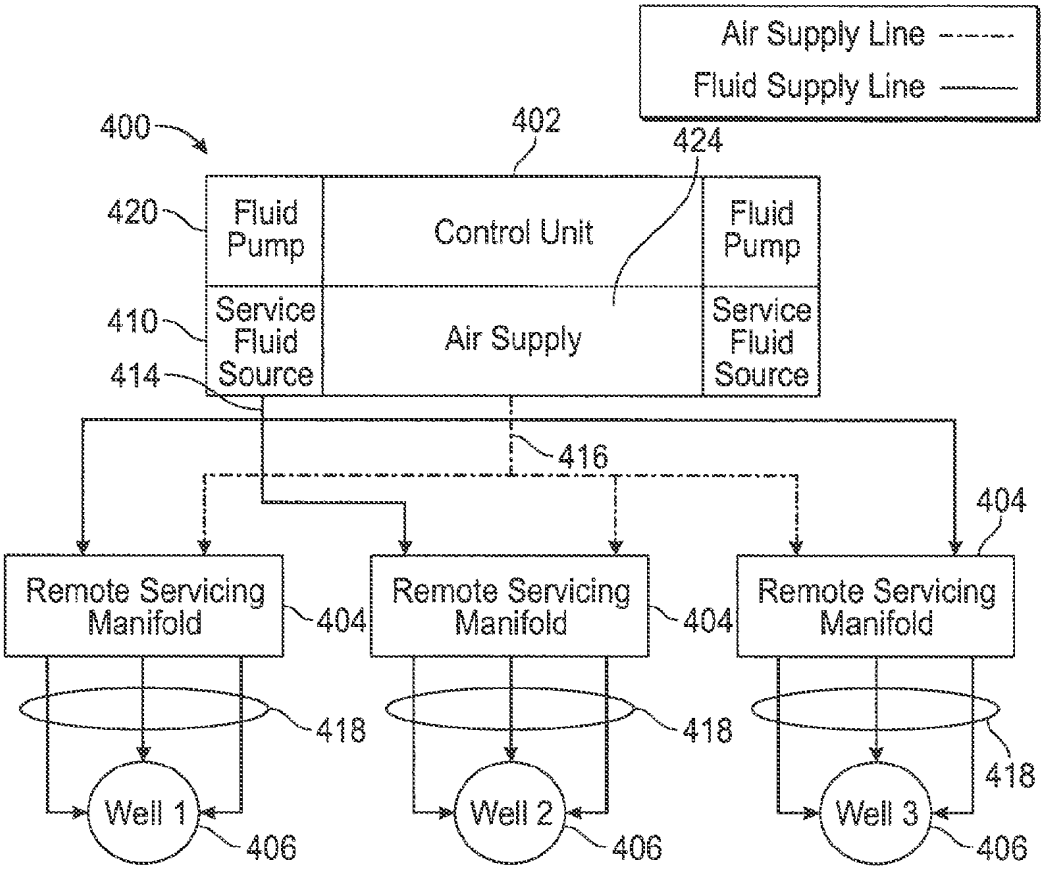

Air Supply Line
Fluid Supply Line
400
402
424
420
Fluid Pump
Control Unit
Fluid Pump
410
Service Fluid Source
Air Supply
Service Fluid Source
414
416
404
Remote Servicing Manifold
404
Remote Servicing Manifold
404
Remote Servicing Manifold
418
418
418
Well 1
406
Well 2
406
Well 3
406

FIG. 4A

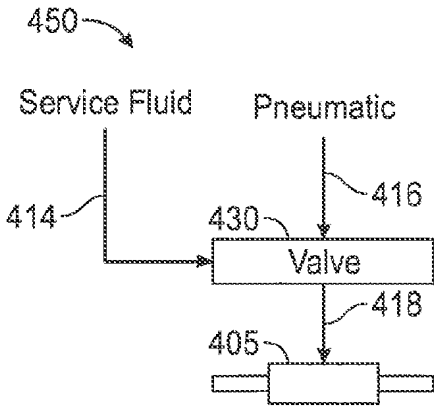

450
Service Fluid
Pneumatic
414
416
430
Valve
418
405

FIG. 4B

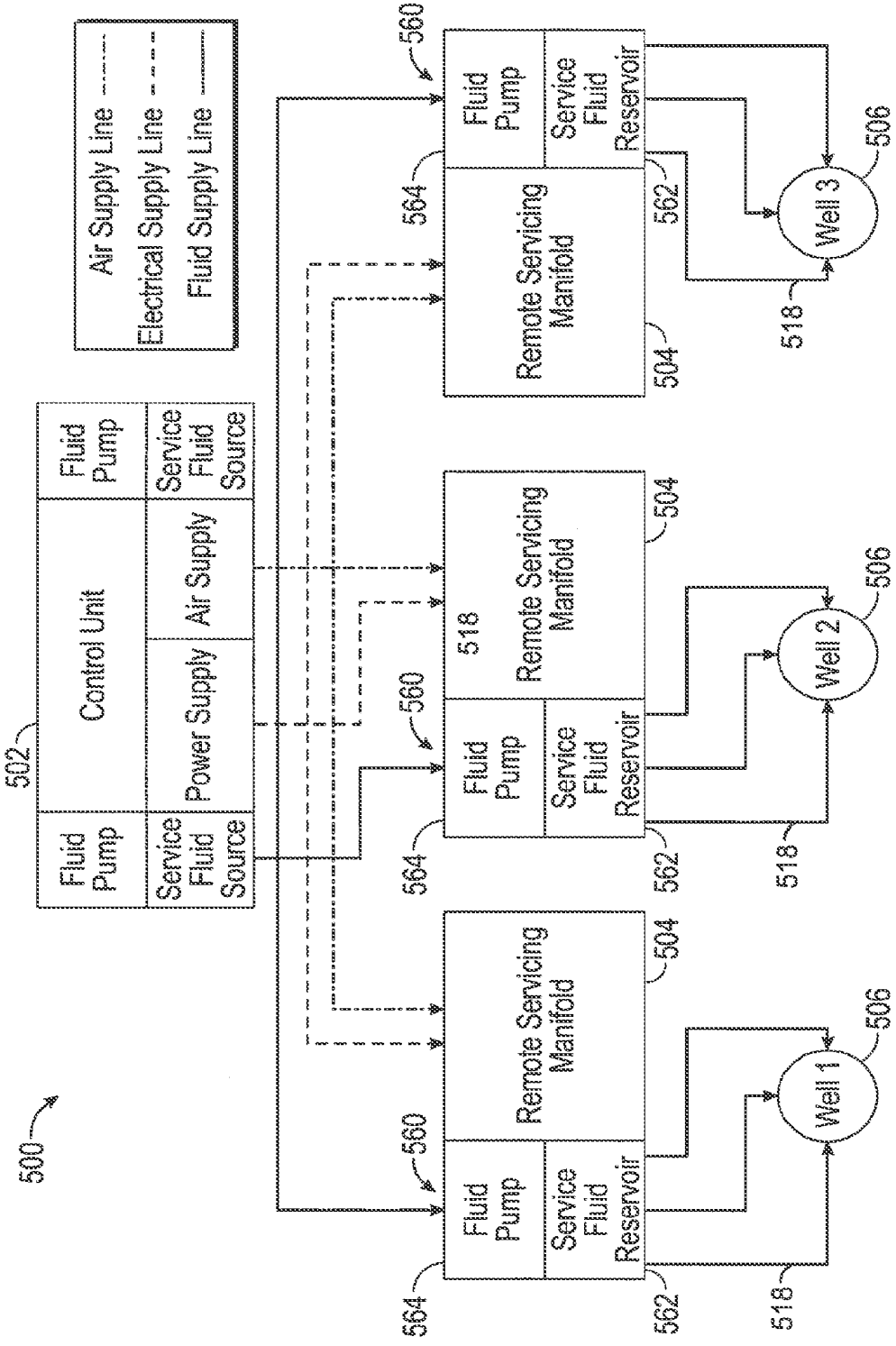


FIG. 5

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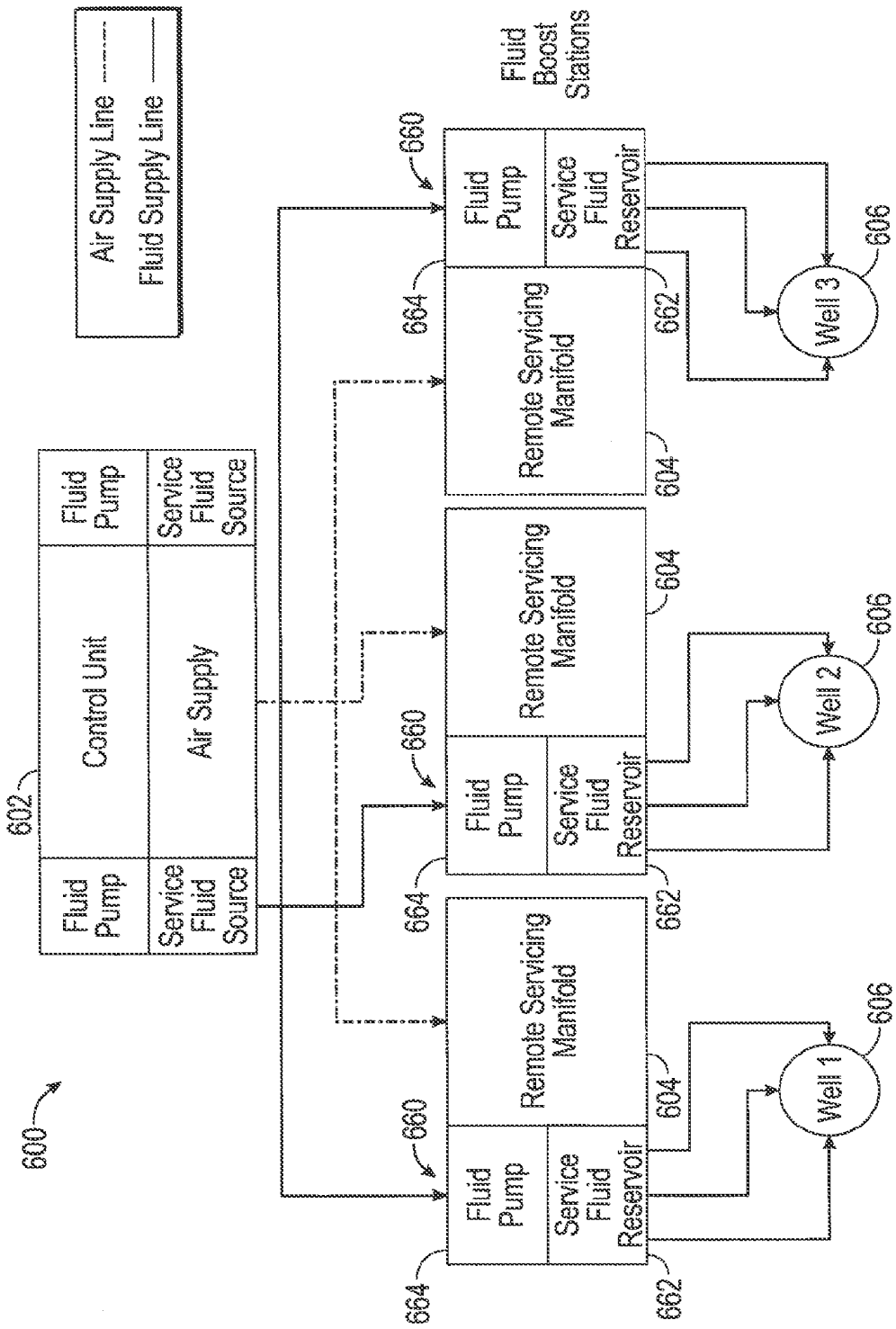


FIG. 6

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7/7

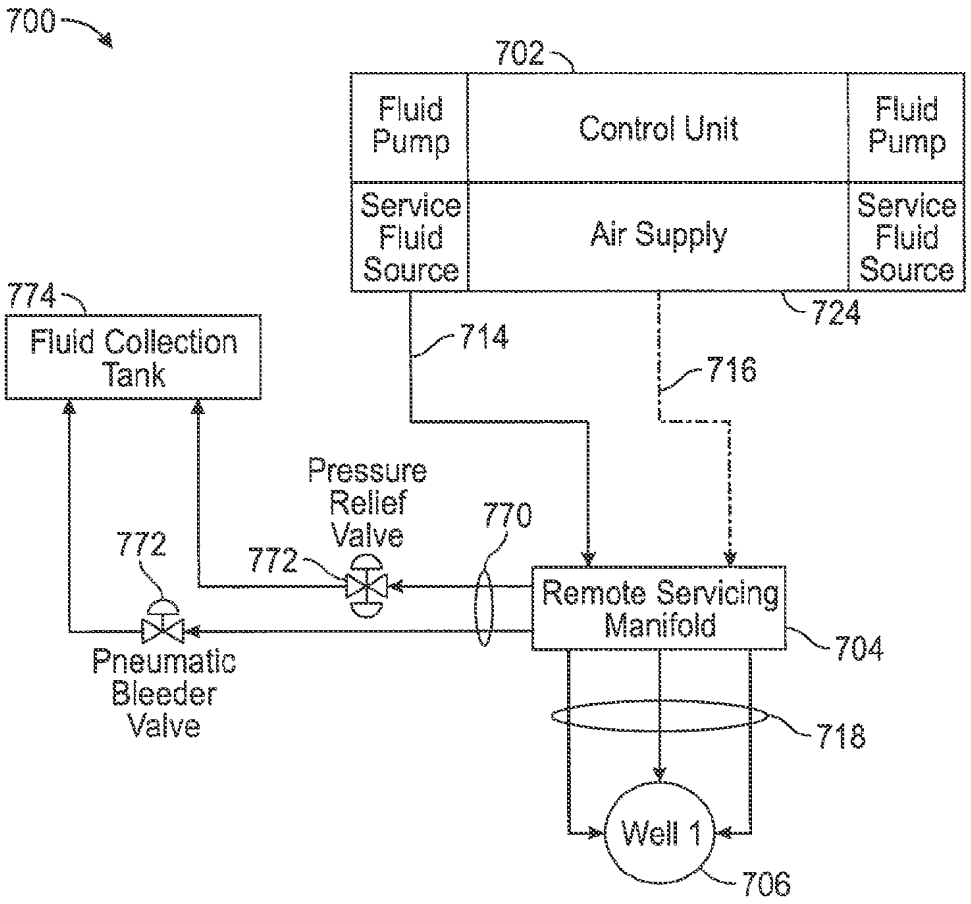

700
702
Fluid Pump
Control Unit
Fluid Pump
Service Fluid Source
Air Supply
Service Fluid Source
724
774
Fluid Collection Tank
714
716
Pressure Relief Valve
770
772
772
Remote Servicing Manifold
704
Pneumatic Bleeder Valve
718
Well 1
706

FIG. 7

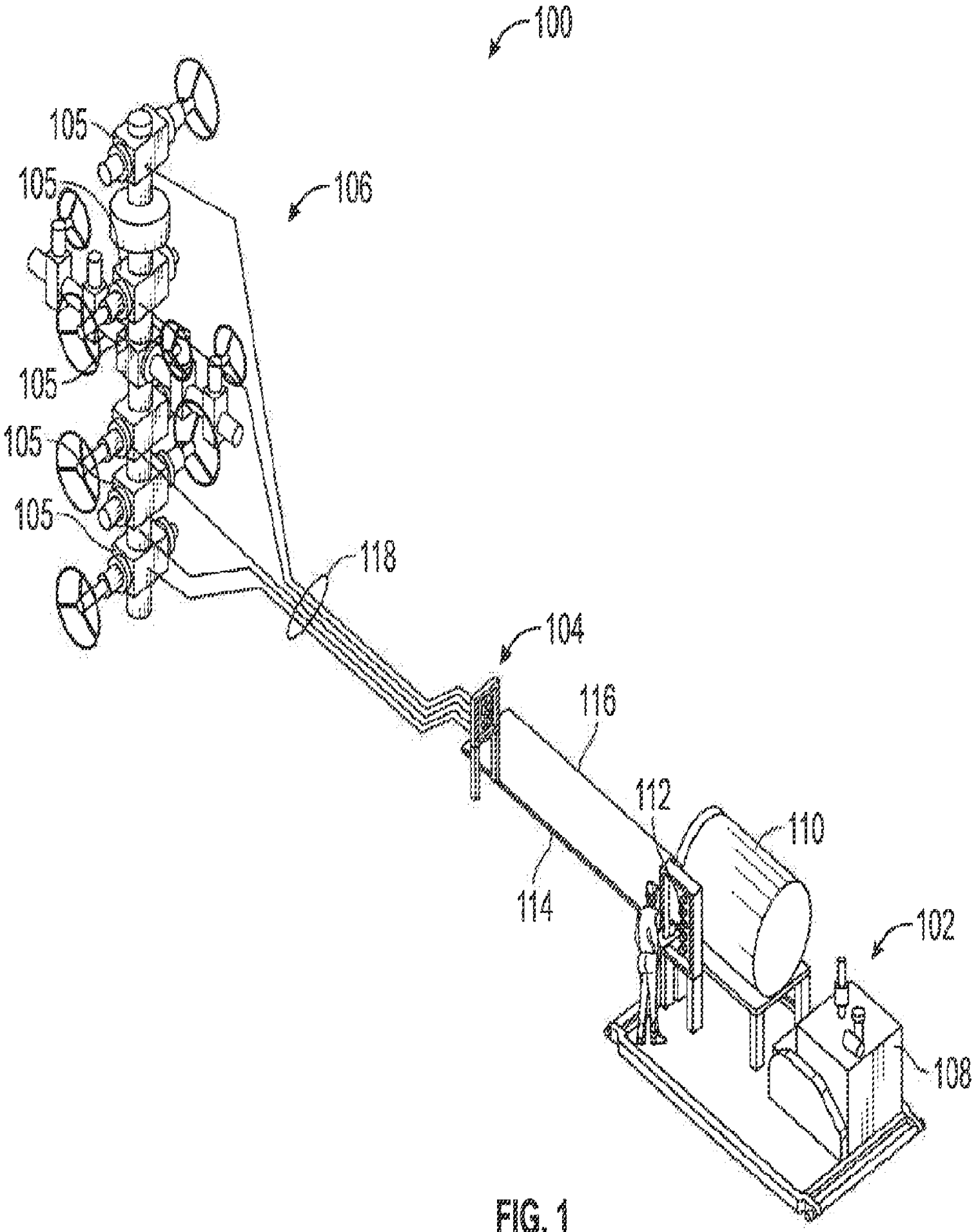


FIG. 1

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Innovation, Science and Economic Development Canada
Canadian Intellectual Property Office

CA 3050131 A1 2011/11/03

(21) 3 050 131

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) Date de dépôt/Filing Date: 2011/05/02

(41) Mise à la disp. pub./Open to Public Insp.: 2011/11/03

(62) Demande originale/Original Application: 2 797 081

(30) Priorité/Priority: 2010/04/30 (US61/330248)

(51) Cl.Int./Int.Cl. *G01M 13/00* (2019.01), *E21B 41/00* (2006.01), *E21B 44/00* (2006.01), *G01D 21/00* (2006.01), *G06Q 10/00* (2012.01)

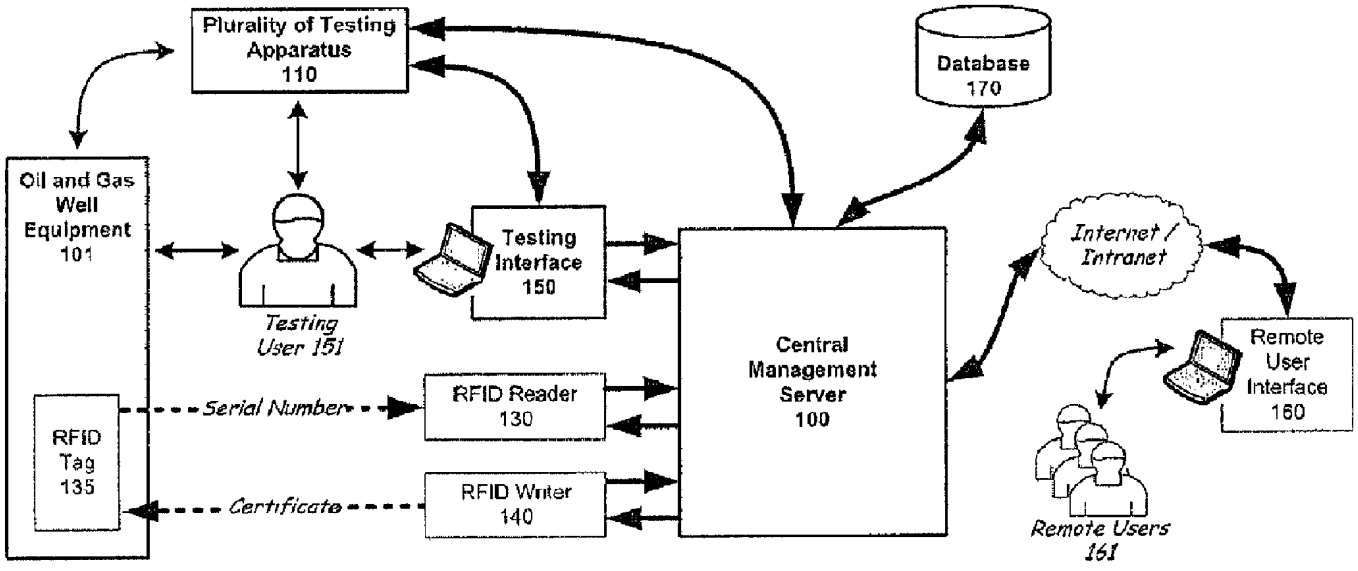
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(74) Agent: PERRY + CURRIER

(54) Titre : MACHINES, SYSTEMES, PROCEDES MIS EN OEUVRE PAR ORDINATEUR ET PRODUITS DE PROGRAMME INFORMATIQUE POUR TESTER ET CERTIFIER UN MATERIEL PETROLIER ET GAZIER

(54) Title: MACHINES, SYSTEMS, COMPUTER-IMPLEMENTED METHODS, AND COMPUTER PROGRAM PRODUCTS TO TEST AND CERTIFY OIL AND GAS EQUIPMENT



(57) Abrégé/Abstract:
Embodiments of machines, systems, computer-implemented methods, and computer program products certify oil and gas well equipment. Embodiments identify a selected well equipment device, a device test specification, and testing sequences to be performed by a corresponding testing apparatus. Embodiments select a testing sequence responsive to the selected device. Embodiments control the testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs

(21) 3 050 131

(13) A1

(57) **Abrégé(suite)/Abstract(continued):**
the sequence responsive to the device test specification. Embodiments generate testing data for the selected testing sequence and link the testing data for the selected testing sequence to the device identifier for the device so that a certificate can be generated. Embodiments generate a certificate for the selected device responsive to the testing sequences having been performed upon the selected device and link the certificate for the selected device to the device identifier so that the certificate can be readily recalled.

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ABSTRACT

Embodiments of machines, systems, computer-implemented methods, and computer program products certify oil and gas well equipment. Embodiments identify a selected well equipment device, a device test specification, and testing sequences to be performed by a corresponding testing apparatus. Embodiments select a testing sequence responsive to the selected device. Embodiments control the testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence responsive to the device test specification. Embodiments generate testing data for the selected testing sequence and link the testing data for the selected testing sequence to the device identifier for the device so that a certificate can be generated. Embodiments generate a certificate for the selected device responsive to the testing sequences having been performed upon the selected device and link the certificate for the selected device to the device identifier so that the certificate can be readily recalled.

MACHINES, SYSTEMS, COMPUTER-IMPLEMENTED METHODS, AND COMPUTER PROGRAM PRODUCTS TO TEST AND CERTIFY OIL AND GAS EQUIPMENT

Related Applications

[0001] This application claims priority and is related to U.S. Provisional Patent Application No. 61/330,248 filed April 30, 2010 titled "**Machines, Systems, Computer-Implemented Methods, And Computer Program Products To Test And Certify Oil And Gas Equipment,**" which is incorporated by reference in its entirety herein.

Field of the Invention

[0002] The present invention relates to oil and gas production. In more particular aspects, the present invention relates to testing and certification of equipment used in oil and gas production.

Background of the Invention

[0003] The production of oil and gas requires specialized well equipment, such as pipes, valves, joints, and fittings that operate in extreme conditions, including, for example, high pressure, temperature, volatility, and corrosivity. Such conditions promote the rapid wear of well equipment and increase the potential for failure. Moreover, when well equipment does fail, the impact of the failure is typically catastrophic. For example, the failure of well equipment can result in massive explosions that hurt workers, destroy property, and halt operations for a significant time—potentially costing millions of dollars in liabilities, repairs, and lost revenue.

[0004] Well equipment particularly susceptible to catastrophic failure includes, for example, the equipment used in the process of hydraulic fracturing known as "fracing" or "fracking." The process of fracing creates or extends fractures in subterranean rock formations by pumping fluid into the formation at high pressure. For example, fluid-driven fractures can be formed at the borehole in a drilling operation and then "grown" or extended into the rock formations. The injected fluid may contain "proppant" particles, such as grains of sand or ceramic, to lodge in the

fractures thereby keeping them open. Fracing is used to improve the rate at which oil and gas can be produced from a reservoir, and fracing is especially useful for extracting oil and gas from formations having low porosity and permeability, such as shale rock and other formations deep below the earth's surface. The equipment used in hydraulic fracturing for oil and gas wells can include, for example, a slurry blender, high pressure/volume fracturing pumps, high pressure treating iron, and other pipes, joints, valves, and fittings, which are known as "frac iron" or, simply, "iron." For example, frac iron can include swivel joints, pup joints, plug valves, check valves and relief valves.

[0005] To mitigate the likelihood and impact of their failure, frac iron must be periodically inspected and recertified according to certain specifications, which can be provided by, for example, a manufacturer or operator of the frac iron. Because of the likelihood and impact of failure, inspections can be performed as frequently as every 90 days. Inspections and recertifications typically require several different test procedures, which may include, for example, a visual check of bores, connections, seal surfaces; wall thickness measurements to check for erosion or corrosion, for example, using ultrasonic measurement; crack tests, for example, using magnetic particle measurement; and pressure tests, for example, of over 20,000 pounds per square inch (PSI).

[0006] Previously known methods to certify frac iron were lengthy and laborious, often lasting one to three weeks and requiring a human tester to control all testing, to record the results manually, and later to enter the results into a database—costing valuable production capacity due to downtime.

[0007] Also, previously known methods to certify frac iron were susceptible to inconsistencies due to the manually intensive nature of the certification, such as inconsistent performance of testing operations and inconsistent adherence to prescribed test specifications. Also, for example, certification records were created by manual input, introducing human error and recording and measurement variances into the certification records.

[0008] Also, previously known methods to certify frac iron were susceptible to operational inefficiencies. For example, certification records were kept in hard copy, which did not allow on-site operators to readily access certifications while in the field, which may be a remote

location such as an offshore rig. Furthermore, certification records and the test results associated therewith could not be tracked, updated, or reported on from a central control center.

Summary of the Invention

[0009] Embodiments of the present invention provide systems, methods, and machines for testing and certifying well equipment that enhance testing management, certification management, field operations management, and asset management. For example, embodiments of the present invention increase efficiency in testing and certifying well equipment by providing a systematic solution to control testing operations. Also, embodiments of the present invention increase efficiency in testing and certifying well equipment by seamlessly generating, storing, and processing testing data immediately upon performance of the testing operations, allowing a user to view the testing data in real time. Also, embodiments of the present invention increase efficiency in testing and certifying well equipment by dynamically generating certificates and reports responsive to the testing data according to multiple formats or user criteria.

[0010] Furthermore, well equipment testing according to embodiments of the present invention benefit from an increased likelihood of effective and safe operation because embodiments of the present invention systematically ensuring that testers use the proper test specifications and perform all test operations according to defined test sequences. Also, well equipment tested according to embodiments of the present invention benefit from an increased likelihood of effective and safe operation because embodiments of the present invention systematically ensure that equipment that fail any test sequence according to defined testing specifications are scrapped in the system and are unable to proceed in further testing or operation. Also, well equipment testing according to embodiments of the present invention benefit from an increased likelihood of effective and safe operation because operational crews can more readily access certificates, including comprehensive testing and certification data, on-demand and on-site. Furthermore, manufacturers and suppliers of well equipment can benefit from embodiments of the present invention by enhancing research and development efforts with greater knowledge of real-world wear patterns and wear rates for well equipment devices.

[0011] In view of the foregoing, applicant has provided a machine to manage periodic testing and certification of well equipment devices, the testing and certification being facilitated by a

plurality of testing apparatus performing one or more testing operations upon the well equipment devices. The machine comprises a processor, a non-transitory memory, an input/output unit to communicate with the plurality of testing apparatus, a database positioned to match a device identifier to a well equipment device, a test specification, and a plurality of testing sequences. The machine also comprises a testing module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the testing module being operable by the processor, the testing module comprising a set of instructions that, when executed by the processor, cause the testing module to perform operations. The operations of the testing module include identifying a selected well equipment device, a device test specification, and a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations.

[0012] The operations of the testing module further include selecting a testing sequence of the plurality of testing sequences, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device.

[0013] The operations of the testing module further include controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification. The operations of the testing module further include generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations.

[0014] The operations of the testing module further include linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in the database so that a certificate can be generated responsive thereto; and

[0015] The machine also comprises a certification module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the certification module

being operable by the processor, the certification module comprising a set of instructions that, when executed by the processor, cause the certification module to perform certain operations.

[0016] The operations of the certification module include identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device.

[0017] The operations of the certification module further include generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been performed upon the selected well equipment device responsive to the device test specification.

[0018] The operations of the certification module further include linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in the database so that the certificate can be readily recalled from the database responsive to the device identifier.

[0019] Also in view of the foregoing, applicant has provided a system to certify oil and gas well equipment. The system comprises a plurality of devices to be used in well equipment to define a plurality of well equipment devices, each well equipment device of the plurality of well equipment devices having a device identifier associated therewith. The system further comprises a central management server positioned to identify a device test specification and a plurality of testing sequences for a selected well equipment device responsive to receiving a device identifier for the selected well equipment device, the device test specification and the plurality of testing sequences defining certification criteria for the well equipment device. The system further comprises a plurality of testing apparatus, each testing apparatus positioned to perform a testing sequence upon the well equipment device, the testing sequence being a sequence of testing operations, the sequence of testing operations being performed responsive to the device test specification. The system further comprises a plurality of controllers, each controller positioned to receive commands responsive to the certification criteria from the central management server and to control the plurality of testing apparatus performing the sequence of testing operations upon the selected well equipment device responsive to the device test specification. The system

further comprises a certificate generated responsive to the plurality of testing apparatus performing the plurality of testing sequences upon the well equipment device, the certificate indicating whether selected well equipment device has been tested according to the certification criteria within a pre-selected period of time.

[0020] Also in view of the foregoing, applicant has also provided a computer-implemented method to manage periodic testing of a plurality of well equipment devices, the testing being facilitated by a plurality of testing apparatus performing one or more testing operations upon the plurality of well equipment devices. The computer-implemented method comprises receiving a device identifier for a selected well equipment device of the plurality of well equipment devices. The computer-implemented method further comprises identifying the selected well equipment device, a device test specification, and plurality of testing sequences, the identifying operation being responsive to the receiving operation, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations. The computer-implemented method further comprises selecting a testing sequence of the plurality of testing sequences to define a selected testing sequence, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device. The computer-implemented method further comprises calibrating the corresponding testing apparatus for the selected testing sequence responsive to the device test specification. The computer-implemented method further comprises controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification. The computer-implemented method further comprises generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations. The computer-implemented method further comprises linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in a database so that a certificate can be generated responsive thereto.

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[0021] Also in view of the foregoing, applicant has also provided a computer program product to manage periodic testing of a plurality of well equipment devices. The computer program product can be stored in a memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the computer program product being operable by a processor. The computer program product comprises a set of instructions that, when executed by the processor, cause the testing module to perform certain operations. The operations performed by the computer program product includes identifying a selected well equipment device, a device test specification, and a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations. The operations performed by the computer program product further includes selecting a testing sequence of the plurality of testing sequences, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device. The operations performed by the computer program product further includes controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification. The operations performed by the computer program product further includes generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations. The operations performed by the computer program product further includes linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in the database so that a certificate can be generated responsive thereto. The operations performed by the computer program product further includes identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device. The operations performed by the computer program product further includes generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been

performed upon the selected well equipment device responsive to the device test specification. The operations performed by the computer program product further includes linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in the database so that the certificate can be readily recalled from the database responsive to the device identifier.

Brief Description of the Drawings

[0022] So that the manner in which the features and benefits of the invention, as well as others which will become apparent, may be understood in more detail, a more particular description of the invention briefly summarized above may be had by reference to the embodiments thereof which are illustrated in the appended drawings, which form a part of this specification. It is also to be noted, however, that the drawings illustrate only various embodiments of the invention and are therefore not to be considered limiting of the invention's scope as it may include other effective embodiments as well.

[0023] FIG. 1 is a schematic diagram illustrating exemplary data flows and interactions among components of a system to certify well equipment according to an embodiment of the present invention;

[0024] FIG. 2 is a schematic illustrating exemplary components and connections of a central management server to certify well equipment according to an embodiment of the present invention;

[0025] FIG. 3 is a flowchart illustrating exemplary program product logic and computer-implemented methods for certifying well equipment according to an embodiment of the present invention;

[0026] FIG. 4 is a database diagram illustrating exemplary data structures according to an embodiment of the present invention;

[0027] FIG. 5 is an exemplary certificate according to an embodiment of the present invention;

[0028] FIGs. 6-8 are flowcharts illustrating exemplary process flow according to embodiments of the present invention;

[0029] FIGs. 9-23 are exemplary testing interface displays according to embodiments of the present invention; and

[0030] FIGs. 24-25 are exemplary reporting interface displays according to embodiments of the present invention.

Detailed Description

[0031] The present invention will now be described more fully hereinafter with reference to the accompanying drawings, which illustrate various embodiments of the invention. This invention, however, may be embodied in many different forms and should not be construed as limited to the embodiments set forth herein. Rather, these embodiments are provided so that this disclosure will be thorough and complete, and will fully convey the scope of the invention to those skilled in the art. It is to be fully recognized that the different teachings of the various embodiments discussed below may be employed separately or in any suitable combination to produce desired results. The various characteristics mentioned above, as well as other features and characteristics described in more detail below, will be readily apparent to those skilled in the art upon reading the following detailed description of the various embodiments, and by referring to the accompanying drawings. In the drawings and description that follow, like parts are marked throughout the specification and drawings with the same reference numerals, respectively. The prime notation, if used, indicates similar elements in alternative embodiments. The drawings are not necessarily to scale. Certain features of the disclosure may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in the interest of clarity and conciseness.

[0032] Accordingly, embodiments of the present invention improve safety, effectiveness, and efficiency of operating well equipment by meeting the foregoing objectives to mitigate the likelihood and impact of the failure of such equipment. In embodiments of the present invention, "well equipment devices" includes the equipment and devices used in hydraulic fracturing for oil and gas wells, i.e. "high pressure hydraulic fracturing flow iron," "frac iron," or, simply, "iron."

Frac iron can include, for example, a slurry blender, high pressure/volume fracturing pumps, high pressure treating iron, and other pipes, joints, valves, and fittings. For example, frac iron can include swivel joints, pup joints, plug valves, check valves and relief valves. Furthermore, by way of example, frac iron can include any type of ball injector, crow's foot, air chamber, crossover, hose, pipes/piping, hose loop, ball injector tee body, tee, wye, lateral, ell, check valve, plug valve, wellhead adapter, swivel joint, plug, relief valve, densometer, cross, frac pump, or cement pump. Those skilled in the art will appreciate that embodiments of the present invention are not limited to uses related to in oil and gas wells, but, rather, embodiments of the present invention are applicable to processes for testing or certifying any industrial equipment or device, and at any stage in the lifespan of the equipment, including during or after manufacturing and before, during, or after use or ongoing operations.

[0033] FIG. 1 illustrates a central management server 100 for performing operations of a testing module 220 and a certification module 210. The central management server 100 is positioned to be in communication with a plurality of testing apparatus 110. The plurality of testing apparatus 110 is capable of performing testing operations on a selected well equipment device 101. The central management server 100 is positioned to systematically control the performing of testing operations upon the well equipment device 101, systematically record and process the results of such testing operations, and systematically generate a certificate responsive to such recording and processing. Embodiments of the present invention providing systems, methods, and machines to certify of well equipment and are further described herein with specific reference to the drawings.

Central Management Server 100

[0034] An embodiment of a central management server 100, as illustrated in FIG. 2, can be configured as a computer, a server, or a machine of distributed computers or servers that at least include non-transitory memory 240, program products 210, 220, and 230, a processor or processors 251, an input/output device or devices ("I/O") 252.

[0035] I/O 252 connects the central management server 100 to a database 170, a testing interface 150, and one or more testing apparatus 110 (although represented as one block, those of skill in the art will appreciate that a plurality of testing apparatus 110 may include one or more

links to the I/O) to thereby allow central management server 100 to send and receive commands and data. I/O 252 can be any I/O including, but not limited to a network card/controller connected by a PCI (Peripheral Component Interconnect) bus to the motherboard, or hardware built into the motherboard of the central management server 100 to connect same to the forgoing database, interface, and apparatus.

[0036] As those of skill in the art will appreciate, I/O 252 can connect the central management server 100 with any other compatible machine, server, system, device, or equipment having a suitable physical interface and that I/O 252 and/or computer program products 210, 220, and 230 on non-transitory memory 240 may be positioned to understand, convert, or translate application or communication protocols of such machines, servers, systems, devices, or equipment irrespective of native protocols. Also, one of skill in the art will understand that I/O 252 can include or otherwise incorporate any logical or physical technology necessary to effect a connection with any of the aforementioned devices, including, for example, hubs, switches, routers, converters, amplifiers, and wireless transceivers. For example, as is further described herein, I/O 252 can also connect the central management server 100 to devices for interacting with radio frequency identification (RFID) devices, such as an RFID reader or interrogator 130 and an RFID writer 140. The central management server 100 can further connect to a remote user interface 160 for interacting with a remote user 161, as is also discussed further herein. Also, the plurality of testing apparatus 110, RFID reader 130, and the RFID writer 140 may be configured as peripherals to the testing interface 150. Also, there a testing apparatus 110 interface 253, such as a programmable logic controller (PLC), an interface between the I/O 252 and the plurality of testing apparatus 110 to control the plurality of testing apparatus 110.

[0037] As can be seen in FIG. 2, the I/O 252 is connected to a processor 251. The processor 251 is the "brains" of the central management server, and as such executes program products 210, 220, and 230 and works in conjunction with the I/O 252 to direct data to the non-transitory memory 240 and to send data from the non-transitory memory 240 to the database 170, the testing interface 150, and one or more testing apparatus 110. The processor 251 can be any commercially available processor, or plurality of processors, adapted for use in or with the central management server 100, *e.g.*, Intel® Xeon® multicore processors, Intel® micro-

architecture Nehalem, and AMD Opteron™ multicore processors. As one skilled in the art will appreciate, processor 251 may also include components that allow the central management server 100 to be connected to a display, as will be understood by those skilled in the art, and keyboard or other peripherals that would allow a user to directly or indirectly access the processor 251 and non-transitory memory 240.

[0038] Non-transitory memory 240 stores computer program products 210, 220, and 230 having instructions for execution on the processor 251, and consists of both non-volatile memory, *e.g.*, hard disks, flash memory, optical disks, and the like, and volatile memory, *e.g.*, SRAM, DRAM, and SDRAM as required to support embodiments of the instant invention. As one skilled in the art will appreciate, though the non-transitory memory 240 is depicted on, *e.g.*, a motherboard, of the central management server 100, the non-transitory memory 240 may also be a separate component or device, *e.g.*, FLASH memory, connected to the central management server 100 through the I/O 252. The non-transitory memory 240 may also store applications that various workstations or remote units can access and run on the central management server 100. For example, a testing user 151 may access applications and computer program products stored on the non-transitory memory 240 and run on the processor 251 using the testing interface 150. Importantly, non-transitory memory 240 stores the program products 210, 220, and 230 of the instant invention. As one skilled in the art will understand, the program products 210, 220, and 230, along with one or more databases/tables/fields/records for data associated with the selected well equipment device 101 can be stored either in non-transitory memory 240 or in separate non-transitory memory associated, for example, with a storage medium such as database 170, positioned in communication with the central management server 100.

Database 170

[0039] As seen in FIG. 1 and FIG. 2, the database 170 is in communication with the central management server 100. Although the database 170 is illustrated according to an embodiment in which the database 170 is separate and distinct from the central management server 100, for example, as a database server, the present invention may also include any arrangement of the database 170 in communication with the central management server 100, including the database 170 being incorporated into the same computer, server, machine, or system constituting the

central management server 100, as one physical unit, for example, as an application or partition in the central management server 100 or as an installed component of the central management server 100 communicating with the processor 251 through the use of the I/O and having, for example, a database memory separate and distinct from memory 240, such as a hard drive, optical storage, or the like. Database 170, as is understood in the art, can include a processor directing data from a bus into the database memory, which can be, for example, a hard drive, optical storage or the like, and computer software that provides computers, including the central management server, access the data therein.

[0040] The database 170 can store therein a data structure or data structures relating to the well equipment devices 101 to be tested and all data generated during the execution of the testing module 211 and certification module 210, as is further discussed herein. In embodiments, database 170 is a relational database positioned to match data by using common data found between data sets, the data sets being organized according to tables 400, 410, 420, 430, 440, and 450 as seen in FIG. 4. As will be understood by those skilled in the art, FIG. 4 illustrates an exemplary set of data structures only, and there may be other unique table structures positioned to relate and match the data in manners commensurate with the embodiments of the present invention. Data stored in the database 170 may be updated as needed, for example, by a user with administrative access to the database to add new well equipment devices to the database as they become supported. As is described further herein with relation to the computer program products, database 170 can be positioned to store data in tables relating to the unique device tested 400, parts in a parts library 410, test specifications in a test specification library 420, test sequences in a test sequence library 430, test data in a test data repository 440, and certificate data in a certificate data repository 450. And as is described further herein, the database 170 is positioned to match common data appearing in the foregoing tables.

Testing Apparatus 110

[0041] As shown in FIG. 1 and FIG. 2, the plurality of testing apparatus 110 are in communication with the central management server 100. The plurality of testing apparatus 110 perform testing operations under the control of the central management server 110 and provide tools or devices to gather testing data 440 as shown in FIG. 4, *i.e.,* the data that serves as the

basis for the certification. In embodiments, the plurality of testing apparatus 110 at least includes an ultrasonic wall thickness meter ("UT meter") and a pressure test pump having a transducer. The plurality of testing apparatus 110 can include any other device or unit capable of being employed either manually or under automated control by the central management server 100 to interact with the well equipment device 101. Other testing apparatus 110 can include, for example, digital calipers. A local user may employ embodiments of the present invention, for example, by positioning the frac iron to be tested 101 in a testing station adapted for the test performed, and by manually configuring the frac iron 101 to safely and effectively interact with the testing apparatus 110 for the intended test.

[0042] Although shown as separate blocks in FIG. 1, the testing interface 150, which can be a personal computer (PC), can be connected to a peripheral testing apparatus 110 to control or collect data from a testing apparatus 110 connected as a peripheral to an input/output unit of the PC. The combination of the testing apparatus 110 and a PC may be referred to, collectively, as a testing apparatus 110. PC or testing interface 150 can connect to a peripheral testing apparatus 110 via any connection type known to those in the art, such as a Universal Serial Bus connection (USB), and such connection may include analog inputs and digital inputs, wired and wireless, and including analog-to-digital converters and amplifiers for digital inputs.

[0043] The plurality of testing apparatus 110 and a PC incorporated with a peripheral testing apparatus 110 can be a mobile unit or units having remote or wireless connectivity to central management server 100 using any protocols or standards known in the art, including Wi-Fi, GSM, and WIMAX, for example. Mobile units may also be synchronized with central management server through periodic wired or wireless connections when returning from field use. The PC can be, for example, any suitable PC known in the art and is preferably a Panasonic® Toughbook® or other portable, notebook, laptop, or tablet computer preferably designed to withstand vibration, drops, spills, extreme temperature, and other rough handling and conditions common to industrial use.

[0044] The UT meter can be, for example, an Olympus® MG2DL, or any similar UT meter known in the art. The UT meter can include, for example, features such as B-scan, gain adjust, auto sensitivity optimizations, echo-to-echo, differential mode, hi-low alarm, and live A-scan.

The UT meter can also include a file-based alphanumeric data logger and an interface program for transferring data bi-directionally to and from a PC. The testing apparatus 110 can include a PC, such as described above, for enabling data and control functions of a peripheral testing apparatus 110 such as a UT meter.

[0045] The pressure test pump and transducer can be any suitable pressure test pump known in the art. Preferably, embodiments of the invention employ an X45 series model 345 Viatran® test and control pressure sensor, which can, for example, operate in the range of 0-100,000 psi with output in the range of 4-20 mA. As is known in the art, the testing apparatus 110 can include a control interface such as a programmable logic controller (PLC) for communication with and control of the pressure test pump and transducer.

Testing User 151 and Testing Interface 150

[0046] As described above, a testing user 151 may employ embodiments of the present invention, for example, by positioning the frac iron to be tested 101 in a testing station adapted for the test to be performed, and will manually configure the frac iron 101 to safely and effectively interact with the testing apparatus 110 for the intended test. In other embodiments, the testing user may perform testing operations according to instructions provided by the central management server 110 and displayed, for example, on the testing interface 150. The testing user 151 may provide the means of manually gathering testing data 440 as shown in FIG. 4, *i.e.*, the data that serves as the basis for the certification. Testing operations, as described above with reference to the testing apparatus 110, may be systematic, manual, or hybrid systematic/manual. For example, a sequence of testing operations for testing wall thickness of the frac iron may include systematic test operations to be performed by a testing apparatus 110, such as a UT meter, and manual operations to be performed by a testing user 151, such as using digital calipers to measure wall thickness or other dimensions of the frac iron, as can be seen in FIGS. 15-16, for example. Likewise, other sequences of testing operations may be fully manual, such as the mag particle test discussed further herein.

[0047] Also as described above, the testing interface 150 may be a PC, which may be any desktop, laptop, notebook, tablet, or portable computer known to those in the art. As is known the art, the testing interface 150 can include any number of peripheral devices to interact with the

testing user 151, including a keyboard, mouse, control stick/joystick, and memory reader for receiving data input and a display screen, printer, and local storage device for outputting or storing data. Furthermore, embodiments of invention have a testing interface with a touch-sensitive screen (*e.g.,* using a stylus) for interactive display/input so that users can select parts responsive to viewing them on the display of the testing interface 150 and thereafter performing testing operations responsive to the selection, in communication with the testing module 210. The testing interface 150 may connect with the central management server 100 via any communications interface known to those of skill in the art, wired or wireless, and is preferably a secure local Intranet or other authenticated and encrypted communications network, including a VPN over the Internet.

Certificate 500

[0048] FIG. 5 sets forth an exemplary certificate 500 generated responsive to embodiments of the present invention. The certificate 500 relates to data stored in the database 170, for example, the certificate data 450 as shown in FIG. 4. The certificate 500, as is appreciated by those skilled in the art, can be a paper document printout or an electronic document in a format such as Adobe® Portable Document Format (.PDF), Microsoft® Word (.DOC or .DOCX), or a similar format. The certificate 500, for example, can be a paper document printout, as it is the custom in drilling and fracing operations for a paper document printout of a certificate to be presented to company personnel when well equipment is brought on-site in field operations. The company personnel takes possession of the physical document and reviews the testing parameters and testing results documented thereon to verify the quality of the equipment brought on site.

[0049] The certificate 500 can reference the well equipment device 101 by a unique device identifier, such as the serial number 501, which can relate to data stored in database 170 in the device information table 400. The certificate 500 can contain a summary indication as to whether certain test sequences were graded as a "PASS" or a "FAIL" 502. The grading operation, for example, can be performed by a certification module 220 computer program product operating on the central management server 100. The PASS or FAIL grading 502 can relate to data stored in the database 170, for example, the certificate data 450 and the testing data 440 shown in FIG. 4. The certificate 500 can also contain a summary or other rendering of

testing data responsive to testing operations being performed on the well equipment device 101, for example, a graphical representation of a pressure test 503. Graphical representation 503 can relate to data stored in the database 170 in the certificate data table 450 and the testing data table 440.

[0050] The certificate 500 can also contain a summary indication as to measured qualities of the selected well equipment device 101 and their relation to the qualities demanded by the test specification. For example, measured wall thickness value 505 appears adjacent to demanded wall thickness value 506. Additionally, drawing 504 shows a graphical representation of the parameters measured according to the test specification, as referenced by letter key (*e.g.*, "A," "B," and "C".).

[0051] In certain embodiments of the present invention, a certificate can be stored in a proprietary data table format so that a lightweight electronic copy of the certificate, and an "RFID certificate" can be stored directly onto RFID tag 135 attached to the selected well equipment 101. For example, as understood by those skilled in the art, the RFID certificate can be written to an RFID tag 135 attached to the well equipment so that the certificate can be readily accessed in the field using an RFID reader device 130 capable of recognizing the proprietary data table format. The RFID certificate can include all fields available on the paper certificate 500, including device identifier 501, pass or fail grading 502, tabular summary or rendering of test data 503, drawing 504, measured values 505, and demanded values 506. The tabular summary or rendering 503 and the drawing 504 can be encoded, for example, using lightweight vector-based primitive formats. Also, RFID certificate will allow new schemes for protecting certificate data heretofore unavailable for field use, for example, by having individual cells in the table that are protected according to user access schemes such as read-only, read-write, or no access. For example, the serial number and the certification may be read-only to all; the certificate data may be read-only to many and read-write to few; and custom fields may be user-configurable.

Testing Module 210

[0052] As is shown in FIG. 2, the testing module 210 may be a computer program product stored in the memory 240 on the central management server 100 and operable on the processor

251 thereof. Computer program product 210 contains instructions that are operable on the processor 251 that cause the testing module 210 and the central management server 100 to perform the operations discussed further herein.

[0053] The testing module 210 can interact with the processor to receive or transmit data, instructions, and other information from or to any of the devices connected to I/O 252. In embodiments discussed below, the testing module 210 at least interacts with the testing interface 150, testing apparatus 110, RFID reader 130, and database 170. Although testing interface 150 has been described to be a personal computer (PC), testing interface 150 can also be implemented in whole or in part as a user terminal interface on the central management server 100 itself, or using a keyboard, display, or media inputs and outputs connecting to the I/O 252. Testing interface 150 can also be a lightweight graphical user interface (GUI) operable over a web browser and viewable on any browser-enabled device, such as a PC, smart phone, or other equipment having a processor and computer functionality. Testing interface 150, for example, can receive user-selected identifiers or other user-selected values or parameters from a testing user as will be described in further detail below and can display identifiers, values, parameters, and other specification data, for example, as can be shown with reference to the selection, input, or display fields 900, 1000, 1100-1101, and 1200-1205 in FIGS. 9-12. Other user selection, input, or display fields are also shown elsewhere in FIGS. 13-25, as will be apparent to those having skill in the art.

[0054] The testing module 210 can receive a device identifier for a selected well equipment device 101, the selected well equipment device being a well equipment device positioned to undergo testing and certification, *i.e.,* in the testing warehouse, on a testing trailer, or otherwise positioned at a testing station. In the embodiment of the present invention, only one well equipment device is tested at any given time using any particular testing apparatus 110. It is possible, however, that multiple instances or threads of the testing module 210 can run on the processor 251 concurrently, with each instance being directed to the testing of a different piece of well equipment positioned for testing. It is also possible that multiple testing apparatus 110 of the same type may be employed to perform the same test sequence in simultaneous testing operations performed on multiple well equipment devices 101.

[0055] The testing module 210 can receive a serial number as a device identifier as shown in FIG. 6. The testing module 210 can receive a serial number as a device identifier, for example, by receiving input from the testing interface 150 as entered therein by a testing user 151. The testing module 210 can also receive a device identifier, such as a serial number, from a peripheral device, such as an RFID reader 130, as is discussed further herein.

[0056] The testing module 210 can identify the selected well equipment device responsive to the device identifier as shown in and match the selected well equipment to: (i) device library information as shown in FIG. 4 at table 400, the device library information including a part number, and (ii) a part library information at table 410 including type, test specification, and test profile, as shown in FIG. 7. If the testing module 210 is unable to identify the foregoing information as shown in FIG. 8 (*i.e.*, the device has not yet been tested), then the testing module 210 can prompt the testing user 151 to enter information to identify the device as shown in FIG. 9. Once the testing module 210 has matched the device 101 to a part number, the testing module 210 can match the device to a test specification and a test profile as shown in FIG. 4 at tables 420 and 430. The test specification can be criteria to which the testing operations will be performed, for example, as specified by the manufacturer or the customer. Test specifications can include, for example, a series of benchmark parameters as shown in FIG. 5 at 506. Test specifications can also include, for example, a schematic associated with the series of parameters as shown in FIG. 5 at 504.

[0057] The test profile as shown in FIG. 4 at table 430 may be a plurality of test sequences that are to be performed upon the well equipment device. A test profile may indicate that certain test sequences shall be run on certain parts, but not on others. For example, test profiles may be defined by "levels" as set forth by the logical process flows shown in FIGS. 6-9.

[0058] Level 1, as set forth in FIG. 6, can include, for example, making an inventory of all iron and entering al serial numbers or parts and specifications into the system. Then a testing user can visually examine and record any defects, damage, worn bodies, threads, and wing nuts on the iron. If the visual examine is acceptable, the tester can proceed with a wall thickness test, as discussed further herein. If the visual examination is unsuccessful, the user can scrap the iron in the database, mark the part with orange paint, and return or destroy the iron so that it becomes

unusable. If the wall thickness is acceptable, the customer can be contacted if the wall thickness is within 5% of the minimum value set forth in the testing specification. If not, the testing user can proceed to the pressure test. If the pressure test is acceptable, the final inspection to be signed off by leading supervisor. If continued testing is desired, the tester can proceed to Level 2 before performing the pressure test.

[0059] Level 2, as set forth in FIG. 7, can include, for example, dismantling and stripping down and discarding all rubber seals and worn or corroded parts, then cleaning and removing grease from affected parts with solvent. Also, the testing user can perform a surface preparation in caustic solution tank, de-scale surfaces area to remove dirt scale, rust, and paint, and pressure rinse to remove caustic solution. The testing user then performs the visual examination as specified for Level 1, and may scrap the part also as specified for Level 1. If proceeding to Level 3 is acceptable, the testing user goes to Level 3 before performing the pressure test. Otherwise, the pressure test can be performed as specified for Level 1.

[0060] Level 3, as set forth in FIG. 8, can include, for example, inspecting the part to make sure its free from all oil, grease, paint, scale, rust, and all contaminates that might degrade the result of this inspection. The testing user then coats area to be inspected with wet fluorescent bath and puts a yoke on the part to create magnetic field. The user can pass the part for the magnetic particle test if, using a black light to check for indications of cracks and rechecking at right angles, the user finds no indications of cracks. If the magnetic particle test fails, the user can scrap the iron in the database as set forth for Level 1. After cleaning the part and completing the inspection buyoff, the testing user can reassemble and fit with news seals and any spare parts required. Thereafter the testing user can perform the pressure test as specified for Level 1 and proceed to paint per the customer's specifications or according to standardized paint schemes as set forth in FIG. 8. After painting, the supervising leader must sign off on the final inspection.

[0061] Test sequences 1300 can include, for example, visual inspection, wall thickness inspection, disassembly/assembly, magnetic ("mag") particle inspection, pressure test, paint, and final inspection. As shown in FIG. 13, test sequences available for the device 101, (*i.e.*, available according to the test profile 430) can be displayed to the testing user 151 using the

testing interface 150 so that the testing user 151 may select one of the available test sequences to be performed.

[0062] Test sequences as shown in FIG. 13 may correspond to one of a plurality of testing apparatus 110. For example, the test sequence "wall thickness inspection" corresponds to the UT meter testing apparatus 110 and the test sequence "pressure test" corresponds to the pressure test pump and transducer. Other test sequences shown in FIG. 13 may correspond to manual procedures; for example, the test sequence "visual inspection" corresponds only to operations to be performed by the testing user 151. Each test sequence, as shown in table 440 of FIG. 4, corresponds to a sequence of testing operations to be performed upon the well equipment device 101.

[0063] Once the testing interface 150 displays the plurality of test sequences 440 available for the well equipment device, the testing user 151 can select a test sequence to be performed. The test sequence should correspond to the testing user positioning the selected well equipment device so that the testing apparatus 110 can perform the testing operations. For example, if the testing user 151 has selected the pressure test sequence, the testing user must also ensure that the appropriate testing apparatus 110 (*e.g.*, the pressure pump and transducer) is positioned upon the selected well equipment device so that the test can be properly performed.

[0064] If the testing user 151 has selected the pressure test sequence or the wall thickness inspection sequence, the testing module 210 will calibrate the testing apparatus 110 as shown in FIG. 14 and FIG. 15. In certain embodiments, the calibration 1400, 1500 can be performed responsive to the tolerances as specified in the test specification 420. Calibration can be performed, for example, by shoring a transducer of the testing apparatus 110 to return a rated pressure value or a baseline calibration setting by the manufacturer, as will be understood by those skilled in the art. Embodiments of the present invention can receive the baseline calibration setting returned and configure a calibration setting responsive thereto.

[0065] According to certain embodiments of the present invention, the testing module 210 systematically controls the performance of testing operations in certain test sequences. For such testing modules having full systematic control of performing the testing operations, *e.g.*, the pressure test sequence, the testing user 151 can initiate the performance of the testing operations

to be controlled by the central management server 100, as shown at control deck 1600 in FIG. 16. The testing module 210 can control the corresponding testing apparatus 110 for the selected testing sequence so that the corresponding testing apparatus 110 performs the sequence of testing operations upon the selected well equipment device 101. For example, the pressure test sequence can be performed responsive to the pressure criteria set forth in the test specification. As shown in FIG. 17, the pressure test proceeds systematically as shown in test chart 1700 and the test module controls the performance of a pressurization of the selected well equipment device 101 for a preselected period of time, for example, as specified in the test specification.

[0066] In further embodiments of the present invention, the testing module 210 systematically controls the performance of some testing operations and requires manual performance of other testing operations ("hybrid systematic/manual"). For testing modules having hybrid systematic/manual performance of testing operations, such as for wall thickness inspection, the testing user 151 can initiate the performance of the testing operations to be controlled by the central management server 100, and the central management server 100 can control the testing apparatus 110 as discussed above with respect to fully systematic testing. Also, the testing module 210 can prompt the testing user 151 with instructions for the testing user 151 to perform testing operations pursuant to the test specification. As shown in FIG. 18 and FIG. 19, the thickness at "Location A" can be measured and input 1800, 1900 either by the UT Meter or by the testing user 151 manually measuring Location A with a digital caliper. The testing module 210 transmits the schematic from the test specification to the testing interface 150 so that it may be displayed 1901 to the testing user 151 and instructs the testing user 151 how to perform the test operations with respect to the information set forth in the schematic and test specification.

[0067] In further embodiments of the present invention, the testing module 210 requires full manual performance of the testing operations for certain test sequences. For testing modules having full manual performance of testing operations, such as for the visual inspection sequence, the testing module 210 can prompt the testing user 151 with instructions for the testing user 151 to perform testing operations pursuant to the test specification. As shown in FIGs. 20-21, band information 2000 and paint parameters 2100 can be input by the testing user 151 responsive to instructions provided by the testing module 210 to the test interface 150, the testing module 210 providing such instructions responsive to the sequence of testing operations and the test

specification. As can be seen in FIG. 17, for example, the testing interface 150 can display the schematic 2001 from the test specification to the testing user 151 and instructs the user how to perform the test operations with respect to information set forth in the schematic and the test specification.

[0068] Responsive to systematic, manual, or hybrid systematic/manual performance of the test operation described above, the testing module 210 receives testing data either as captured by the testing apparatus 110 for the corresponding testing sequence or as captured by the testing user 151 and entered into the testing interface 150 according to specific instructions provided by the testing module 210, e.g., at banding menu 2000. As shown in FIG. 4, the testing data is stored in the table 440 and linked to the device library 400 for the selected well equipment device 101. Also as shown in FIG. 4, an exemplary embodiment of the testing data in table 440 can have individual cells for each testing sequence (*e.g.*, wall thickness, pressure test, visual inspection, etc.). The testing data in table 440 can be used, as is discussed further herein, to generate certification data by execution of the certification module 220 on the processor 251.

[0069] Additionally, further embodiments of the present invention include certain test sequences as described in FIGS. 6-9. These test sequences, for example, can include disassembly/assembly, magnetic particle ("mag particle") inspection, paint, and final inspection. Although an embodiment of the invention includes manual performance of the test operations for these sequences, each of these test sequences may be implemented either by systematic, manual, or hybrid systematic/manual performance of the testing operations. Regardless of whether the performance of the testing operations are performed systematically or manually, those skilled in the art will realize that all testing operations are performed responsive to a command or instruction being systematically issued by the testing module 210 when executed on the central management server 100. As such, any test operation described herein as manual can be performed systematically provided there exists a testing apparatus 110 that can receive an instruction from the central management server 100 to perform the operation. For example, the performance of test operations using a digital caliper may be performed either manually or systematically, although an embodiment employs manual performance of such operations. Those skilled in the art will understand that it is within the scope of the invention to employ a testing apparatus 110 having a digital caliper, actuator, and an control device to systematically

perform a wall thickness measurement using a digital caliper in addition to the embodiment employing manual performance. Likewise, it will be understood by those in the art that any manual operation described herein may also be performed systematically under the architecture of the central management server as set forth in FIG. 2.

Certification Module 220

[0070] As is shown in FIG. 2, the certification module 220 may be a computer program product stored in the non-transitory memory 240 on the central management server 100 and operable on the processor 251 thereof. Computer program product 220 contains instructions that are operable on the processor 251 that cause the certification module 220 and the central management server 100 to perform the operations discussed further herein.

[0071] The certification module 220 can interact with the processor to receive or transmit data, instructions, and other information from or to any of the devices connected to I/O 252. In addition both the certification module 220 and the testing module 210 are in communication with the processor 251 and the non-transitory memory 240 so that modules can pass or return variables between modules according to a shared API or access global variables being stored on the non-transitory memory 240 to ensure interoperability and open communication between computer program products in communication with the processor 251. Likewise, those skilled in the art will understand that computer program products 220 and 210 are capable of passing, returning, or referencing common variables regardless of whether computer program products are executed on the same processor 251, but that a common API will allow interoperability and open communications. In embodiments discussed below, the certification module 220 at least interacts with the testing interface 150, RFID reader 130, RFID writer 140, and database 170. Although testing interface 150 has been described to be a PC, testing interface 150 can also be implemented in whole or in part as a user terminal interface on the central management server 100 itself, using a keyboard, display, or media inputs and outputs connecting to the I/O 252. The testing interface 150 can also be a lightweight graphical user interface (GUI) operable over a web browser and viewable on any browser-enabled device, such as a PC, smart phone, or other equipment having a processor and computer functionality.

[0072] The certification module 220 can receive a device identifier for a selected well equipment device 101. As described above, "well equipment devices" includes the equipment and devices used in hydraulic fracturing for oil and gas wells, i.e. "high pressure hydraulic fracturing flow iron," "frac iron," or, simply, "iron." Frac iron can include, for example, a slurry blender, high pressure/volume fracturing pumps, high pressure treating iron, and other pipes, joints, valves, and fittings. For example, frac iron can include swivel joints, pup joints, plug valves, check valves and relief valves. Furthermore, by way of example, frac iron can include any type of ball injector, crow's foot, air chamber, crossover, hose, pipes/piping, hose loop, ball injector tee body, tee, wye, lateral, ell, check valve, plug valve, wellhead adapter, swivel joint, plug, relief valve, densometer, cross, frac pump, or cement pump. The selected well equipment device is a well equipment device that has previously undergone testing, for example, as described above with respect to the testing module 210. The certification module 220 can receive a device identifier, for example, responsive to receiving input from the testing interface 150 as entered therein by a testing user 151. The certification module 220 can also receive a device identifier, for example, responsive to receiving input from a remote user interface as entered therein by a remote user 161. Furthermore, the certification module 220 can receive a device identifier from the testing module 210 responsive to the testing module 210 having completed execution of the testing operations and the generation and linking of the testing data in the database 170. The certification module 220 can identify a selected well equipment device responsive to the device identifier and generate and link certification data in database 170, for example, in certification table 450, responsive to the testing data. For example, the certification data 450 can include all data as can be entered onto certificate 500 as a summary or other rendering of testing data responsive to testing operations being performed on the well equipment device 101, for example, a graphical representation of a pressure test 503. The certification module 220 can include logic to generate charts and data modeling based upon testing data, which is raw data stored, for example, in table 440. Further examples of summaries or renderings of raw testing data responsive to the testing operations appear on the face of certificate 500. As a result of the linking operation, the certification data 440 can be readily accessed or queried according to a serial number for a well equipment device.

[0073] The certification module 220 can also generate certification data in a format responsive the proprietary data table format for the exemplary RFID certificate. For example,

certification module 220 may generate certificate data according to specific standards or protocols employed in the proprietary standard, for example, cell size, packet size, header length, payload length, etc. The RFID certificate can be generated so that it is ready to be stored to the media attached to the well equipment without further processing. The certification module 220 may also include logic for rendering graphics stored as certification data, such as the schematics and charts, into a lightweight graphics formats such as vector graphics formats. The RFID certificate, for example, can include all fields available on the paper document, including device identifier 501, pass or fail grading 502, tabular summary or rendering of test data 503, drawing 504, measured values 505, and demanded values 506. The tabular summary or rendering 503 and the drawing 504 can be encoded in lightweight vector graphics formats, for example.

Reporting Module 230 and Enterprise Resource Planning Interface

[0074] As is shown in FIG. 2, the reporting module 230 may be a computer program product stored in the non-transitory memory 240 on the central management server 100 and operable on the processor 251 thereof. Computer program product 230 contains instructions that are operable on the processor 251 that cause reporting module 230 and the central management server 100 to perform the operations discussed further herein.

[0075] The reporting module 230 can interact with the processor 251 to receive or transmit data, instructions, and other information from or to any of the devices connected to I/O 252. In addition, both the reporting module 230 and the testing module 210 are in communication with the processor 251 and non-transitory memory 240 so that these two modules can pass or return variables between each other according to a common application programming interface (API) or shared global variables being stored on the non-transitory memory 240, thereby enhancing interoperability and open communication between the modules. Likewise, those skilled in the art will understand that computer program products 230 and 220 are capable of passing, returning, or referencing common variables regardless of whether computer program products are executed on the same processor 251 and that a common API will allow interoperability and open communications as described above. In embodiments discussed below, the reporting module 230 at least interacts with the testing module 210, certification module 220, and database 170. Although remote user interface 160 may be a PC as has been described for testing interface 150,

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remote user interface 160 can also be implemented in whole or in part as a user terminal interface on the central management server 100 itself, using a keyboard, display, or media inputs and outputs connecting to the I/O 252. Remote user interface 160 can also be a lightweight graphical user interface (GUI) operable over a web browser and viewable on any browser-enabled device, such as a PC, smart phone, or other equipment having a processor and computer functionality.

[0076] The reporting module 230 can receive a device identifier for a selected well equipment device 101, the selected well equipment device being a well equipment device that has previously undergone testing, for example, as described above with respect to the testing module 210. The reporting module 230 can receive a device identifier, for example, responsive to receiving input from the testing interface 150 as entered therein by a testing user 151. The reporting module 230 can also receive a device identifier from any other module, as discussed above. In response to receiving the device identifier, the reporting module 230 can match the device identifier to any desired data in the database 170, for example, testing data in the database at testing data table 440, certification data in the certification data table 450, device library data from the device library table 410, and test specification data from the specification library 420. The reporting module, responsive to the device identifier, can return any of the test specification for the selected well equipment device 101, testing data for a plurality of testing sequences performed on the selected well equipment device 101, and certificate data for the selected well equipment device 101, for example, according to the database structure provided in FIG. 4.

[0077] The reporting module 230 may also receive an indication or selection of additional variables for reporting purposes, for example, a part number, work order number, etc. In the event that the reporting module 230 receives an additional variable, the reporting module 230 can or expand or refine the matched data with respect to the additional variable. For example, the reporting module 230 may receive a device identifier, a work order number, and the reporting module 230 will return a list of all certifications, tests, or specifications for that device identifier according to the tests performed under the received work order number. On the other hand, a reporting module 230 may receive a device identifier and a part number, and the reporting module 213 will return a list of all certifications, tests, or specifications for either the selected well device 101 or all well devices tested having the selected the part number.

[0078] Embodiments of the present invention employing the reporting module 230 are beneficial in that they transform the task of testing and certification—once a costly operational hurdle—into a robust data-point in business and operational management decisions. For example, manufacturers may use embodiments of the reporting module in research and development to better understand wear patterns and rates in real-world applications, to build a better product, and to manage customer relations. As those skilled in the art will appreciate, the reporting module 230 can be a powerful tool in achieving management-level value from systematic testing and certifications, which provides a comprehensive and reliable (*i.e.*, consistent) pool of data pertaining to asset management, inventory management, purchasing, risk management, and other business analytics. Exemplary reports generated by the reporting module 13 are shown in FIGS. 24-25.

[0079] Furthermore, embodiments of the present invention can employ an ERP (Enterprise Resource Planning) interface (not pictured) connected to the I/O of the central management server 100 to provide the foregoing benefits realized by the reporting module, but in a manner that is more fully integrated into enterprise-wide information systems and providing high levels of cross-functional integration, network scalability, and real-time data synchronization. In particular, embodiments of the present invention employ an ERP interface for the purposes of invoicing the testing and certification operations, for example, responsive to work order information entered by a testing user 151 to the testing interface 150 as shown in FIG. 6.

RFID 130, 135, 140

[0080] Furthermore, embodiments of the present invention can achieve some or all of the foregoing objectives by providing a central management server 200 that can communicate with one or more well equipment devices 101. For example, the central management server 200 can be in communication with the one or more well equipment devices using wireless communication technologies, for example, radio frequency identification (RFID) technologies. The one or more well equipment devices 101 can include an RFID tag 135, and the central management server 200 can communicate with the RFID tag 135 on the one or more well equipment devices using an RFID reader 130 in communication with the central management server 200 through the I/O 252. In an embodiment, the RFID tag is a UHF Gen-2 RFID tag that

is attached to the frac iron using a clamp designed to be sufficiently robust so that the RFID tag is not affected by the harsh operating conditions of the downhole environment.

[0081] In an embodiment, the RFID reader 130 and RFID 140 are peripherals to the testing interface 150, attaching thereto by known connection means in the art, such as a USB cable or cables. In certain embodiments, the RFID reader and RFID writer may be one unit, such as an RFID reader/writer device.

[0082] The RFID reader 130 can read a device identifier from the RFID tag on a selected well equipment device 101 through radio frequency communication and transmit the device identifier to the central management server 200. The central management server is positioned to receive the device identifier from the RFID reader 130. Any of the computer program products discussed herein, such as the testing module 210, can receive a device identifier responsive to the central management server 200 receiving a device identifier from the RFID reader 130. An embodiment of a computer-implemented method for using the RFID reader 130 includes the testing user 151 having a handheld and/or remote RFID reader 130 in physical proximity to the selected well equipment device 101 and the RFID tag 135 thereon so that the testing user can interrogate the RFID tag 135 and so that the RFID tag can transmit the device identifier to the RFID reader 130.

[0083] The RFID writer 140 can write an RFID certificate to the RFID tag on a selected well equipment device 101 through radio frequency communication and transmit the device identifier to the central management server 200. The RFID certificate can have the qualities and properties as described herein, preferably including at least a serial number. The central management server is positioned to transmit the RFID certificate or any data included therein to the RFID writer 140 responsive to any of the computer program products discussed herein, such as the certification module 220. An embodiment of a computer-implemented method for using the RFID writer 140 includes the testing user 151 having a handheld or remote RFID writer 140 in physical proximity to the selected well equipment device 101 and the RFID tag 135 thereon so that the testing user can establish a communication link with the RFID tag 135 and so that the RFID writer can transmit and store the RFID certificate or the information therein to the RFID tag 135.

[0084] This application claims priority and is related to U.S. Provisional Patent Application No. 61/330,248 filed April 30, 2010 titled "Machines, Systems, Computer-Implemented Methods, And Computer Program Products To Test And Certify Oil And Gas Equipment," which is incorporated by reference in its entirety herein.

[0085] The foregoing has broadly outlined certain features, and technical advantages of the present invention and a detailed description of the invention so that embodiments of the invention may be better understood in light of features and advantages of the invention as described herein, which form the subject of certain claims of the invention. It should be appreciated that the conception and specific embodiments disclosed may be readily utilized as a basis for modifying or designing other structures for carrying out the same purposes of the present invention. It should also be realized that such equivalent constructions do not depart from the invention as set forth in the appended claims. The novel features which are believed to be characteristic of the invention, both as to its organization and method of operation, together with further advantages are better understood from the description when considered in connection with the accompanying figures. It is to be expressly understood, however, that such description and figures are provided for the purpose of illustration and description only and are not intended as a definition of the limits of the present invention. For example, although the example embodiments discussed herein are directed to oil and gas hydraulic fracturing operations, it should be specifically noted that the systems, machines, methods, and computer program products to test and certify well equipment devices may be employed to carry out similar functions for other equipment or devices requiring routine testing and certification, including without limitation, aircraft maintenance and construction, ship maintenance and construction, facilities maintenance and construction, and so on.

That Claimed Is:

1. A machine to manage periodic testing and certification of well equipment devices, the testing and certification being facilitated by a plurality of testing apparatus performing one or more testing operations upon the well equipment devices, the machine comprising:

a processor;

a non-transitory memory;

an input/output unit to communicate with the plurality of testing apparatus;

a database positioned to match a device identifier to a well equipment device, a test specification, and a plurality of testing sequences;

a testing module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the testing module being operable by the processor, the testing module comprising a set of instructions that, when executed by the processor, cause the testing module to perform the following operations:

identifying a selected well equipment device, a device test specification, and a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations,

selecting a testing sequence of the plurality of testing sequences, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device,

controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing

operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification,

generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations, and

linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in the database so that a certificate can be generated responsive thereto; and

a certification module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the certification module being operable by the processor, the certification module comprising a set of instructions that, when executed by the processor, cause the certification module to perform the following operations:

identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device,

generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been performed upon the selected well equipment device responsive to the device test specification, and

linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in the database so that the certificate can be readily recalled from the database responsive to the device identifier.

2. A machine as defined in Claim 1, wherein the input/output unit is further positioned to communicate with a testing interface, the testing module further performing the following operation:

calibrating the corresponding testing apparatus for the selected testing sequence responsive to the device test specification responsive to receiving a selection of a test sequence from the testing interface.

3. A machine as defined in Claim 2, the testing module further performing the following operations:

delivering to the testing interface the device test specification and instructions for performing the sequence of testing operations so that a local user may view the device test specification on a graphical display of the testing interface and so that the local user may perform the sequence of testing operations upon the selected well equipment device responsive to the device test specification;

generating testing data for the selected testing sequence responsive to receiving user data from the testing interface, the user data having been input to the testing interface responsive to the user performing the sequence of testing operations upon the selected well equipment device.

4. A machine as defined in Claim 1, wherein the input/output unit is further positioned to communicate with a remote user interface, the machine further comprising:

a reporting module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the reporting module being operable by the processor, the reporting module comprising a set of instructions that, when executed by the processor, cause the reporting module to perform the following operations:

identifying a selected well equipment device, a device test specification, testing data for a plurality of testing sequences, and a certificate, the identifying operation responsive to receiving a device identifier for the selected well equipment device from the remote user interface,

delivering to the remote user interface at least one of the testing data, the device test specification, and the certificate responsive to the identifying operation.

5. A machine as defined in Claim 1, wherein:

the input/output unit is further positioned to communicate with an RFID reader; and

the receiving a device identifier for the selected well equipment device is responsive to interrogating a device RFID tag using the RFID reader, the device RFID tag being attached to the selected well equipment device and having the device identifier encoded thereon.

6. A machine as defined in Claim 5, wherein the input/output unit is further positioned to communicate with an RFID writer, the certification module further performing the following operations:

generating an RFID certificate responsive to the certificate, the RFID certificate being formatted so that the RFID certificate is recognizable by a remote interrogation device having an RFID reader; and

delivering an RFID certificate to the device RFID tag using the RFID writer so that the RFID certificate can be readily accessed by the remote interrogation device.

7. A system to certify oil and gas well equipment, the system comprising:

a plurality of devices to be used in well equipment to define a plurality of well equipment devices, each well equipment device of the plurality of well equipment devices having a device identifier associated therewith;

a central management server positioned to identify a device test specification and a plurality of testing sequences for a selected well equipment device responsive to receiving a device identifier for the selected well equipment device, the device test specification and the plurality of testing sequences defining certification criteria for the well equipment device;

a plurality of testing apparatus, each testing apparatus positioned to perform a testing sequence upon the well equipment device, the testing sequence being a sequence of testing operations, the sequence of testing operations being performed responsive to the device test specification;

a plurality of controllers, each controller positioned to receive commands responsive to the certification criteria from the central management server and to control the plurality of testing apparatus performing the sequence of testing operations upon the selected well equipment device responsive to the device test specification; and

a certificate generated responsive to the plurality of testing apparatus performing the plurality of testing sequences upon the well equipment device, the certificate indicating whether selected well equipment device has been tested according to the certification criteria within a pre-selected period of time.

8. A system as defined in Claim 7, the system further comprising:

a plurality of device RFID tags, each device RFID tag of the plurality of device RFID tags being attached to a well equipment device of the plurality of well equipment devices and having a device identifier for the well equipment device encoded thereon; and

an RFID reader in communication with the central management server and the plurality of device RFID tags, wherein the central management server is positioned to receive the device identifier for a well equipment device having a device RFID tag attached thereto responsive to the RFID reader interrogating the device RFID tag.

9. A system as defined in Claim 8, the system further comprising an RFID writer in communication with the central management server and the plurality of device RFID tags, wherein the central management server is positioned to generate an RFID certificate responsive to the certificate and deliver the RFID certificate to a device RFID tag using the RFID writer.

10. A system as defined in Claim 7, the system further comprising database positioned to match a device identifier to a well equipment device, a device test specification, and a plurality of testing sequences, wherein the central management server identifies a device test specification and a plurality of testing sequences for a selected well equipment device responsive to matching the device identifier in the database.

11. A system as defined in Claim 7, the system further comprising a testing interface in communication with the central management server, wherein:

each testing apparatus of the plurality of testing apparatus is positioned to perform a testing sequence responsive to receiving a selection of the testing sequence from the testing interface; and

the certificate is also generated responsive to user data received from the testing interface, the user data having been input to the testing interface responsive to the user performing the sequence of testing operations upon the selected well equipment device responsive to the device test specification.

12. A computer-implemented method to manage periodic testing of a plurality of well equipment devices, the testing being facilitated by a plurality of testing apparatus performing one or more testing operations upon the plurality of well equipment devices, the computer-implemented method comprising the following operations:

receiving a device identifier for a selected well equipment device of the plurality of well equipment devices;

identifying the selected well equipment device, a device test specification, and plurality of testing sequences, the identifying operation being responsive to the receiving operation, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations;

selecting a testing sequence of the plurality of testing sequences to define a selected testing sequence, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device;

calibrating the corresponding testing apparatus for the selected testing sequence responsive to the device test specification;

controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the

selected well equipment device, the sequence of testing operations being performed responsive to the device test specification;

generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations; and

linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in a database so that a certificate can be generated responsive thereto.

13. A computer-implemented method as defined in Claim 12 wherein the selecting operation is responsive to receiving a selection of the test sequence from a testing interface.

14. A computer-implemented method as defined in Claim 12, further performing the following operation:

calibrating the corresponding testing apparatus for the selected testing sequence responsive to the device test specification responsive to receiving a selection of a test sequence from the testing interface.

15. The computer-implemented method as defined in Claim 13, the computer-implemented method further comprising the following operations:

delivering to the testing interface the device test specification and instructions for performing the sequence of testing operations so that a local user may view the device test specification on a graphical display of the testing interface and so that the local user may perform the sequence of testing operations upon the selected well equipment device responsive to the device test specification;

generating testing data for the selected testing sequence responsive to receiving user data from the testing interface, the user data having been input to the testing interface responsive to the user performing the sequence of testing operations upon the selected well equipment device.

16. A computer-implemented method as defined in Claim 12 wherein receiving a device identifier for the selected well equipment device is responsive to interrogating a device RFID tag using a RFID reader, the device RFID tag being attached to the selected well equipment device and having the device identifier encoded thereon.

17. A computer-implemented method to manage periodic certification of a plurality of well equipment devices, the certification based upon testing data generated responsive to a plurality of testing apparatus performing one or more testing operations upon the plurality of well equipment devices, the computer-implemented method comprising the following operations:

identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device;

generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been performed upon the selected well equipment device responsive to the device test specification; and

linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in a database so that the certificate can be readily recalled from the database responsive to the device identifier.

18. A computer-implemented method as defined in Claim 16, the computer-implemented method further comprising the following operations:

delivering an RFID certificate to a device RFID tag using an RFID writer so that the RFID certificate can be readily accessed by the remote interrogation device, the device RFID tag being attached to the selected well equipment device and having the device identifier encoded thereon.

19. A computer program product stored in a memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the computer program product being

operable by a processor, the computer program product comprising a set of instructions that, when executed by the processor, cause the testing module to perform the following operations:

identifying a selected well equipment device, a device test specification, and a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations;

selecting a testing sequence of the plurality of testing sequences, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device;

controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification;

generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations;

linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in the database so that a certificate can be generated responsive thereto;

identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device;

generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been

performed upon the selected well equipment device responsive to the device test specification; and

linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in the database so that the certificate can be readily recalled from the database responsive to the device identifier.

FIG. 1

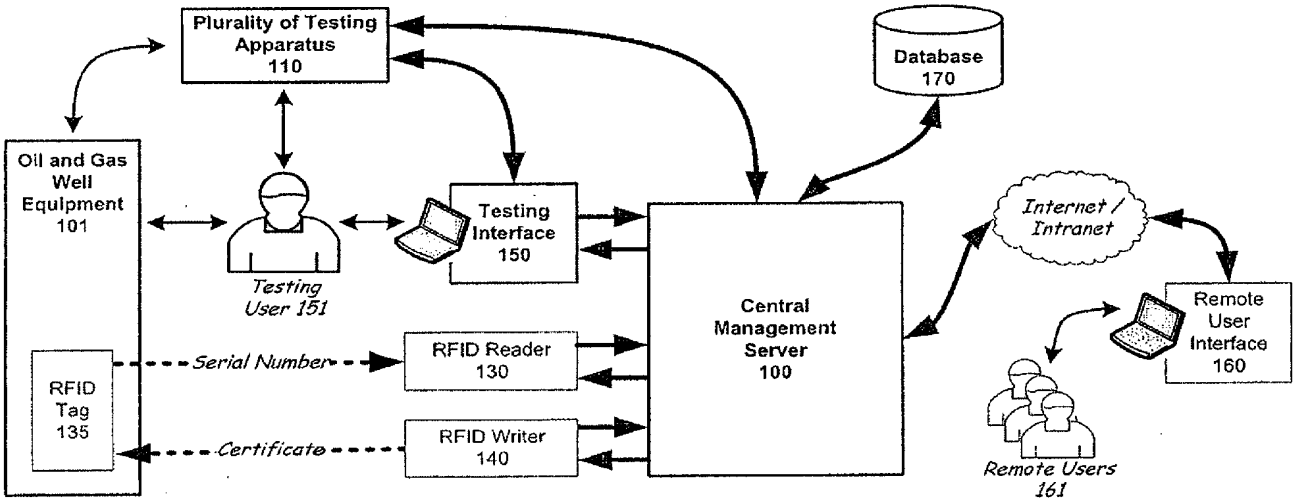

Plurality of Testing Apparatus 110
Database 170
Oil and Gas Well Equipment 101
Testing Interface 150
Testing User 151
Central Management Server 100
Internet / Intranet
Remote User Interface 160
RFID Tag 135
Serial Number
RFID Reader 130
Certificate
RFID Writer 140
Remote Users 161

FIG. 2

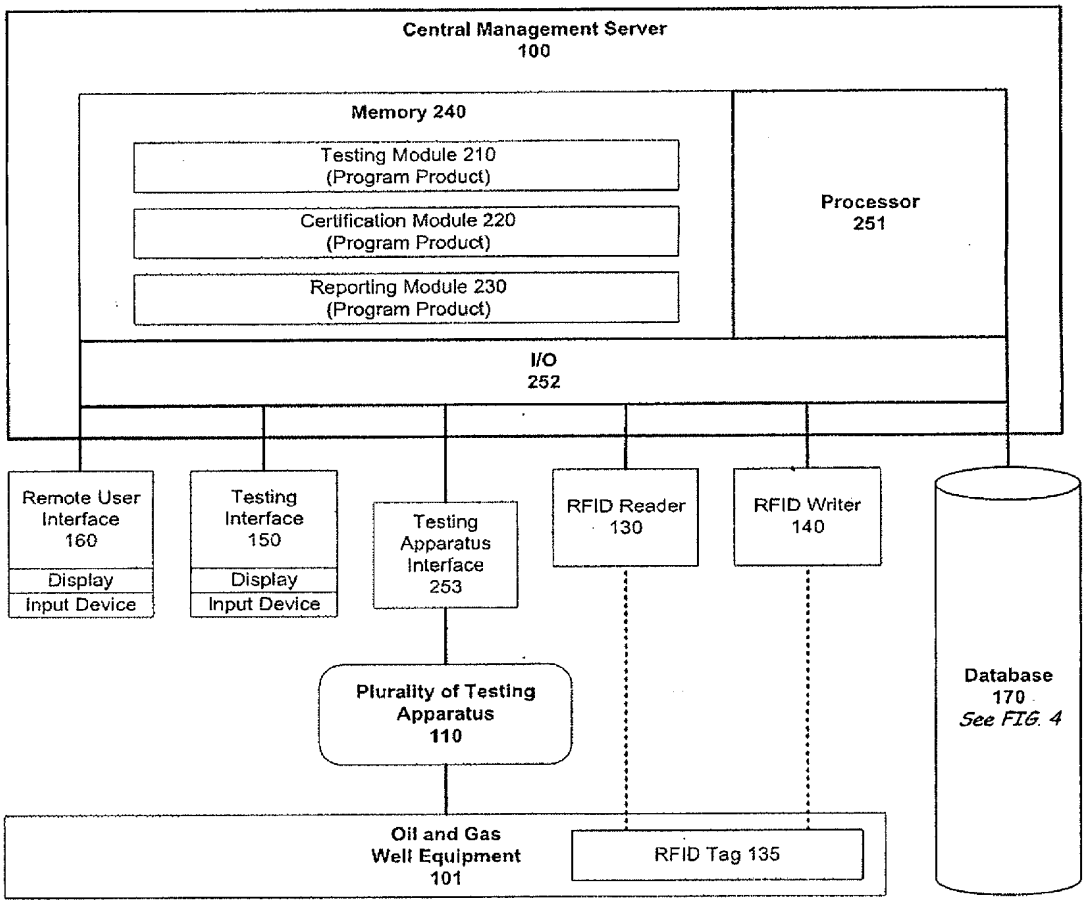

Central Management Server 100
Memory 240
Testing Module 210 (Program Product)
Certification Module 220 (Program Product)
Reporting Module 230 (Program Product)
Processor 251
I/O 252
Remote User Interface 160
Display
Input Device
Testing Interface 150
Display
Input Device
Testing Apparatus Interface 253
RFID Reader 130
RFID Writer 140
Database 170 See FIG. 4
Plurality of Testing Apparatus 110
Oil and Gas Well Equipment 101
RFID Tag 135

FIG. 3

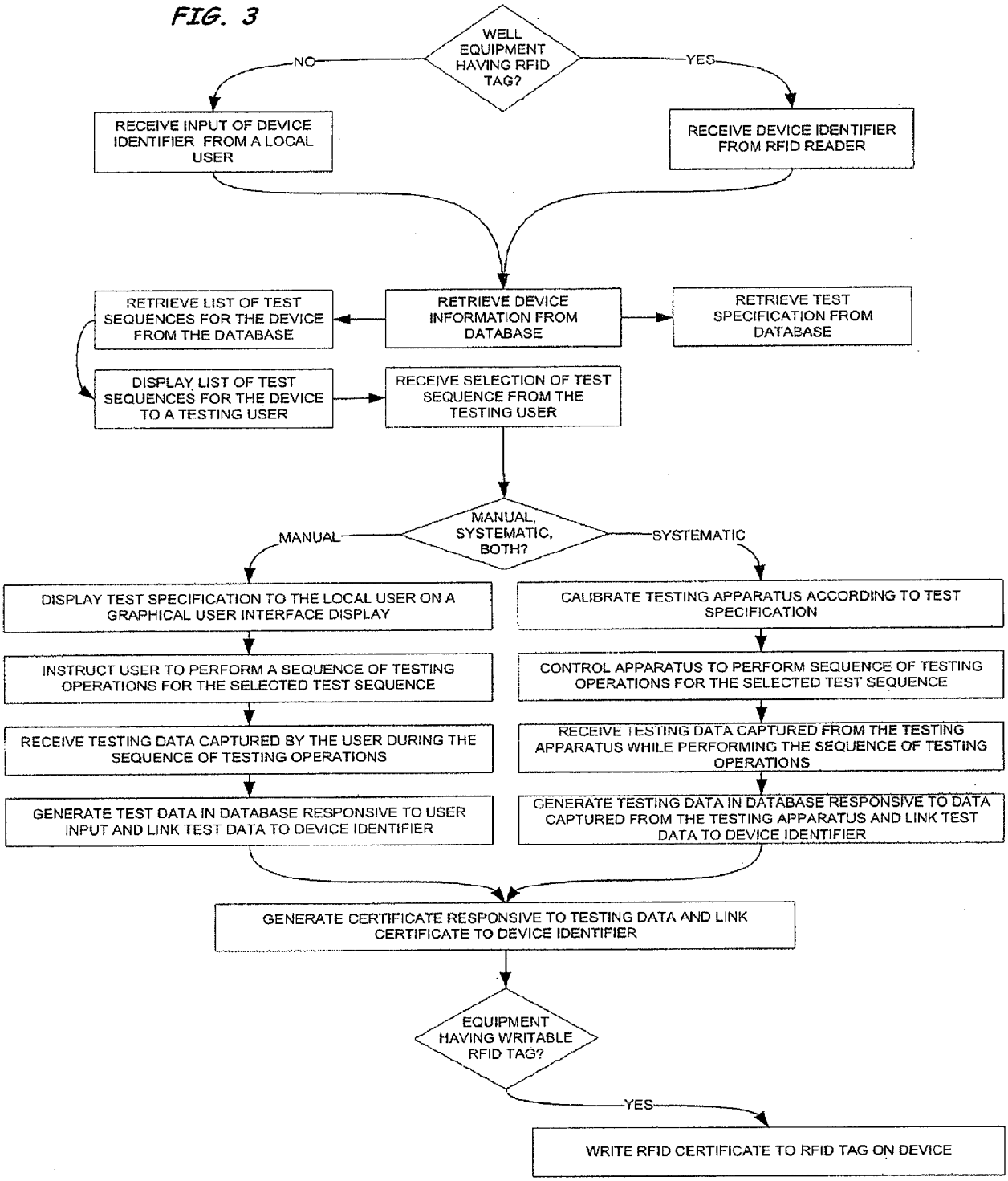
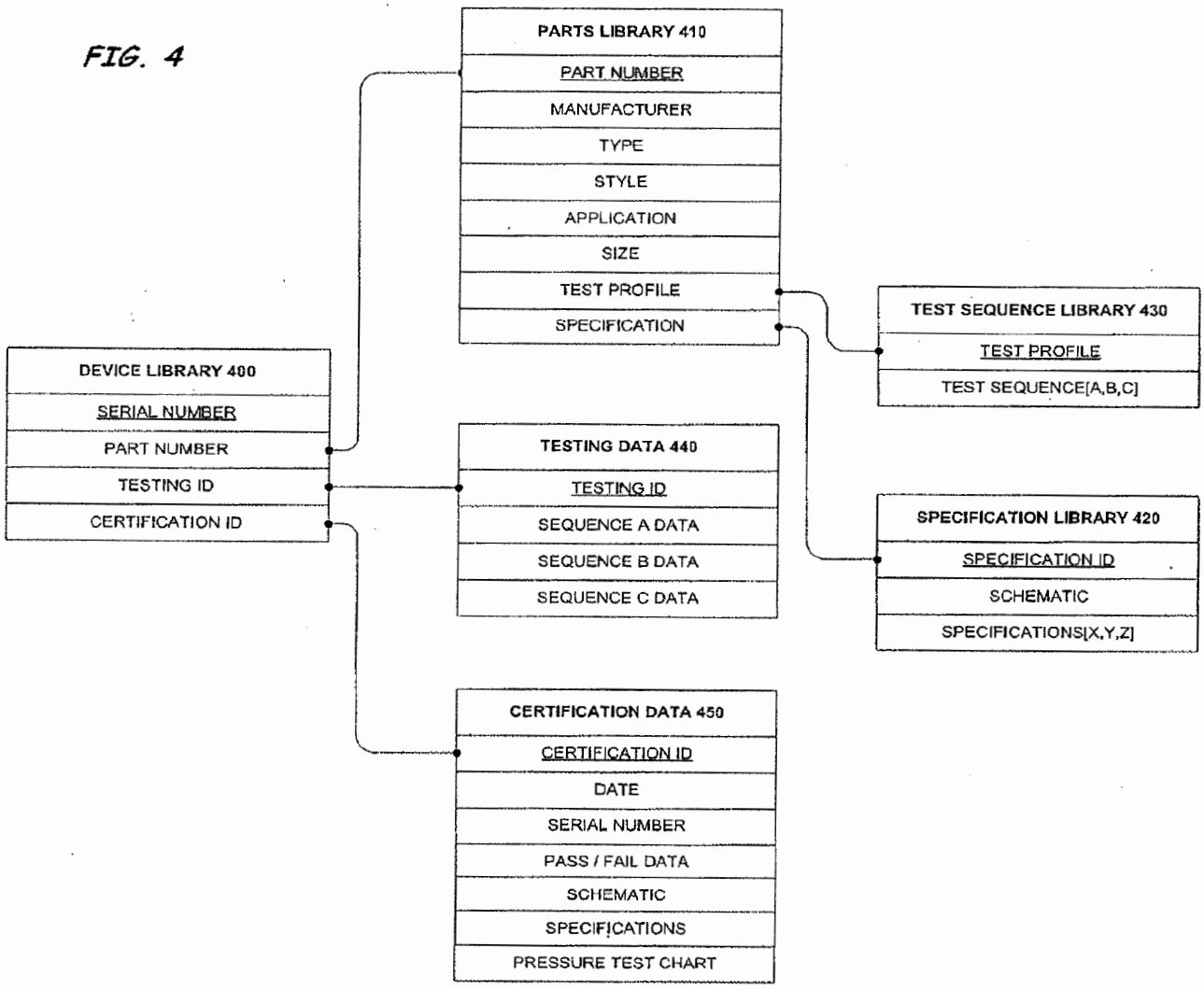

WELL EQUIPMENT HAVING RFID TAG?
NO
YES
RECEIVE INPUT OF DEVICE IDENTIFIER FROM A LOCAL USER
RECEIVE DEVICE IDENTIFIER FROM RFID READER
RETRIEVE LIST OF TEST SEQUENCES FOR THE DEVICE FROM THE DATABASE
RETRIEVE DEVICE INFORMATION FROM DATABASE
RETRIEVE TEST SPECIFICATION FROM DATABASE
DISPLAY LIST OF TEST SEQUENCES FOR THE DEVICE TO A TESTING USER
RECEIVE SELECTION OF TEST SEQUENCE FROM THE TESTING USER
MANUAL, SYSTEMATIC, BOTH?
MANUAL
SYSTEMATIC
DISPLAY TEST SPECIFICATION TO THE LOCAL USER ON A GRAPHICAL USER INTERFACE DISPLAY
INSTRUCT USER TO PERFORM A SEQUENCE OF TESTING OPERATIONS FOR THE SELECTED TEST SEQUENCE
RECEIVE TESTING DATA CAPTURED BY THE USER DURING THE SEQUENCE OF TESTING OPERATIONS
GENERATE TEST DATA IN DATABASE RESPONSIVE TO USER INPUT AND LINK TEST DATA TO DEVICE IDENTIFIER
CALIBRATE TESTING APPARATUS ACCORDING TO TEST SPECIFICATION
CONTROL APPARATUS TO PERFORM SEQUENCE OF TESTING OPERATIONS FOR THE SELECTED TEST SEQUENCE
RECEIVE TESTING DATA CAPTURED FROM THE TESTING APPARATUS WHILE PERFORMING THE SEQUENCE OF TESTING OPERATIONS
GENERATE TESTING DATA IN DATABASE RESPONSIVE TO DATA CAPTURED FROM THE TESTING APPARATUS AND LINK TEST DATA TO DEVICE IDENTIFIER
GENERATE CERTIFICATE RESPONSIVE TO TESTING DATA AND LINK CERTIFICATE TO DEVICE IDENTIFIER
EQUIPMENT HAVING WRITABLE RFID TAG?
YES
WRITE RFID CERTIFICATE TO RFID TAG ON DEVICE

FIG. 4


PARTS LIBRARY 410
PART NUMBER
MANUFACTURER
TYPE
STYLE
APPLICATION
SIZE
TEST PROFILE
SPECIFICATION
TEST SEQUENCE LIBRARY 430
TEST PROFILE
TEST SEQUENCE[A,B,C]
DEVICE LIBRARY 400
SERIAL NUMBER
PART NUMBER
TESTING ID
CERTIFICATION ID
TESTING DATA 440
TESTING ID
SEQUENCE A DATA
SEQUENCE B DATA
SEQUENCE C DATA
SPECIFICATION LIBRARY 420
SPECIFICATION ID
SCHEMATIC
SPECIFICATIONS[X,Y,Z]
CERTIFICATION DATA 450
CERTIFICATION ID
DATE
SERIAL NUMBER
PASS / FAIL DATA
SCHEMATIC
SPECIFICATIONS
PRESSURE TEST CHART

500

501

CERTIFICATION

SERIAL NUMBER:

Customer:	**Cust Num:**	**Plant:**
Work Order:	**Part Num:** 2A1	**Mfr:**
Description:	MXF/INT/4 LR10 WR	
District		

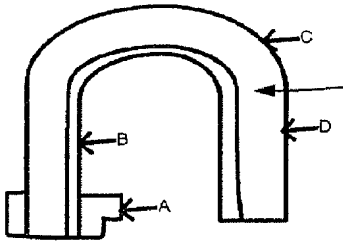
Visual Inspection - PASS 502

Comments:
Inspected By: SCOTT H **Test Date:** March 18, 2010

Wall Thickness Inspection - PASS 502 504

Comments:
Thickness Gauge: VERSION: 1.13 /1.01s
Gauge Cal Date: March 18, 2010
Wall Thickness Values (minimum in parenthesis):
A: 0.60"(0.40"), B: 0.60"(0.44"), C: 0.88"(0.36"), D: 0.89"(0.39"),

505 506



Inspected By:
Test Date:

Disassembly/Assembly - PASS 502

Comments:
Inspected By: **Test Date:** March 18, 2010

Magnetic Particle Inspection - N/A 502

Comments: THIS TEST WAS NOT PERFORMED FOR THIS IRON.
Mag Part **Gauge Cal Date:**
Inspected By: **Test Date:**

Pressure Test - PASS 502 503

Comments: good
Required Test Pres: 10000 PSI
Rated Working Pres: 10000 PSI
Test Duration: minutes
Tested By:
Approved By:
Test Date: March 18, 2010
Pres Gauge: 357808
Gauge Cal Date: March 16, 2010
Pres Recorder:
Recorder Cal Date:

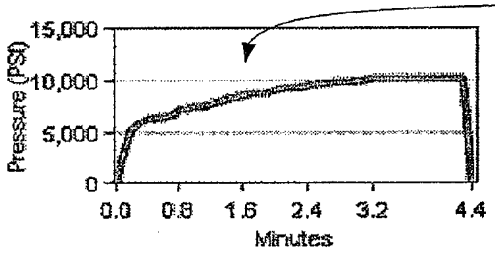


FIG. 5

FIG. 6

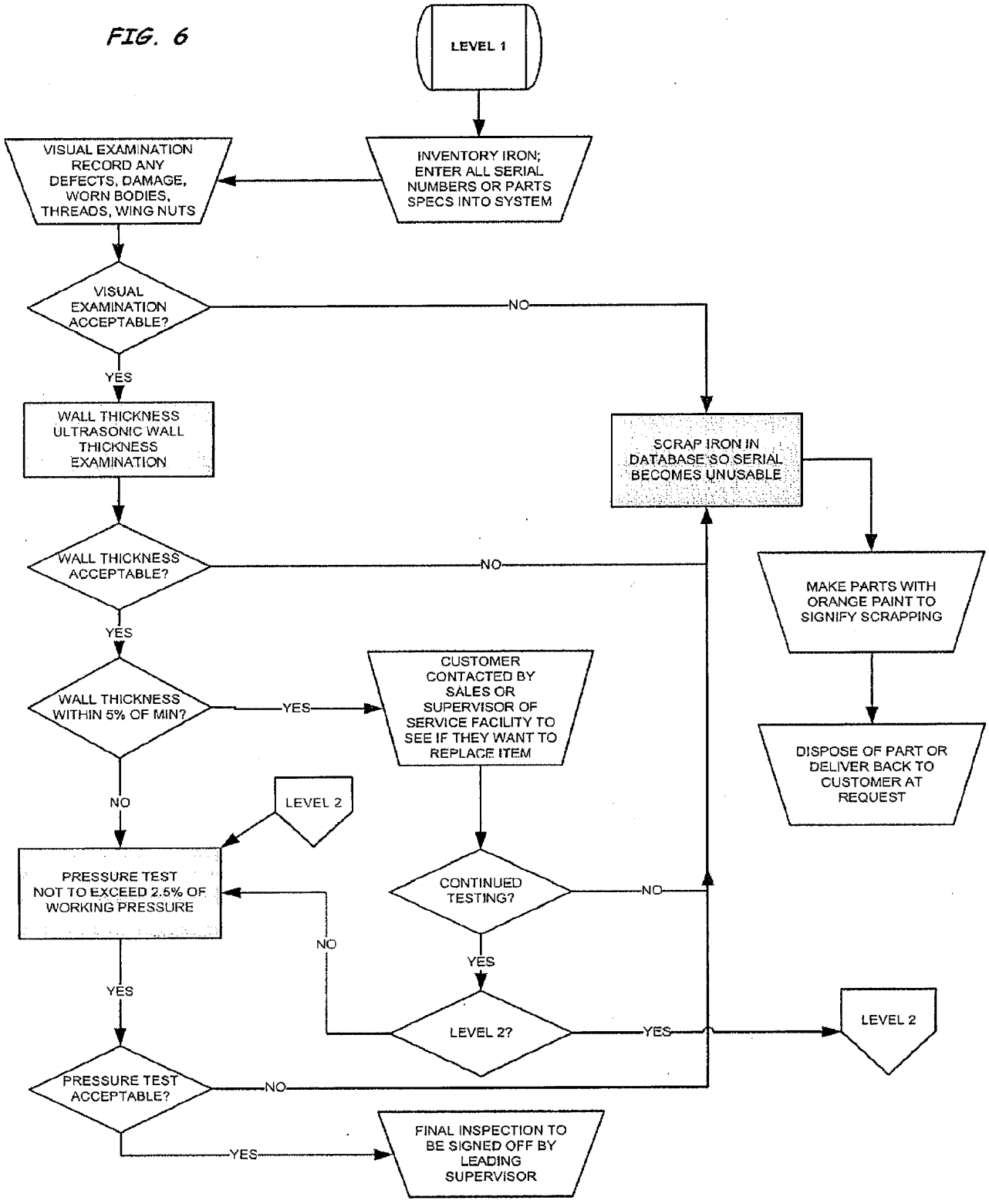
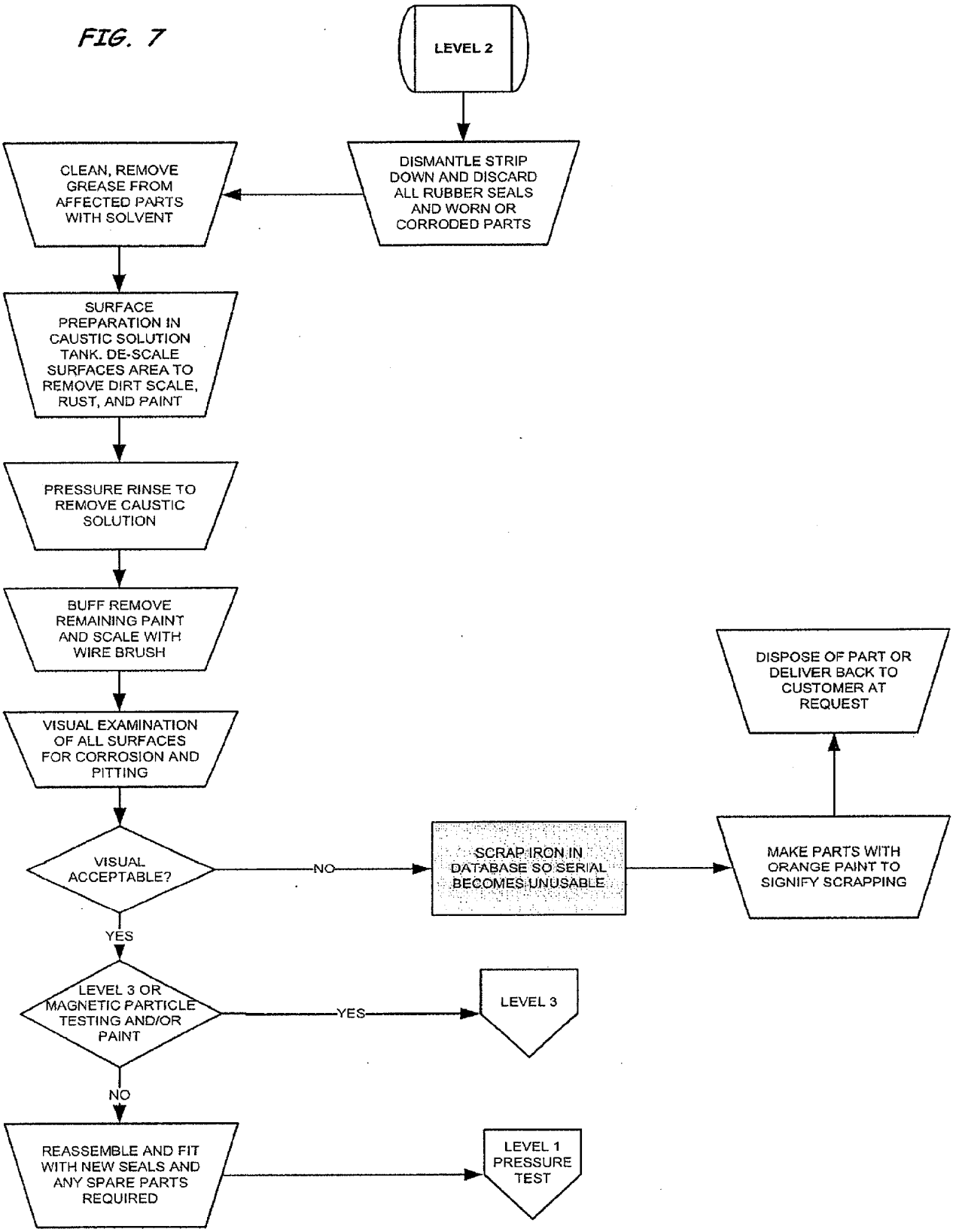

LEVEL 1
INVENTORY IRON; ENTER ALL SERIAL NUMBERS OR PARTS SPECS INTO SYSTEM
VISUAL EXAMINATION RECORD ANY DEFECTS, DAMAGE, WORN BODIES, THREADS, WING NUTS
VISUAL EXAMINATION ACCEPTABLE?
NO
YES
WALL THICKNESS ULTRASONIC WALL THICKNESS EXAMINATION
SCRAP IRON IN DATABASE SO SERIAL BECOMES UNUSABLE
WALL THICKNESS ACCEPTABLE?
NO
YES
MAKE PARTS WITH ORANGE PAINT TO SIGNIFY SCRAPPING
WALL THICKNESS WITHIN 5% OF MIN?
YES
CUSTOMER CONTACTED BY SALES OR SUPERVISOR OF SERVICE FACILITY TO SEE IF THEY WANT TO REPLACE ITEM
DISPOSE OF PART OR DELIVER BACK TO CUSTOMER AT REQUEST
NO
LEVEL 2
PRESSURE TEST NOT TO EXCEED 2.5% OF WORKING PRESSURE
CONTINUED TESTING?
NO
YES
NO
YES
LEVEL 2?
YES
LEVEL 2
PRESSURE TEST ACCEPTABLE?
NO
YES
FINAL INSPECTION TO BE SIGNED OFF BY LEADING SUPERVISOR

FIG. 7


LEVEL 2
DISMANTLE STRIP DOWN AND DISCARD ALL RUBBER SEALS AND WORN OR CORRODED PARTS
CLEAN, REMOVE GREASE FROM AFFECTED PARTS WITH SOLVENT
SURFACE PREPARATION IN CAUSTIC SOLUTION TANK. DE-SCALE SURFACES AREA TO REMOVE DIRT SCALE, RUST, AND PAINT
PRESSURE RINSE TO REMOVE CAUSTIC SOLUTION
BUFF REMOVE REMAINING PAINT AND SCALE WITH WIRE BRUSH
VISUAL EXAMINATION OF ALL SURFACES FOR CORROSION AND PITTING
VISUAL ACCEPTABLE?
NO
SCRAP IRON IN DATABASE SO SERIAL BECOMES UNUSABLE
MAKE PARTS WITH ORANGE PAINT TO SIGNIFY SCRAPPING
DISPOSE OF PART OR DELIVER BACK TO CUSTOMER AT REQUEST
YES
LEVEL 3 OR MAGNETIC PARTICLE TESTING AND/OR PAINT
YES
LEVEL 3
NO
REASSEMBLE AND FIT WITH NEW SEALS AND ANY SPARE PARTS REQUIRED
LEVEL 1 PRESSURE TEST

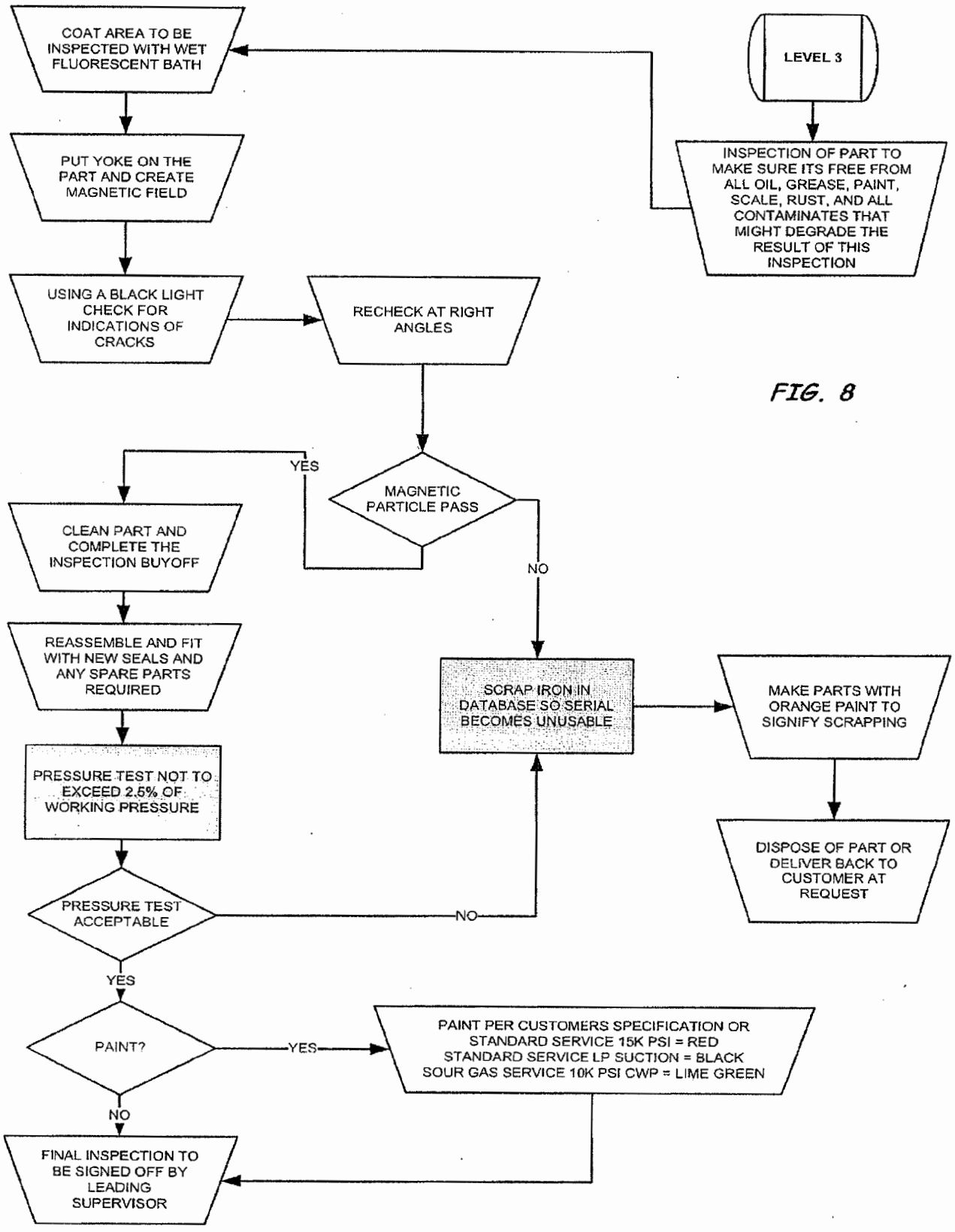

COAT AREA TO BE INSPECTED WITH WET FLUORESCENT BATH
PUT YOKE ON THE PART AND CREATE MAGNETIC FIELD
USING A BLACK LIGHT CHECK FOR INDICATIONS OF CRACKS
RECHECK AT RIGHT ANGLES
MAGNETIC PARTICLE PASS
YES
NO
CLEAN PART AND COMPLETE THE INSPECTION BUYOFF
REASSEMBLE AND FIT WITH NEW SEALS AND ANY SPARE PARTS REQUIRED
PRESSURE TEST NOT TO EXCEED 2.5% OF WORKING PRESSURE
PRESSURE TEST ACCEPTABLE
NO
YES
PAINT?
YES
NO
PAINT PER CUSTOMERS SPECIFICATION OR
STANDARD SERVICE 15K PSI = RED
STANDARD SERVICE LP SUCTION = BLACK
SOUR GAS SERVICE 10K PSI CWP = LIME GREEN
FINAL INSPECTION TO BE SIGNED OFF BY LEADING SUPERVISOR
SCRAP IRON IN DATABASE SO SERIAL BECOMES UNUSABLE
MAKE PARTS WITH ORANGE PAINT TO SIGNIFY SCRAPPING
DISPOSE OF PART OR DELIVER BACK TO CUSTOMER AT REQUEST
LEVEL 3
INSPECTION OF PART TO MAKE SURE ITS FREE FROM ALL OIL, GREASE, PAINT, SCALE, RUST, AND ALL CONTAMINATES THAT MIGHT DEGRADE THE RESULT OF THIS INSPECTION

FIG. 8

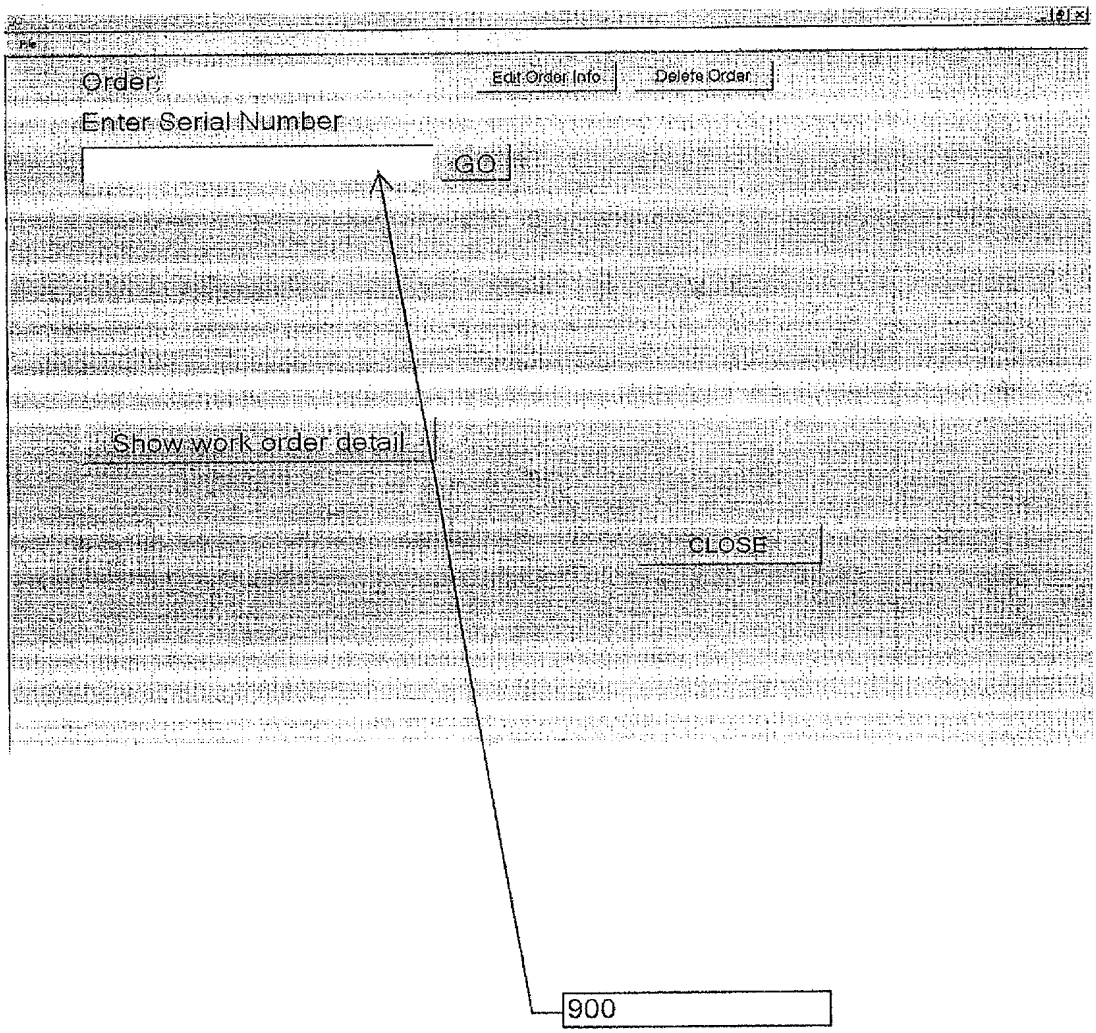

Order:
Edit Order Info
Delete Order
Enter Serial Number
GO
Show work order detail
CLOSE
900

FIG. 9

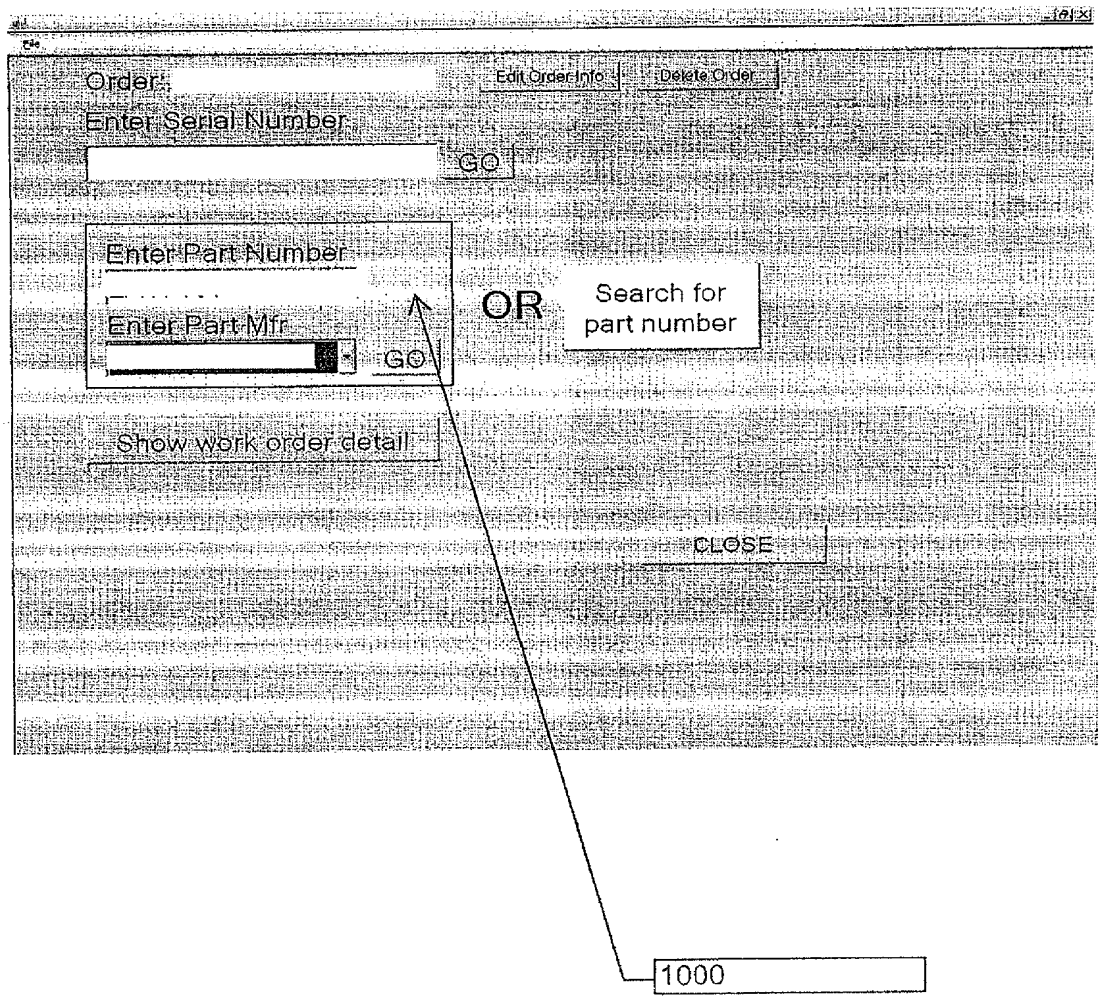

Order:
Edit Order Info
Delete Order
Enter Serial Number
GO
Enter Part Number
Enter Part Mfr
GO
OR
Search for part number
Show work order detail
CLOSE
1000

FIG. 10

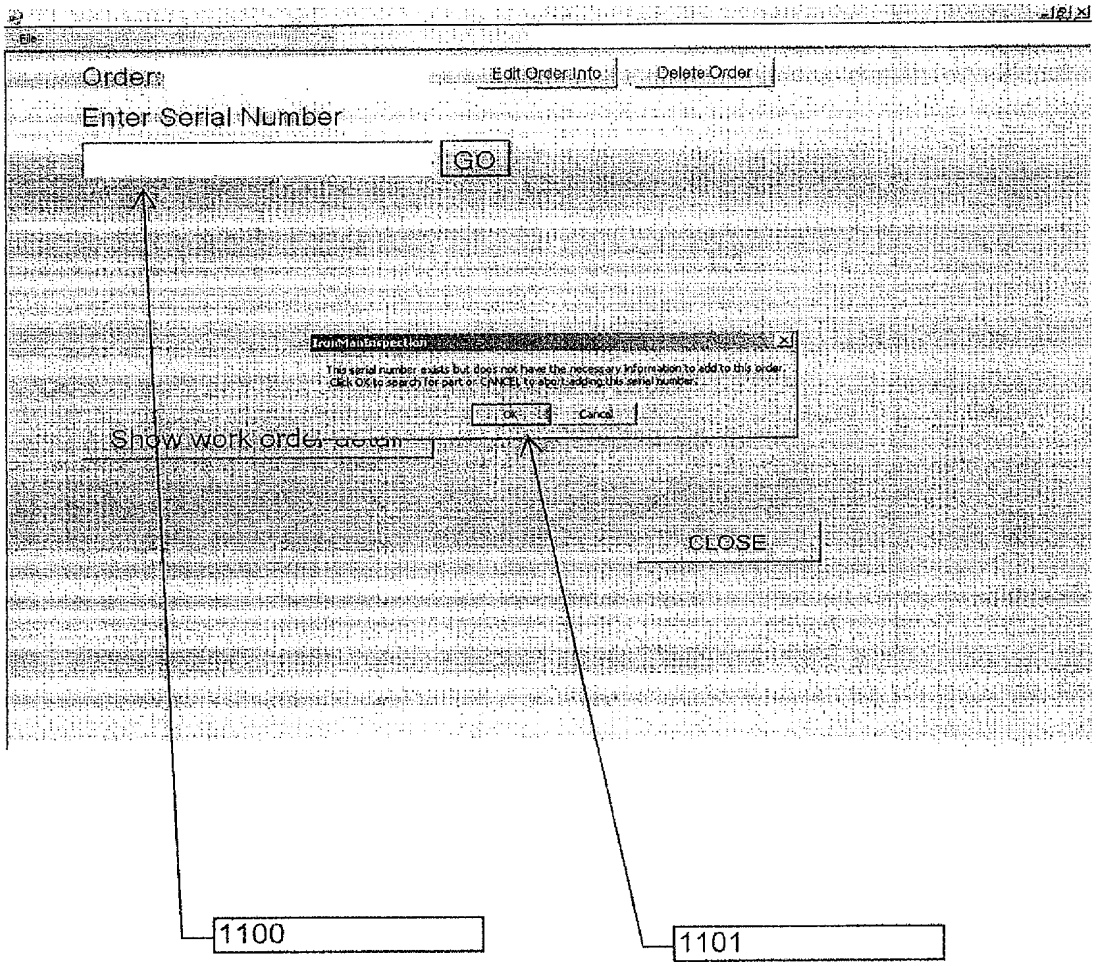

File
Order:
Edit Order Info
Delete Order
Enter Serial Number
GO
This serial number exists but does not have the necessary information to add to this order.
Click OK to search for part or CANCEL to abort adding this serial number.
OK
Cancel
Show work orders
CLOSE
1100
1101

FIG. 11

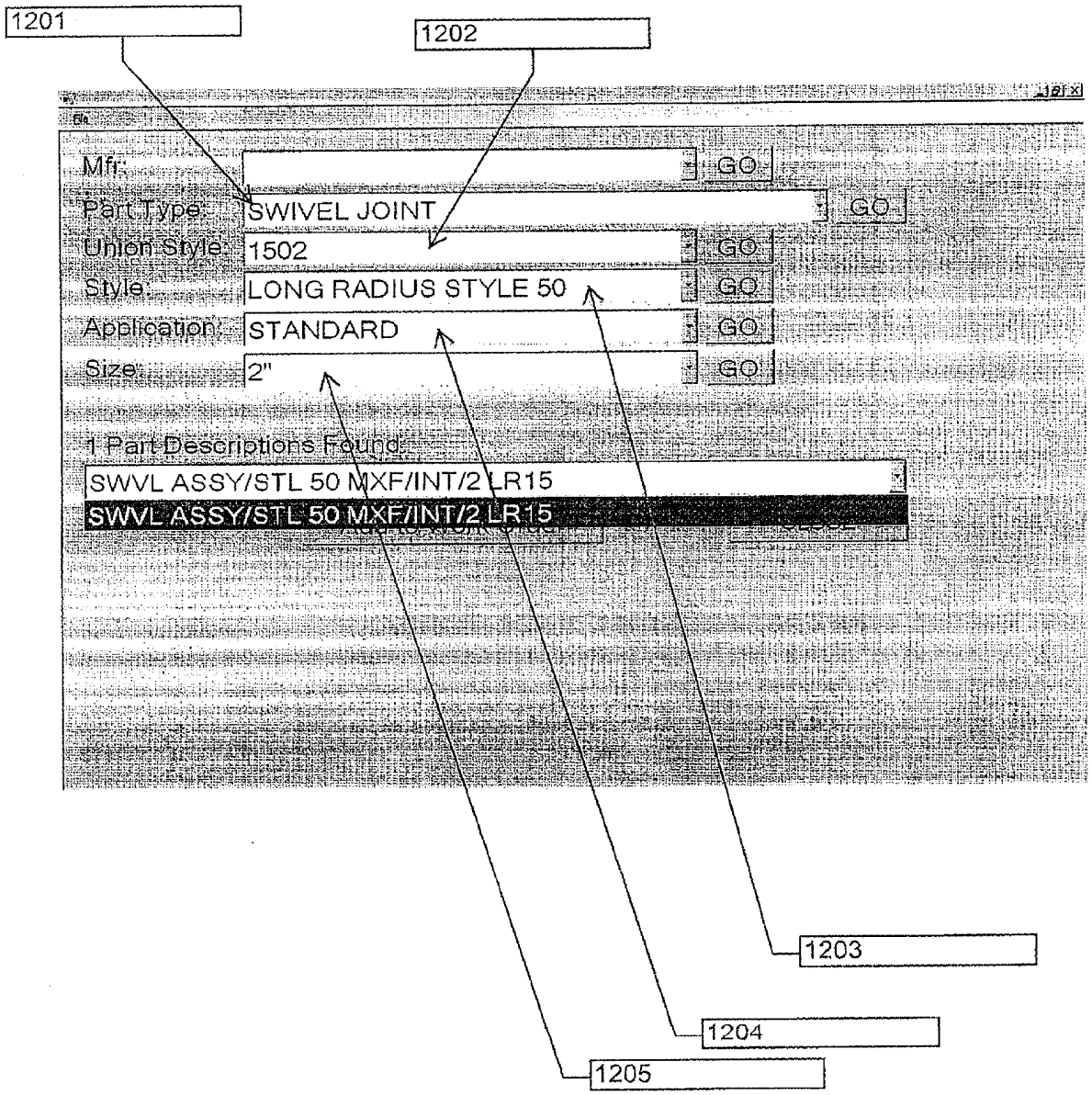

1201
1202
Mfr:
GO
Part Type:
SWIVEL JOINT
GO
Union Style:
1502
GO
Style:
LONG RADIUS STYLE 50
GO
Application:
STANDARD
GO
Size:
2"
GO
1 Part Descriptions Found:
SWVL ASSY/STL 50 MXF/INT/2 LR15
SWVL ASSY/STL 50 MXF/INT/2 LR15
1203
1204
1205

FIG. 12

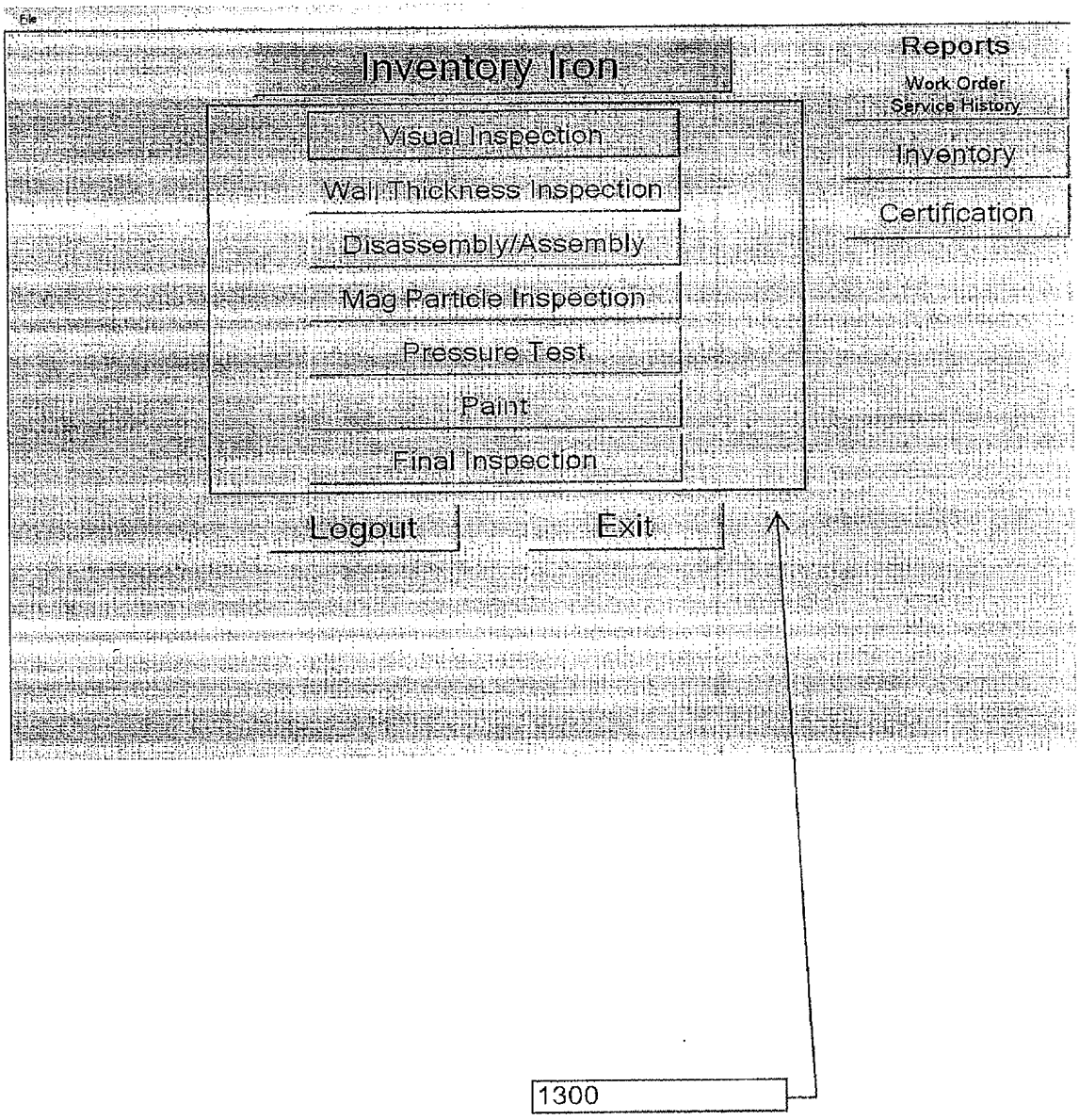

File
Inventory Iron
Visual Inspection
Wall Thickness Inspection
Disassembly/Assembly
Mag Particle Inspection
Pressure Test
Paint
Final Inspection
Logout
Exit
Reports
Work Order
Service History
Inventory
Certification
1300

FIG. 13

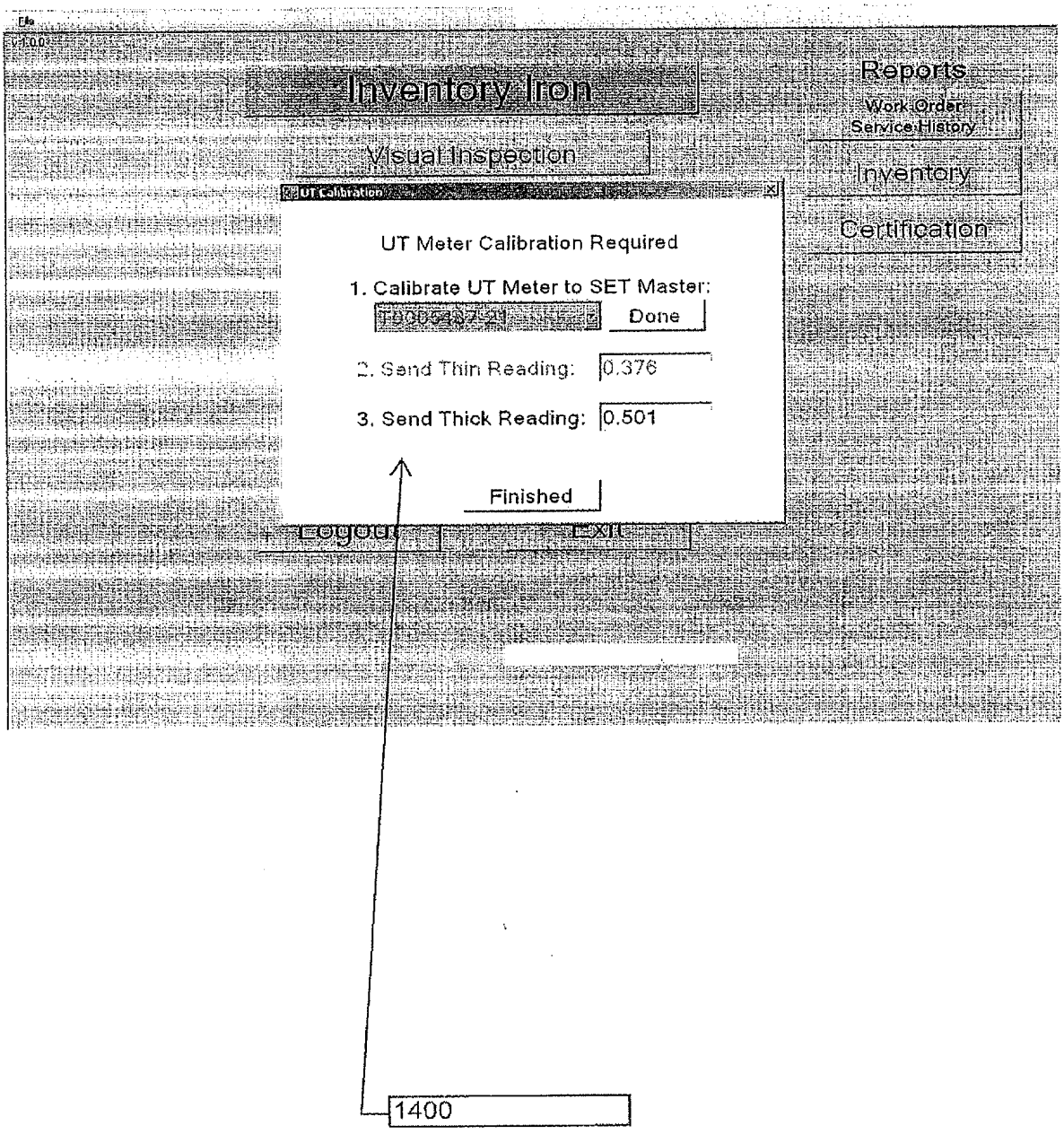

Inventory Ion
Reports
Work Order
Service History
Visual Inspection
Inventory
Certification
UT Calibration
UT Meter Calibration Required
1. Calibrate UT Meter to SET Master:
Done
2. Send Thin Reading:
0.376
3. Send Thick Reading:
0.501
Finished
Logout
Exit
1400

FIG. 14

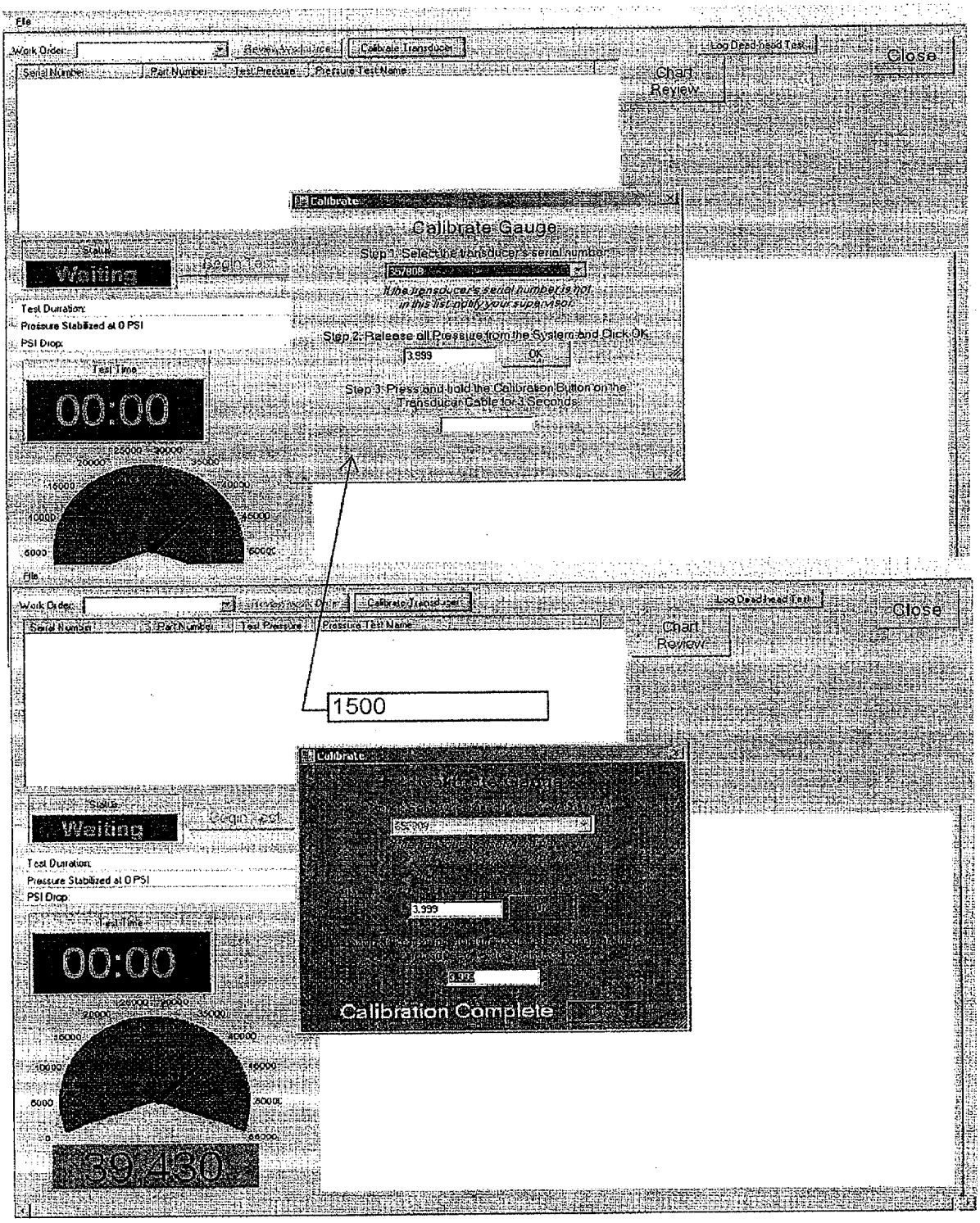

File
Work Order:
Review Work Order
Calibrate Transducer
Log Dead Head Test
Close
Serial Number
Part Number
Test Pressure
Pressure Test Name
Chart Review
Calibrate
Calibrate Gauge
Status
Waiting
Begin Test
Step 1: Select the transducer's serial number
857809
If the transducer's serial number is not in this list, notify your supervisor.
Test Duration:
Pressure Stabilized at 0 PSI
PSI Drop:
Step 2: Release all Pressure from the System and Click OK
3.999
OK
Test Time
00:00
Step 3: Press and hold the Calibration Button on the Transducer Cable for 3 Seconds
1500
Calibration Complete
39.430

FIG. 15

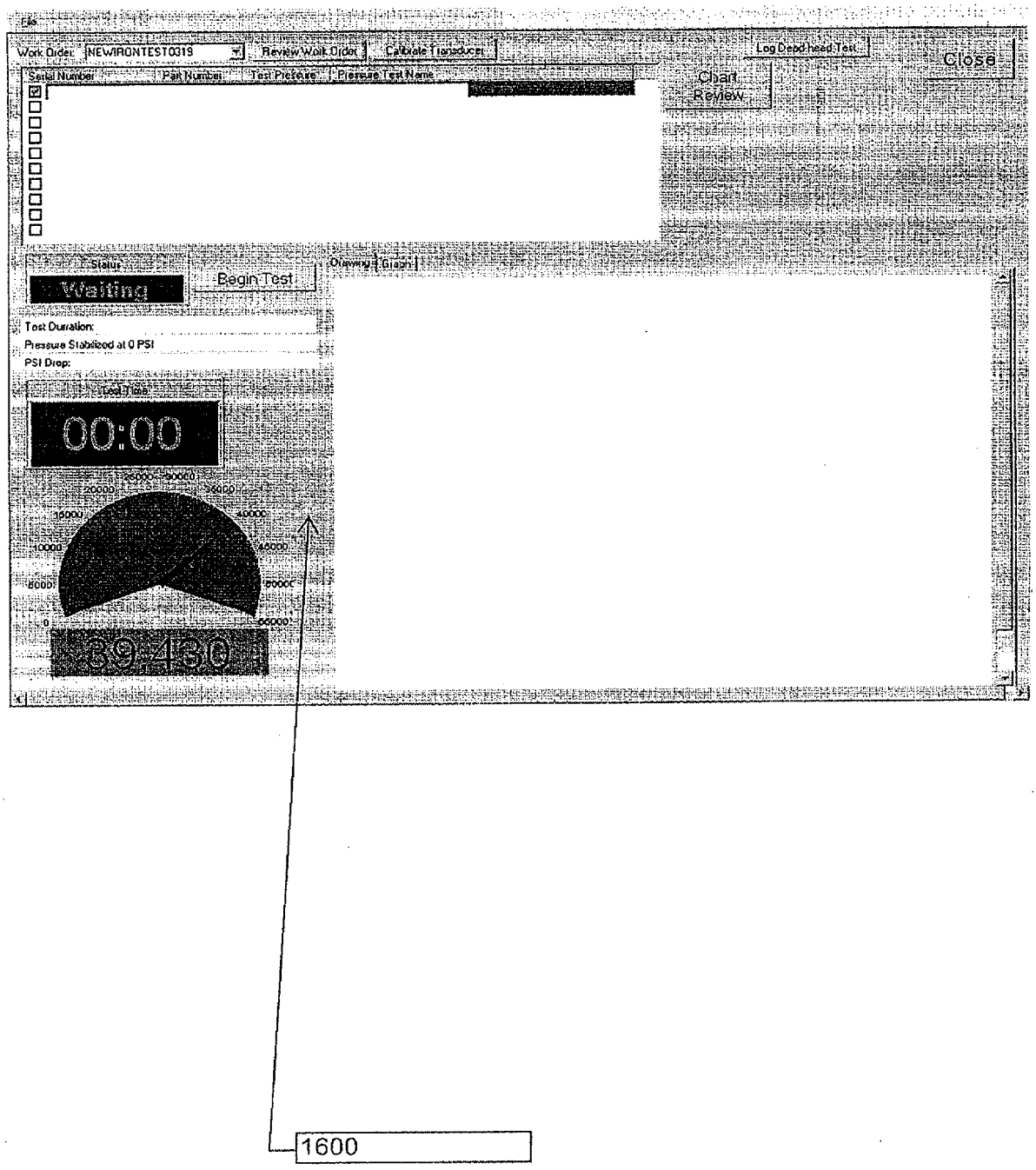

Work Order
NEWIRONTEST0319
Review Work Order
Calibrate Transducer
Log Dead Head Test
Close
Serial Number
Part Number
Test Pressure
Pressure Test Name
Chart Review
Status
Waiting
Begin Test
Drawing Graph
Test Duration:
Pressure Stabilized at 0 PSI
PSI Drop:
Load Test
00:00
89.430
1600

FIG. 16

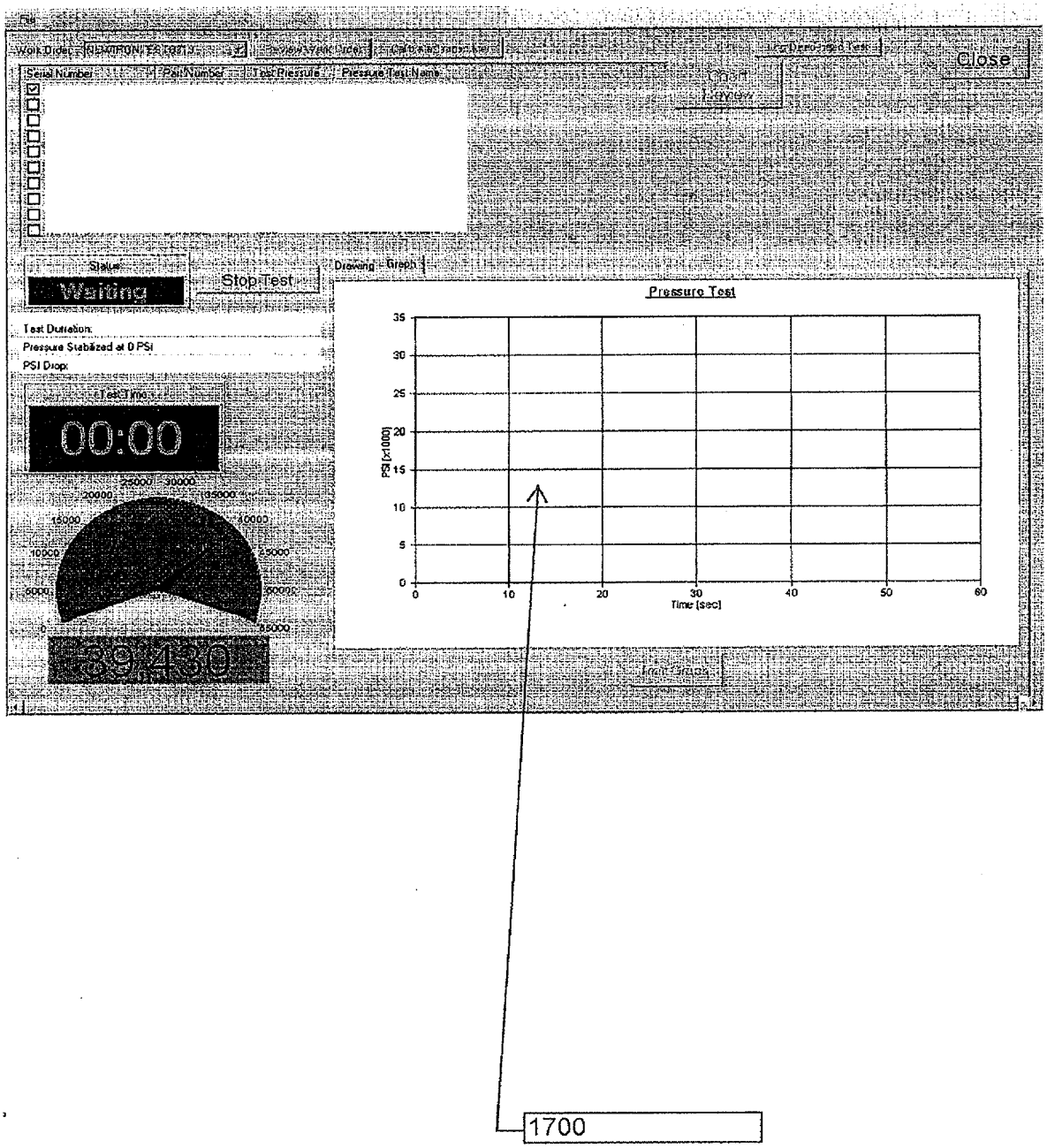

Close
Serial Number
Part Number
Test Pressure
Pressure Test Name
Status
Waiting
Stop Test
Drawing
Graph
Test Duration:
Pressure Stabilized at 0 PSI
PSI Drop:
Test Time
00:00
Pressure Test
PSI (x1000)
Time [sec]
0
5
10
15
20
25
30
35
0
10
20
30
40
50
60
1700

FIG. 17

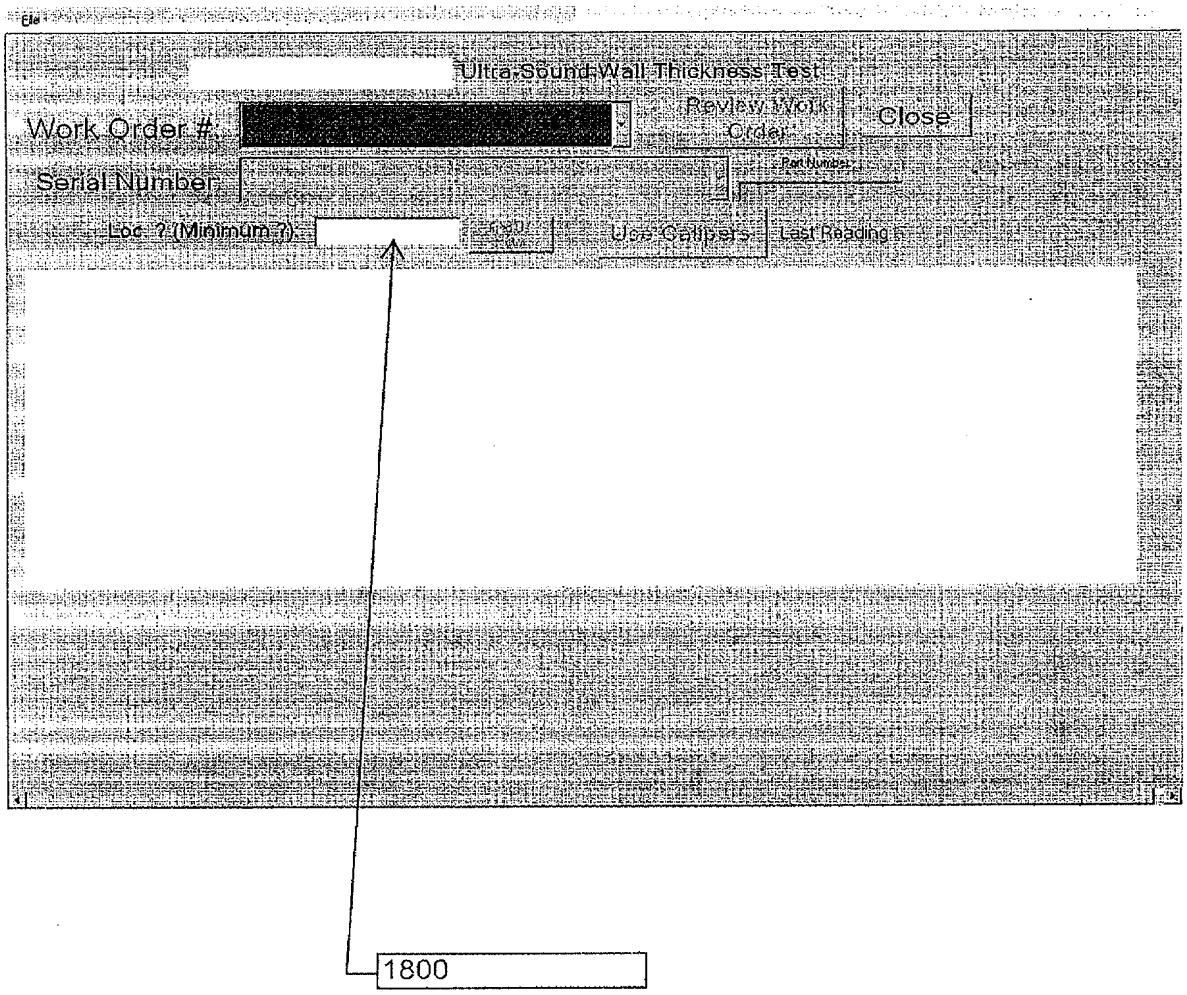

Ultra-Sound Wall Thickness Test
Review Work Order
Close
Work Order #:
Serial Number:
Part Number
Loc ? (Minimum ?):
Use Calipers
Last Reading
1800

FIG. 18

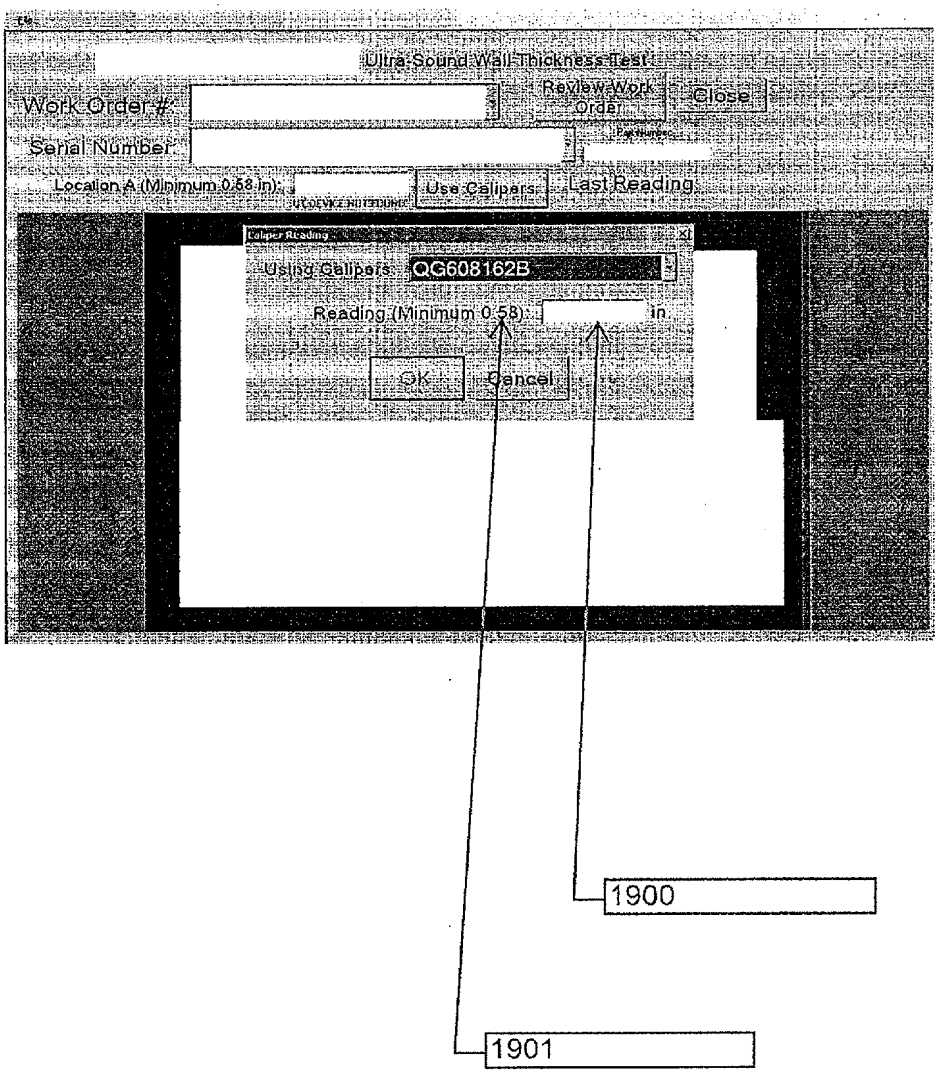

Ultra Sound Wall Thickness Test
Work Order #:
Review Work Order
Close
Serial Number:
Location A (Minimum 0.58 in):
Use Calipers
Last Reading
Using Calipers:
QG608162B
Reading (Minimum 0.58):
in
OK
Cancel
1900
1901

FIG. 19

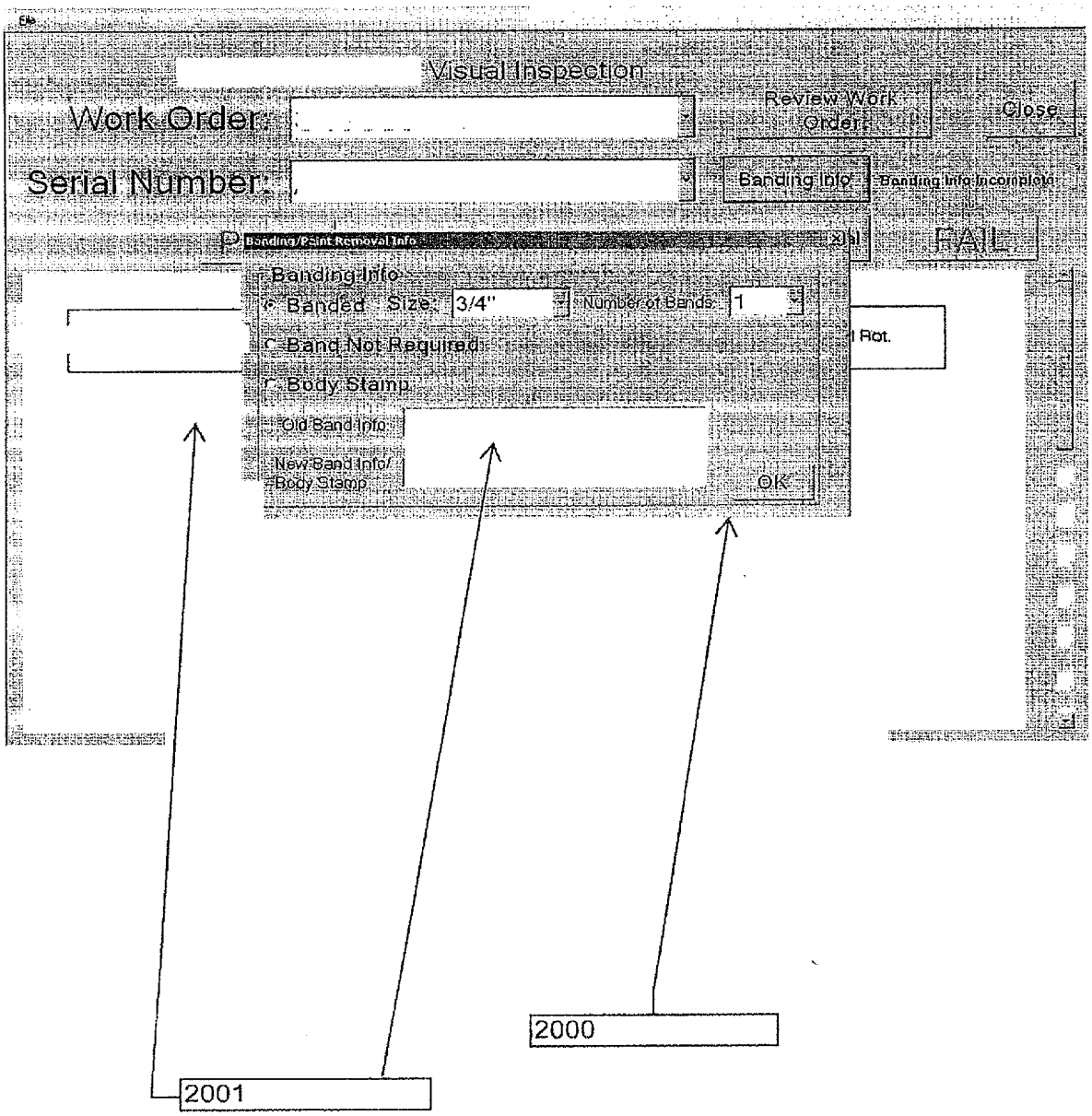

Visual Inspection
Work Order:
Serial Number:
Review Work Order
Close
Banding Info
Banding Info Incomplete
FAIL
Banding/Paint Removal Info
Banding Info
Banded Size: 3/4"
Number of Bands: 1
Band Not Required
Body Stamp
Old Band Info
New Band Info/ Body Stamp
OK
Rot.
2000
2001

FIG. 20

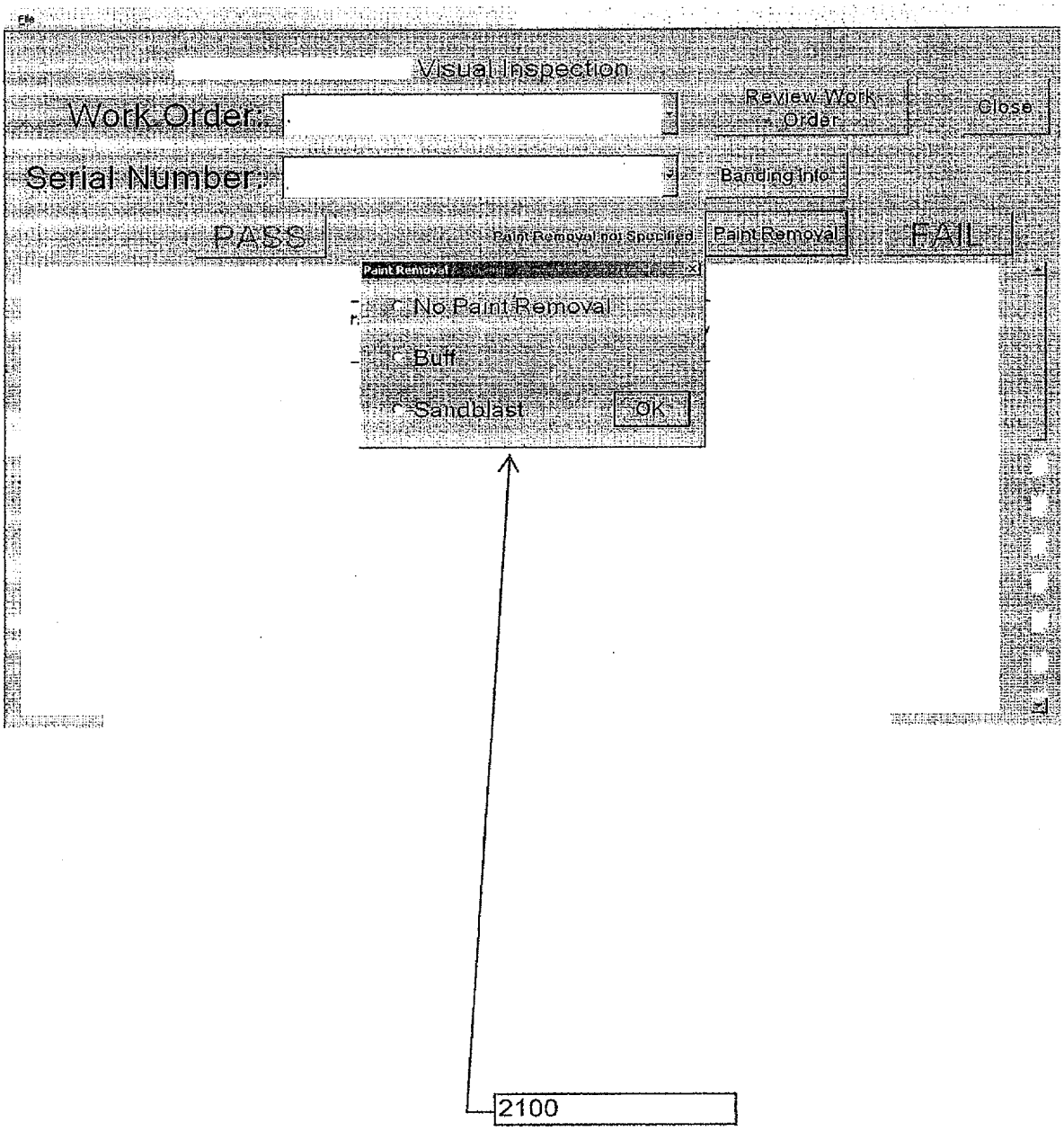

Visual Inspection
Work Order:
Review Work Order
Close
Serial Number:
Banding Info
PASS
Paint Removal not Specified
Paint Removal
FAIL
No Paint Removal
Buff
Sandblast
OK
2100

FIG. 21

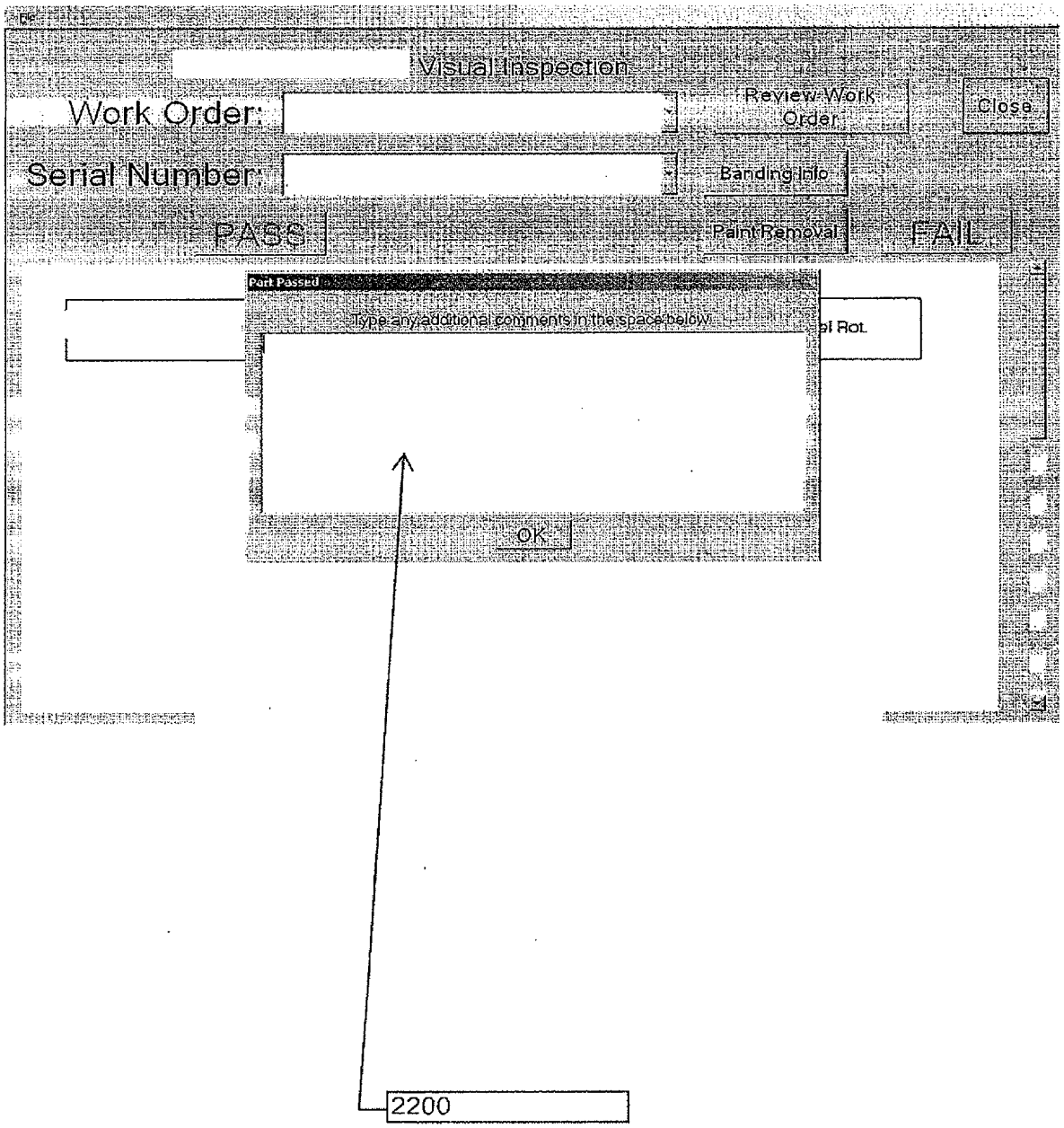

Visual Inspection
Work Order:
Review Work Order
Close
Serial Number
Banding Info
PASS
Paint Removal
FAIL
Part Passed
Type any additional comments in the space below
OK
2200

FIG. 22

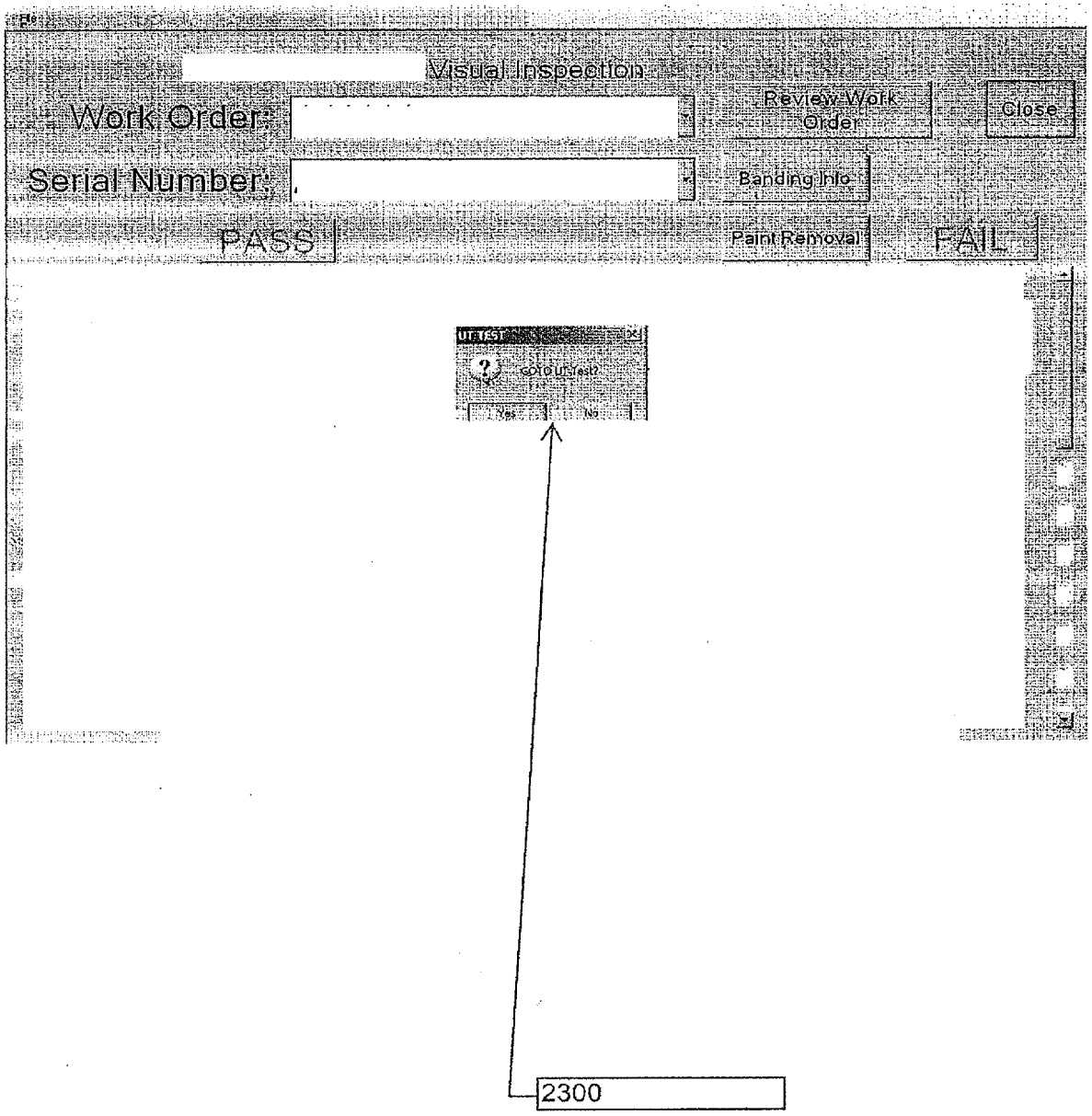

Visual Inspection
Work Order:
Review Work Order
Close
Serial Number:
Banding Info
PASS
Paint Removal
FAIL
2300

FIG. 23

Service Center Service History

Date:	02/24/2010	Customer:	
Location:		Group ID / Unit #:	
Description:	5 piece Rental	Quantity:	6
Inspection:	Rental	Start Date:	02/24/2010
		Finish Date:	
Wo / Sro #:		Approved By:	

Specifications to be followed: SERVICE COMPANY

Product Description

Cust P/N:	100011214	Cust S/N:	TEST003	Size:	1.5"
Mfr P/N:		Mfr S/N:		Style:	DART
				Connections:	UNION CONNECTIONS
Mfr:		Product Type:	CHECK VALVE	Configuration:	F X M

Svc:	
Pressure Rating:	15,000.00
Test Pressure:	15,000.00
Test Duration:	min

Inspections Performed

	Pass/Fail	Inspector	Date
Visual:			
UT Wall Thickness:			
Disembly/Asmbly:	N/A		
Magnetic Particle:	N/A		
Pressure:			
Paint:			
Final:			

Gauges Used

	Serial Number		Serial Number
Calipes:		No Go Gauge Kit:	
UT Meter:			
MPI Equip:			
Pres Gauge:		Pres Recordar:	

Wall Thickness Information

Inspection Point:	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
New Wall Thickness (if reqd):	1.01	0.64	1.19	0.47											
Min Allowable Wall Thick (Spec:	0.72	0.60	1.05	0.33											
Actual Measurement:															

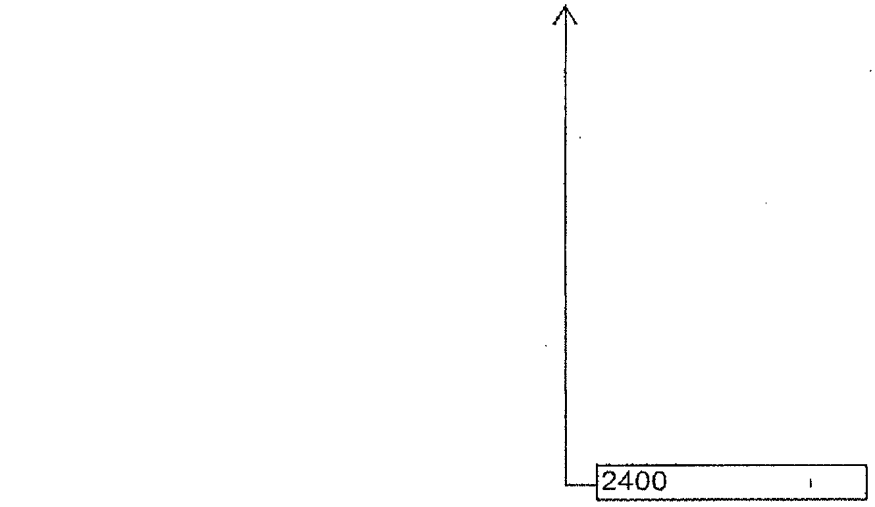


FIG. 24

Iron Inventory

Date: 02/24/2010
Location:
Description: 5 piece Rental
Inspection: Rental
WO / SRO #:

Customer:
Group ID / Unit #:
Quantity: 6
Start Date: 02/24/2010
Finish Date:
Approved By:

Specifications to be followed: SERVICE COMPANY

Serial Number	Part Number	Status	Description
		Visual Inspection (PENDING)	1.5 X 1.5-1502 DART STYLE CHECK VALVE UNION CONNECTIONS
		Visual Inspection (PENDING)	PPG ASSY/2-1502 PS 240.00
		Wall Thickness (PENDING)	SWVL ASSY/STL 10 MXF/INT/2 LR15
		Wall Thickness (PENDING)	SWVL ASSY/STL 50 MXF/INT/2 LR15
		Wall Thickness (PENDING)	SWVL ASSY/STL 50 MXF/INT/2 LR15

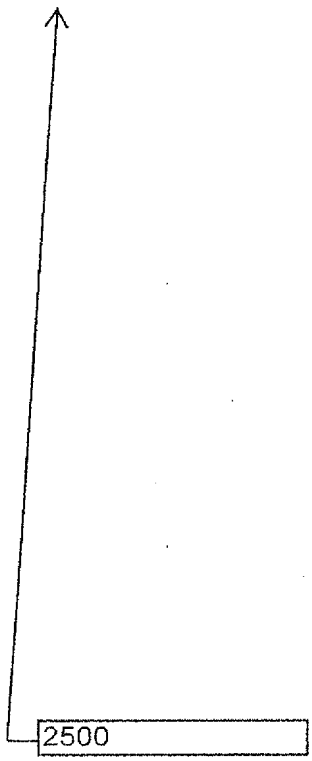
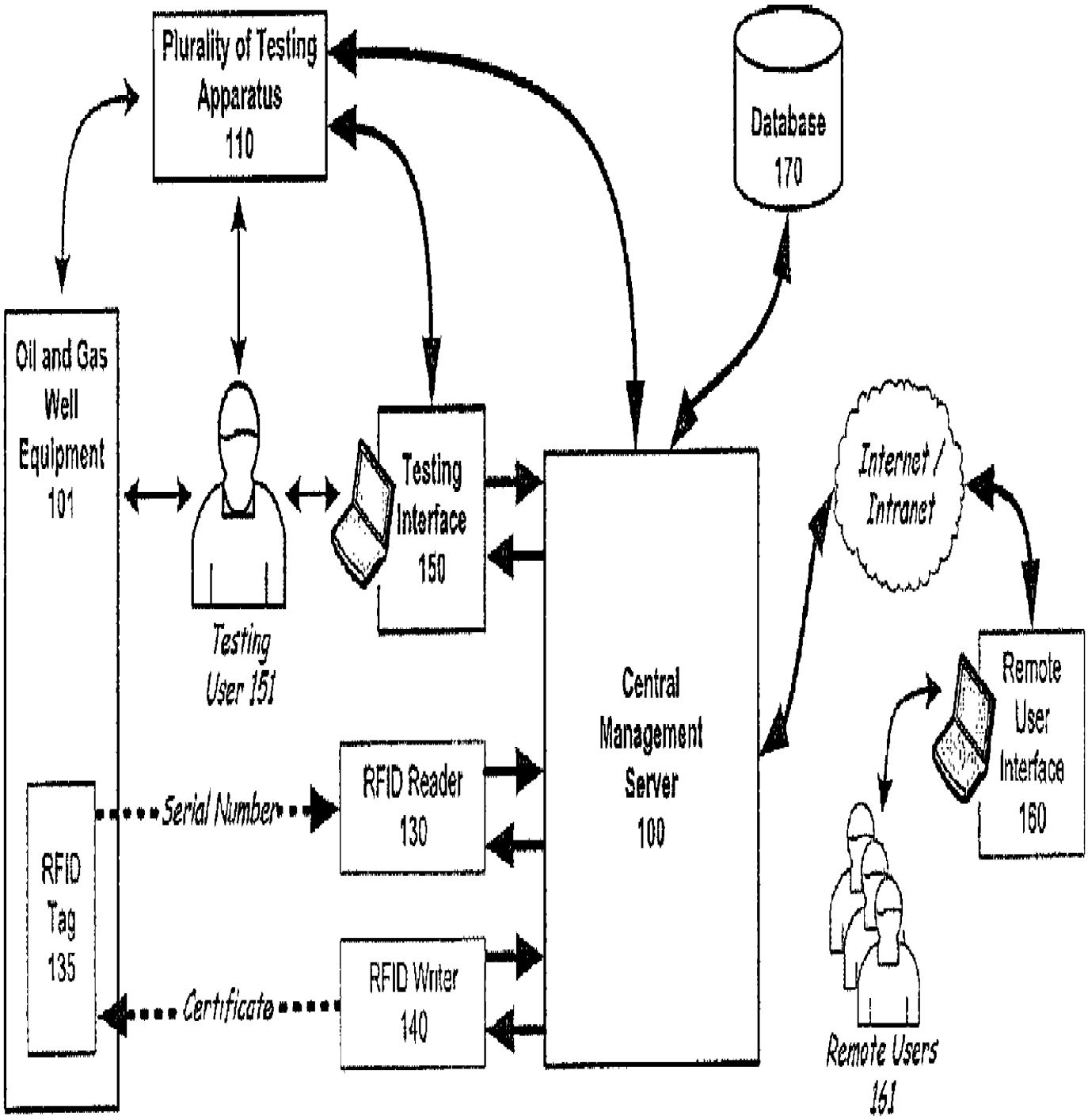


FIG. 25


Plurality of Testing Apparatus 110
Database 170
Oil and Gas Well Equipment 101
Testing Interface 150
Testing User 151
Internet / Intranet
Central Management Server 100
Remote User Interface 160
RFID Tag 135
Serial Number
RFID Reader 130
RFID Writer 140
Certificate
Remote Users 151

Espacenet

Bibliographic data: CN101977016 (A) — 2011-02-16

Singlechip-based induction motor variable frequency speed regulation control system

Inventor(s): FENGYING WU; LIYING JIA; YOUJIE MA; XUESONG ZHOU; JI LI; HULONG WEN ± (WU FENGYING, ; JIA LIYING, ; MA YOUJIE, ; ZHOU XUESONG, ; LI JI, ; WEN HULONG)

Applicant(s): UNIV TIANJIN TECHNOLOGY ± (TIANJIN UNIVERSITY OF TECHNOLOGY)

Classification: **- international:** ***H02H7/08; H02P27/06***
- cooperative:

Application number: CN20101515170 20101022 Global Dossier

Priority number (s): CN20101515170 20101022 ; CN20102571489U 20101022

Also published as: CN201830200 (U)

Abstract of CN101977016 (A)

The invention discloses a singlechip-based induction motor variable frequency speed regulation control system. The system comprises a main circuit, an auxiliary power circuit, an inverter circuit, a control part, an over-current protection circuit, a rotation speed detection circuit and other peripheral circuits. A 16-bit high-performance signal controller dsPIC30F4011 which is produced by the Microchip Company is used as a control core by the system to perform speed regulation based on vector control motor excitation. A digital signal controller dsPIC30F4011 of the America Microchip Technology Company is used as a chip special for motor control, a digital signal processor (DSP) inner core is embedded, and the chip has quick data processing capacity and is provided with abundant input and output equipment and interface circuits; an intelligent power module (IPM) IRAMSIOUP 60A of the IR Company is an inverter switching device, so that the variable frequency speed regulation control system of an asynchronous motor is constructed; and the system has the characteristics that the system is simple to drive and easy to realize.

(19)中华人民共和国国家知识产权局

(12)发明专利申请

(10)申请公布号 CN 101977016 A
(43)申请公布日 2011.02.16

(21)申请号 201010515170.5

(22)申请日 2010.10.22

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(51)Int.Cl.
H02P 27/06(2006.01)
H02H 7/08(2006.01)

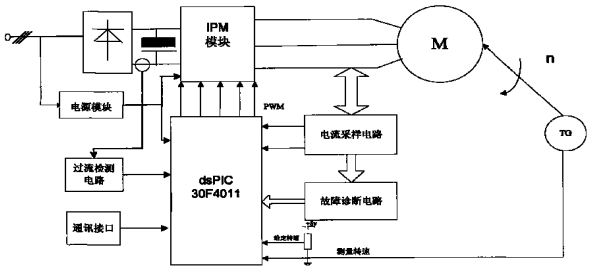
权利要求书 1 页 说明书 8 页 附图 4 页

(54)发明名称

一种基于单片机的感应电机变频调速控制系统

(57)摘要

一种基于单片机的感应电机变频调速控制系统。该系统包括主电路、辅助电源电路、逆变电路、控制部分，过流保护电路、转速检测电路以及其他外围电路。该系统以微芯公司生产的16位高性能信号控制器dsPIC30F4011为控制核心，基于矢量控制电机励磁，进行调速。美国MicrochipTechnology公司的数字信号控制器dsPIC30F4011是电机控制的专用芯片，内嵌DSP内核，具有相当快的数据处理能力和丰富的输入输出设备及接口电路；IR公司的智能功率模块(IPM)IRAMS10UP60A为逆变开关器件，构建了异步电动机的变频调速控制系统，具有驱动简单、易于实现的特点。



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1. 一种基于单片机的感应电机变频调速控制系统，其特征在于，该系统包括主电路、辅助电源电路、控制部分，电流检测电路、转速检测电路以及其他外围电路，具体组成如下：

主电路：以 220V 交流供电，经过单相桥式不可控整流电路和电容滤波，得到平滑的直流电压供给 IPM 模块和辅助电源电路使用；

IPM 模块：逆变部分变频控制最主要的部分之一，它的主要作用是将直流中间电路输出的直流电压换为所需频率的交流电压，给异步电动机供电；

逆变部分：由六个开关器件组成，与开关器件并联的快速恢复二极管用于处理无功电流，称为续流二极管；逆变部分 IGBT 位于逆变桥上，其输入端与电解电容并联，起到缓冲波动和干扰的作用，考虑到经济性安全系数不必取得太大；

控制部分：以 dsPIC30F4011 芯片为核心，外加相电流检测电路、速度检测电路、串口通讯电路、按键和故障保护电路；逆变电路是由 dsPIC30F4011 输出六路 PWM 脉冲信号用于控制 IPM 模块，得到三相可控交流电供给异步电动机；dsPIC30F4011 芯片内集成了一款专用电机控制模块叫 MCPWM 模块，这一设置大大简化了产生 PWM 波形的控制软件和外部硬件，通过编程可产生独立的、具有相同频率和工作方式的三相 6 路 PWM 波形，并由 RE 口直接输出 6 路 PWM 信号给逆变电路，且三相互补不重叠；

故障保护电路：将故障综合后的故障信号送入控制部分，任何一个故障发生，控制部分便关闭 PWM；

电流检测电路：在直流母线上串一个功率电阻，通过该功率电阻把电流信号转换成电压信号，然后再通过运算放大器对信号进行放大后送入控制部分；在主电路进行电流检测时，一旦检测到主电路的电流过流，应该立即封锁控制信号输出，通知控制部分关闭 PWM 并报警；

转速检测电路：是通过电机自带的测速发电机来实现的。

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一种基于单片机的感应电机变频调速控制系统

【技术领域】：

[0001] 本发明属于电机控制、电力电子和微机原理的交叉技术领域，具体涉及以微芯公司生产的 16 位高性能信号控制器 dsPIC30F4011 为控制核心，设计感应电机的变频调速控制系统。

【背景技术】：

[0002] 近年来随着电力电子技术、数字控制技术、控制理论的发展，特别是一些先进控制技术的发明，交流变频调速的发展也越来越快，使交流调速得到越来越广泛的应用，其调速性能也不断提高，克服了许多直流调速难以克服的缺点。第一代变频器采用的是恒压频比控制方式，它根据异步电动机等效电路确定的线性进行变频调速。电压是指基波的有效值，改变 U/f 只能调节电动机的稳态磁通和转矩，谈不上动态控制。第二代变频器的主要特征是采用矢量控制方式，它参照直流电动机的控制方式，将异步电动机的定子电流空间矢量分解为转子励磁分量和转矩分量。此控制方法的主要缺点是需要复杂的坐标变换运算，以及需检测转速信号。因此，进一步提出无速度传感器矢量控制的方法，它根据异步电动机实际运行的相电压和相电流，以及定转子绕组参数推算出转速观测值，以实现磁场定向的矢量控制。由于转速观测值的精度受到所用计算参数与电动机实际运行参数之间偏差大小的影响，所以无速度传感器矢量控制的调速精度和范围，均低于带速度编码器的矢量控制方案。一般前者的调速精度为 1％，输出额定转矩时的最低频率只能达到 1Hz 左右，而后者调速精度为 0.01％，最低频率为 0.1Hz。与矢量控制并行发展的还有直接转矩控制方式，它以异步电动机的转矩作为被控量，强调转矩的直接控制效果，并不刻意追求输出电流为正弦波形。异步电动机的直接转矩控制是直接在定子坐标上计算磁链的幅值和转矩的大小，对其进行直接跟踪调节，以获得迅速的动态响应，其响应速度可小到 1 ～ 2ms。从转矩调控要求看，磁链有点误差，并不会对转矩控制性能产生重大影响。这种控制方式的优点是对电动机参数变化不敏感。

[0003] 近几年来，不依赖电动机模型的模糊自寻优控制、人工神经网络等智能化控制方法开始引入到交流调速系统中，成为交流调速控制理论、控制技术新的研究发展方向。

[0004] 逆变器从采用晶闸管半控器件到采用 GTR 全控器件，其输出波形从交流方波发展为脉宽调制 (PWM) 波形，大大减小了谐波分量，拓宽了异步电动机变频调速范围，并减小了转矩的脉动幅度。然而，GTR 工作频率一般在 2kHz 以下，载波频率和最小脉宽都受到限制，难以得到较为理想的正弦波脉宽调制波形，使异步电动机在变频调速时产生噪声。IGBT 的工作频率可在 10 ～ 20kHz 之间，与 GTR 相比，不仅工作频率高出一个数量级，而且在电压和电流指标均已超出 GTR。由于逆变器载波频率的提高，以及可以构成特定的 PWM 波形，异步电动机变频调速控制器的谐波噪声大为降低。智能功率模块 (IPM) 是以 IGBT 为开关器件，同时含有驱动电路和保护电路的一种功率集成器件 (PIC)。IPM 的保护功能有过电流、短路、欠电压、过电压和过热等，还可以实现再生制动。由 IPM 组成的逆变器只需对桥臂上各个 IGBT 提供隔离的 PWM 信号即可。简单的外部电路和控制电路的集成化，使变频器体积

大为减小。还有，由于功率开关器件的故障检测和保护电路接近故障点，故可以抑制故障扩大，保证装置可靠运行。

[0005] 数字化使得控制器对信息的处理能力大幅度提高，许多难以实现的复杂控制，采用微机控制器后便都解决了。高性能的矢量控制系统，如果没有微机的支持是不可能真正实现的。此外，微机控制技术给交流调速系统增加了多方面的功能，特别是故障诊断技术得到了完全的实现。

[0006] 微机控制技术及大规模集成电路的应用提高了交流调速系统的可靠性，操作、设置的多样性和灵活性，降低了变频器调速装置的成本和体积。实践表明，调速控制装置中所采用的微处理器的性能将直接影响到装置性能。

【发明内容】：

[0007] 本发明目的是克服现有调速系统的不足，提供一种基于单片机的感应电机变频调速控制系统。

[0008] 本发明采用高性能微处理器可以简化装置结构、完善装置功能、实现复杂有效的控制策略以及提高控制装置的可靠性。美国 MicrochipTechnology 公司的数字信号控制器 dsPIC30F4011 是电机控制的专用芯片，内嵌 DSP 内核，具有相当快的数据处理能力和丰富的输入输出设备及接口电路，因而本发明选用它作为核心控制器件来构成控制回路。在主回路中，采用 IR 公司的智能功率模块 (IPM) IRAMSIOUP60A[40] 为逆变开关器件，构建了异步电动机的变频调速控制系统。

[0009] 本发明的技术方案 ：

[0010] 本发明提供的基于单片机的感应电机变频调速控制系统是一个典型的交一直一交变压变频结构，整个控制系统以 dsPIC30F4011 芯片为核心，包括主电路、辅助电源电路，控制部分，过电流保护电路，转速检测电路以及其他外围电路，具体组成如下 ：

[0011] 主电路 ：以 220V 交流供电，经过单相桥式不可控整流电路和电容滤波，得到平滑的直流电压供给 IPM 模块和辅助电源电路使用 ；

[0012] IPM 模块 ：逆变电路是变频控制最主要的部分之一，它的主要作用是将直流中间电路输出的直流电压 (电流) 转换为所需频率的交流电压 (电流)，给异步电动机供电。逆变电路由六个开关器件组成，与开关器件并联的快速恢复二极管用于处理无功电流，称为续流二极管。逆变部分 IGBT 位于逆变桥上，其输入端与电解电容并联，起到缓冲波动和干扰的作用，考虑到经济性安全系数不必取得太大。IR 公司生产的智能模块 (IPM) IRAMSIOUP60A[40]，它的耐压值为 600V，额定电流为 10A。它是向第四代器件功率集成电路 (PIC) 的过渡产品，是微电子技术和电力电子技术相结合的产物。IPM 具有以下特点 ：(1) 开关速度快，驱动电流小，控制驱动更为简单 ；(2) 采用了隔离技术，散热更加均匀，体积更加紧凑 ；(3) 集成度高，它在片内集成了驱动电路、保护电路、甚至光耦，大大缩短开发时间 ；(4) 内含电流传感器，可以高效迅速地检测出过电流和短路电流，能对功率芯片给予足够的保护，故障率大大降低 ；(5) 保护功能丰富，如电流保护、电压保护、温度保护等一应俱全，实现了信号处理、故障诊断、自我保护等多种智能功能，既减小了体积、减轻了重量，又提高了可靠性 ；(6) 由于在器件内部电源电路和驱动电路的配线设计上做到优化，所以浪涌电压，门极振荡，噪声引起的干扰等问题能得到有效的控制 ；(7) 很高的性价比，IPM 的售价已

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经逐渐接近 IGBT，而采用 IPM 后的开关电源容量、驱动功率容量的减小和器件的节省以及综合性能的提高等因素使得 IPM 构成的变频器性价比已经高于 IGBT 构成的变频器，有很好的经济性。

[0013] 控制部分：以 dsPIC30F4011 芯片为核心，外加相电流检测电路、速度检测电路、串口通讯电路、按键和故障保护电路；由 dsPIC30F4011 芯片输出六路 PWM 脉冲信号用于控制 IPM 模块逆变部分，得到三相可控交流电供给异步电动机；

[0014] dsPIC30F4011 芯片内集成了一款专用电机控制模块叫 MCPWM 模块，这一设置大大简化了产生 PWM 波形的控制软件和外部硬件，通过编程可产生独立的、具有相同频率和工作方式的三相 6 路 PWM 波形，并由 RE 口直接输出 6 路 PWM 信号给逆变器，且三相互补不重叠。我们只需定义各个寄存器值便可以产生理想的 PWM 信号，同时为防止同一桥臂上两个功率管发生直通造成短路，该发生器还可通过编程设置死区互锁时间。

[0015] 故障保护电路：将故障综合后的故障信号送入控制部分，任何一个故障发生，控制部分便关闭 PWM 脉冲信号。

[0016] 电流检测电路：在直流母线上串一个很小的功率电阻，通过该功率电阻把电流信号转换成电压信号，然后再通过运算放大器对信号进行放大后送入控制部分；过流是引起功率驱动器被烧坏和损坏的主要原因之一。在主电路进行电流检测时，一旦检测到主电路的电流过流，应该立即封锁控制信号输出，通知控制部分关闭 PWM 并报警。

[0017] 转速检测电路：是电机自带的测速发电机来实现的。

[0018] 整流电路一般分为可控整流和不控整流，其中可控整流又分为全控整流和半控整流。在全控整流电路中，整流器件全部有晶闸管或其他可控器件组成，半控整流电路则由二极管和晶闸管混合组成；不可控整流电路全部由整流二极管组成。本发明的整流部分全部应用整流二极管进行单相不可控桥式整流，这样可有效抑制可控整流中因相控角的变化而引起的谐波，同时也能提高调速装置的功率因数。

[0019] 装置中 dsPIC30F4011 芯片需要 +5V 供电电源，而智能模块 IPM 需要 +15V 电源，所以设计辅助电源来满足此要求，选用了 ST 公司生产的 VIPER12A 芯片，它可以把约 300V 的直流电转换为 +15V 直流电，然后再用 LM7805 把 +15V 转换为 +5V 电源，以提供给各个芯片。

[0020] 本发明的优点和积极效果：

[0021] 本发明以微芯公司生产的 16 位高性能信号控制器 dsPIC30F4011 为控制核心，基于矢量控制电机励磁，进行调速。

[0022] 采用美国 MicrochipTechnology 公司的数字信号控制器 dsPIC30F4011 是电机控制的专用芯片，内嵌 DSP 内核，具有相当快的数据处理能力和丰富的输入输出设备及接口电路。所说的 DsPIC30F4011 内集成了一款专用电机控制模块叫 MCPWM 模块，这一设置大大简化了产生 PWM 波形的控制软件和外部硬件，通过编程可产生独立的、具有相同频率和工作方式的三相 6 路 PWM 波形，并由 RE 口直接输出 6 路 PWM 信号给逆变器，且三相互补不重叠。只需定义各个寄存器值便可以产生理想的 PWM 信号，同时为防止同一桥臂上两个功率管发生直通造成短路，该发生器还可通过编程设置死区互锁时间。

[0023] 采用 IR 公司的智能功率模块 (IPM) IRAMSIOUP60A 为逆变开关器件，构建了异步电动机的变频调速控制器，具有以下特点：(1) 开关速度快，驱动电流小，控制驱动更为简单；(2) 采用了隔离技术，散热更加均匀，体积更加紧凑；(3) 集成度高，它在片内集成了驱动电

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路、保护电路、甚至光耦，大大缩短开发时间；(4) 内含电流传感器，可以高效迅速地检测出过电流和短路电流，能对功率芯片给予足够的保护，故障率大大降低；(5) 保护功能丰富，如电流保护、电压保护、温度保护等一应俱全，实现了信号处理、故障诊断、自我保护等多种智能功能，既减小了体积、减轻了重量，又提高了可靠性；(6) 由于在器件内部电源电路和驱动电路的配线设计上做到优化，所以浪涌电压，门极振荡，噪声引起的干扰等问题能得到有效的控制；(7) 很高的性价比，IPM 的售价已经逐渐接近 IGBT，而采用 IPM 后的开关电源容量、驱动功率容量的减小和器件的节省以及综合性能的提高等因素使得 IPM 构成的变频器性价比已经高于 IGBT 构成的变频器，有很好的经济性。

【附图说明】：

[0024] 图 1 为控制系统总体结构；

[0025] 图 2 为 dsPIS30F4011 结构框图；

[0026] 图 3 为逆变电路 IPM 内部结构和外部连接图；

[0027] 图 4 为转速检测硬件电路图。

[0028] 图 5 为整流电路结构图；

[0029] 图 6 为用 VIPER12A 组建的整个辅助电源电路；

[0030] 图 7 为电流采样电路；

[0031] 图 8 为电流检测电路。

【具体实施方式】：

[0032] 实施例 1：

[0033] 下面结合附图对本设计做进一步描述：控制系统总体结构如图 1 所示，主电路以 220V 交流供电，经过单相桥式不可控整流、电容滤波，得到平滑的直流电压供给 IPM 模块和辅助电源电路使用。

[0034] 逆变电路部分，是由 dsPIC30F4011 输出六路 PWM 脉冲信号控制 IPM 模块，得到三相可控交流电供给异步电动机。

[0035] 控制部分，是以 dsPIC30F4011 芯片为核心，外加相电流检测电路、速度检测电路、串口通讯电路、按键和故障保护电路。

[0036] 故障保护电路将故障综合后的故障信号送入控制部分，任何一个故障发生，便关闭 PWM。

[0037] 过电流检测电路是通过电阻把电流信号转换成电压信号，然后再通过运算放大器对信号进行放大后送入控制芯片。

[0038] 转速检测电路是通过电机自带的测速发电机来实现的。

[0039] 如图 2 为 dsPIC30F4011 结构框图。dsPIC30F 系列 CPU 模块采用 16 位改进型哈佛结构，并带有增强型指令集，包含对 DSP 的有力支持。CPU 指令宽度 24 位，PC 宽度为 23 位，可寻址高达 24X4M 位程序空间。共有 16 个 16 位工作寄存器，每个寄存器都可作为数据、地址或地址偏移寄存器。该系列数字信号控制器具有丰富的指令集，包括多种寻方式，且大多为单周期指令，大大加快了单片机的运行速度。指令主要分为 MCU 类型和 DSP 类型两大类，这两类指令可以有机地集合到构架中，并在同一个执行单元中执行。它还支持 C 语言编译

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器编程，易于开发。dsPIC30F 系列 CPU 内部自带存储容量大，RAM 最高可达 64KB。数据空间可作为 32K 字或 64K 字节寻址，并分为两块 :X 和 Y 数据存储器。每个存储器块有各自的地址发生单元 (AGU)。MCU 类指令只能通过 X 存储器 AGU 进行操作，可将整个存储器空间作为一个线性空间访问。某些带双操作数的 DSP 类型指令通过 X 和 Y 的 AGU 读两个操作数。另外，可将数据存储器空间的高 32KB 映射到 8 位程序空间可视性页面 (PSVPAG)。DsPIC30F4011 内集成了一款专用电机控制模块 - 电机控制脉宽调制 (CPwM) 模块，这一设置大大简化了产生 PWM 波形的控制软件和外部硬件，通过编程可产生独立的、具有相同频率和工作方式的三相 6 路 PWM 波形，并由 RE 口直接输出 6 路 PWM 信号给逆变器，且三相互补不重叠。我们只需定义各个寄存器值便可以产生理想的 PWM 信号，同时为防止同一桥臂上两个功率管发生直通造成短路，该发生器还可通过编程设置死区互锁时间。

[0040] 如图 3 所示 :逆变电路是变频控制最主要的部分之一，主要作用是将直流中间电路输出的直流电压（电流）转换为所需频率的交流电压（电流），给异步电动机供电。逆变部分由六个开关器件组成，与开关器件并联的快速恢复二极管用于处理无功电流，称为续流二极管。逆变部分 IGBT 的电压选择与整流二极管最大的不同是，整流二极管的输入直接与电网相连，电网易受到外界的干扰，因此选择的安全系数口较大 ;而 IGBT 位于逆变桥上，其输入端与电解电容并联，起到缓冲波动和干扰的作用，考虑到经济性安全系数不必取得太大，IGBT 的额定电压 U 可以按式 (3) 来选择 :

[0041] $U \geqslant (U_{DC} \times 1.15+150) \times a$

[0042] 式中 U_{DC} 是直流侧电压 ;1.15 是过电压系数 ;150 是由 $L\frac{di}{dt}$ 引起允许的尖峰电压 ; a 是安全系数，一般取 1.1。对单相交流 220V 输入电压，U_{DC} = 311V，这样得 IGBT 的额定电压 U ≥ 558V。额定电流值 I_C，可按式 (4) 选择 :

[0043] $$I_C = \frac{\sqrt{2} \times 1.5 \times 1.4}{0.9} \times I_N \qquad (4)$$

[0044] 其中，0.9 为电网电压向下的波动系数 ;1.5 为过载 50％允许运行 1 分钟的系数，1.4 为温度的影响系数。由电机铭牌得到 I = 2.5A，选用 IR 公司生产的智能模块 (IPM) IRAMSIOUP60A[40]，它的耐压值为 600V，额定电流为 IOA。它是向第四代器件功率集成电路 (PIC) 的过渡产品，是微电子技术和电力电子技术相结合的产物。它不但提供一定的功率输出能力，而且具有逻辑、控制、传感、检测、保护和自诊断等功能。

[0045] 图 3 为逆变电路 IPM 模块的内部结构和外部连接图，单电源 +15V 驱动，dsPIC30F4011 发出的 PWM 脉冲控制六个 IGBTN 极的开通和关断。P+ 为整流后的直流输入，N- 为接地端。VDD 为芯片的工作电压。输入的方波信号经驱动 IC 来控制逆变桥 IGBT 的通断。当 T/Itrip 输入高电平时内部驱动就会停止工作，从而达到保护芯片的作用。选用的 IR 公司生产的智能模块 (IPM) IRAMSIOUP60A[40]，它的耐压值为 600V，额定电流为 IOA。它是向第四代器件功率集成电路 (PIC) 的过渡产品，是微电子技术和电力电子技术相结合的产物。它不但提供一定的功率输出能力，而且具有逻辑、控制、传感、检测、保护和自诊断等功能。IPM 具有以下特点 :

[0046] (1) 开关速度快，驱动电流小，控制驱动更为简单 ;

[0047] (2) 采用了隔离技术，散热更加均匀，体积更加紧凑 ;

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[0048] (3) 集成度高，它在片内集成了驱动电路、保护电路、甚至光耦，大大缩短开发时间；

[0049] (4) 内含电流传感器，可以高效迅速地检测出过电流和短路电流，能对功率芯片给予足够的保护，故障率大大降低；

[0050] (5) 保护功能丰富，如电流保护、电压保护、温度保护等一应俱全，实现了信号处理、故障诊断、自我保护等多种智能功能，既减小了体积、减轻了重量，又提高了可靠性；

[0051] (6) 由于在器件内部电源电路和驱动电路的配线设计上做到优化，所以浪涌电压，门极振荡，噪声引起的干扰等问题能得到有效的控制；

[0052] (7) 很高的性价比，IPM 的售价已经逐渐接近 IGBT，而采用 IPM 后的开关电源容量、驱动功率容量的减小和器件的节省以及综合性能的提高等因素使得 IPM 构成的变频器性价比已经高于 IGBT 构成的变频器，有很好的经济性。IRAMS10UP60A 使用参数见表：

[0053]

参数	描述	最大值	单位
Vbus	最大直流母线电压	450	V
Vces	最大 IGBT 导通电压	600	V
Io@Tc = 25℃	相电流均方值	10	A
Io@Tc = 100	相电流均方值	4.5	A
Ipk	最大相电流峰值	15	A
Fp	最大 PWM 载波频率	20	KHz
Pd	每相最大功耗	10	W
Rthj-c	每个 IGBT 热阻	4.5	℃ /W
Viso	绝缘电压	2000	Vrms
Tc	工作壳温	-20-+100	℃
Tj	工作壳温	-20-+150	℃
T	安装扭矩范围	0.8-1.0	Nm

[0054] 图 4 所示：转速检测硬件电路。电机自身带有测速发电机，电机每转一圈，都会送出 8 个触发脉冲，测速发电机输出八个脉，通过计算脉冲的时间便可以得到转速。电机每转一圈，这个电路可以输出的脉冲进行整形，输出标准方波。再送入芯片中测出其速度。通过上拉电阻把其电压值进行提升，然后通过两级低通滤波器滤除高频干扰，在这里选用 RC 低通滤波器。此处采用了 LM393 等组成的滞回比较器把正弦波转换为方波，由于它是 OC 门输

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出，所以需要对其进行上拉，此信号便可以送入芯片端口了。

[0055] 如图 5 所示：本设计中的整流部分全部应用整流二极管进行单相不可控桥式整流，这样可有效抑制可控整流中因相控角的变化而引起的谐波，同时也能提高调速系统的功率因数。其为单相不可控桥式电路，其中整流二极管的选择是比较关键的问题，耐压按式 (1) 选择：

[0056] $$U_{RPM}=U_{AC}\times\sqrt{2}\times1.1a \quad (1)$$

[0057] 其中 U_{AC} 为电网电压，考虑到其峰值的波动、闪电雷击等因素，取波动系数为 1.1，安全系数 a = 2，在交流电网电压为 220V 时，U_{RPM} = 684V，所以取二极管的耐压等级为 800V。整流二极管的额定电流按式 (2) 确定：

[0058] $$I \geq 2\sqrt{2}I_N \quad (2)$$

[0059] 式中 I_N 为电机的额定电流值。由电机铭牌得到 I_N = 2A，I = 2.5A. 而整流模块 KBJ1508 的电压电流限度为 800V，15A，根据以上的计算选用整流模块 KBJ1508。

[0060] 滤波电路由一个滤波电容构成，这个电容容量足够大，从逆变器向整流电路全波整流后的直流电源看过去电源内阻很小，近似恒压源，保证直流电压稳定。当系统接入 220 交流电，整流后电压的峰值为 311V，考虑电网电压的波动范围 ±10％，电容的耐压应大于 $1.1\sqrt{2}U=342V$，电容应满足 RC = (3-5)T/2 的条件，C = 285-476Uf。故我们选择 470uF/450V 的滤波电容。

[0061] 如图 6 所示：系统中 dsPIC30F4011 需要 +5V 供电电源，而智能模块 IPM 需要 +15V 电源，所以我们设计辅助电源来满足此要求。这里选用了 ST 公司生产的 VIPER12A 芯片，它可以把约 300V 的直流电转换为 +15V 直流电，然后再用 LM7805 把 +15V 转换为 +5V 电源，以提供给各个芯片。用 VIPER12A 构成的整个辅助电源电路，此电路中稳压元件采用 LM7805，D9 采用 IN4148，D6、D7 采用 STTH1L06U，以满足高频低耗的需要，L1 为高频滤波电感，在这里选用 1.8mH/500mA 电感。D9、C43 为缓冲回路，C47 用来对 15V 直流电滤波，正常工作后芯片由自激绕组供电。电路的工作过程是输入的直流电压使芯片启动，功率 MOSFET 工作，直流电经功率 MOSFE 进入 S，给电感 L1 充电，稳压管两端的电压经 D6，D8 反馈至 FB，当稳压管两端电压大于 0.23V 时就会触发过流比较器，关断功率 MOSFET。然后 VIPER12A 就会被再启动再关断，如此就把整流后的直流电转换成不同脉冲宽度的矩形波，经电感电容滤波后输出稳定的 15V 直流电压。15V 再经过 LM7805 得到 5V 电压，C48 是对 5V 电压进行滤波，并且通过点亮指示灯来显示是否辅助电源工作正常。

[0062] 如图 7 所示为电流采样电路。在 U、V、W 的接地端接高精度小阻值电阻，把电流信号转换成电压信号，然后电压信号经过运算放大器 LM258 后得到放大，送入 CPU 进行处理。通过实验和计算，可以得到各参数如下：R_o 为 10KΩ，R_2 为 100KΩ，R_3 为 20KΩ，则放大倍数为 $(R_2+R_3)/R_3$ = 6。

[0063] 如图 8 所示为电流检测电路。电流的过流检测是在直流母线上串一个很小的功率电阻，把电流信号转换成电压信号送给电压比较器，电压比较器平时输出高电平 FLTA，比较器输出的是低电平，三极管 3904 不会动作。当过流发生时，比较器输出高电平，T/ITRIP 就会得到高电压，会使逆变器驱动芯片停止工作，同时使三极管导通，输出低电平给芯片故障

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引脚信号，CPU 产生过流保护。相电流 I_S 通过电阻 R_1 转换成电压信号，这个电阻精度必须比较高，在这里采用精度为 0.5%，阻值为 0.06Ω 的检测电阻，电容 C_1 选用 0.1uF(104) 对其进行滤波。R_2 和 R_3 通过对 5V 进行分压，提供过流阀值，经过实验分析选用 R_2 为 10KΩ，R_3 为 2KQ，当检测的电压大于 0.18V 时，即电流超过 3A 时认为过流，比较器 LM393 会输出一个低电平，芯片检测到此信号触发故障中断子程序，关闭 PWM 输出，同时 PWM 驱动电路也会关闭。电流不超过 3A 则正常运行。

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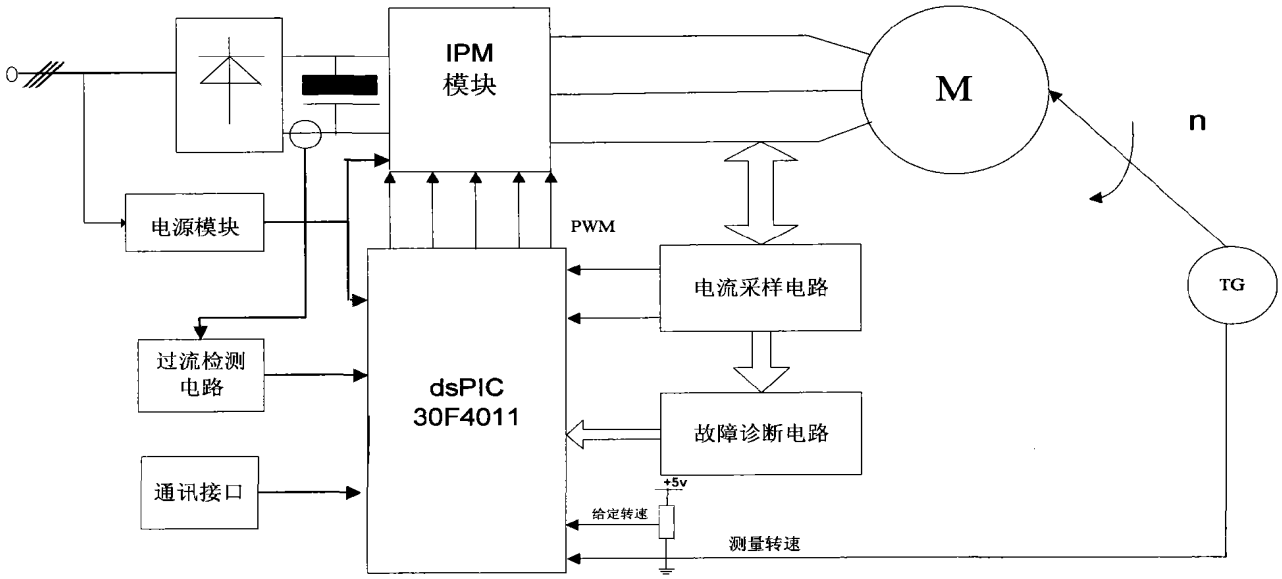


图 1

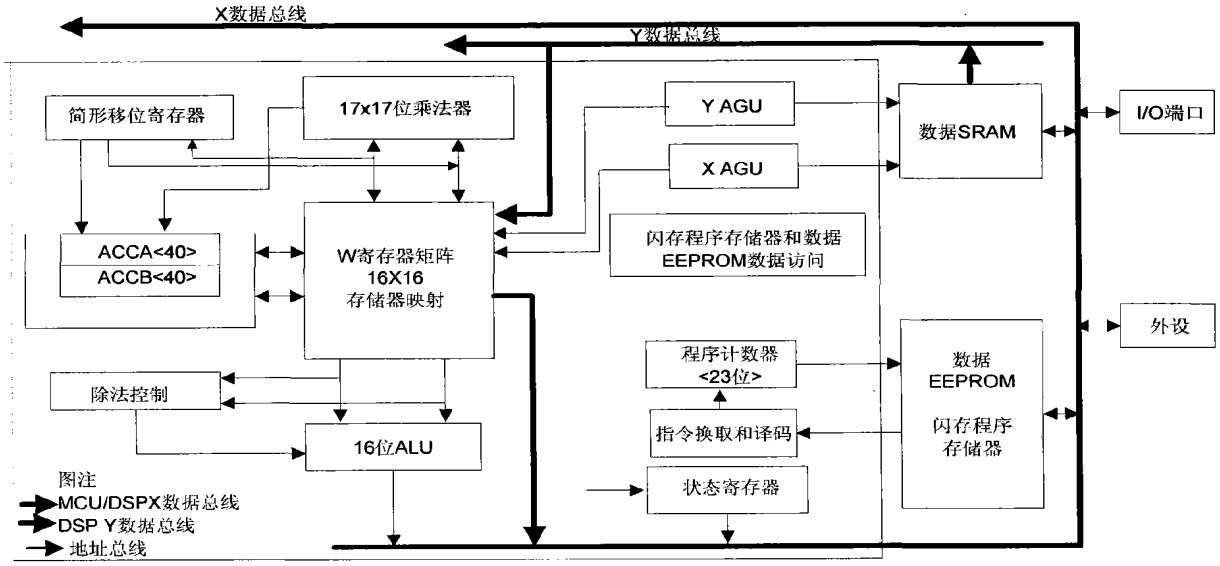


图 2

LIBERTY EXHIBIT 1002, Page 1948

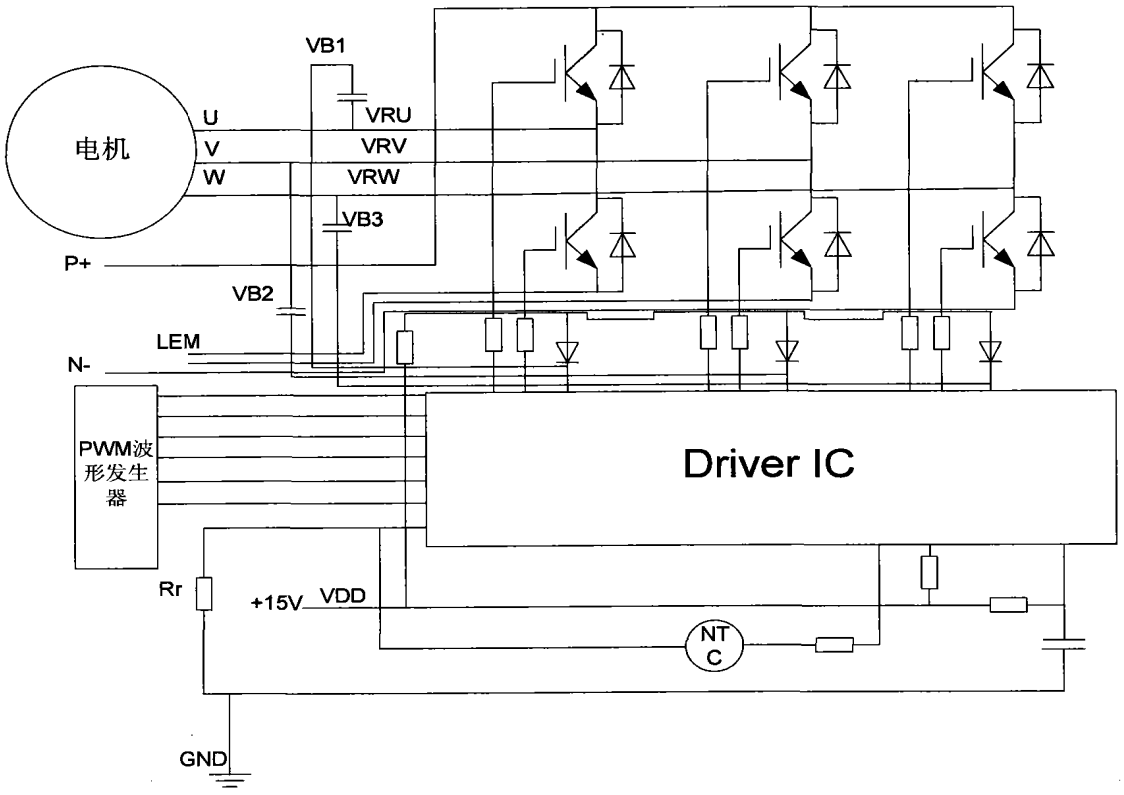


图 3

LIBERTY EXHIBIT 1002, Page 1949

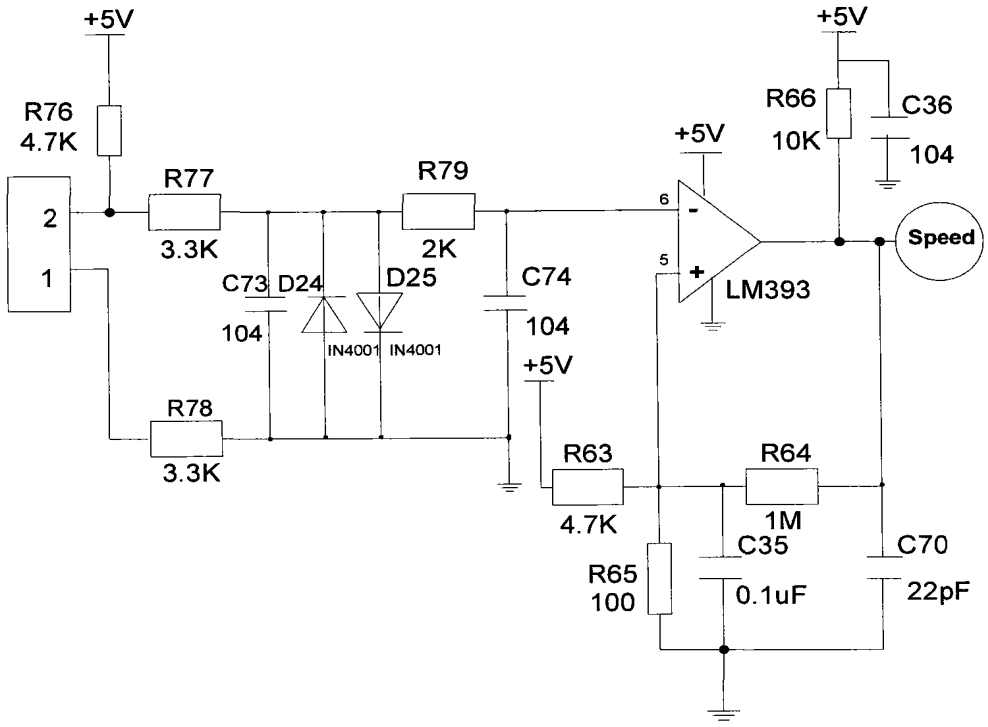


图 4

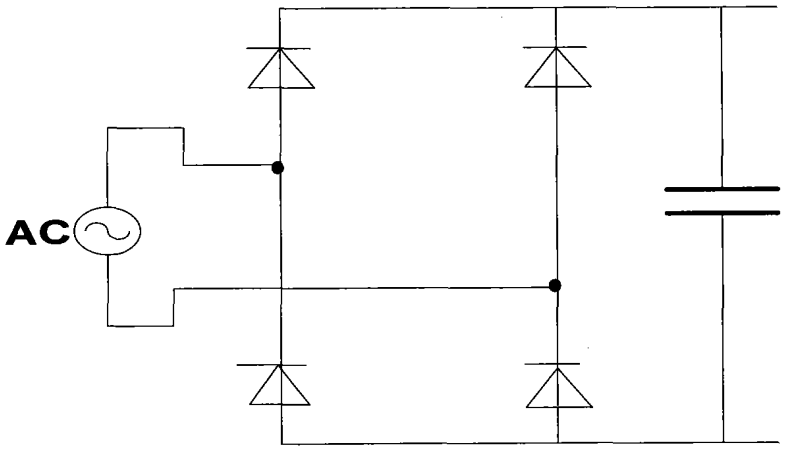


图 5

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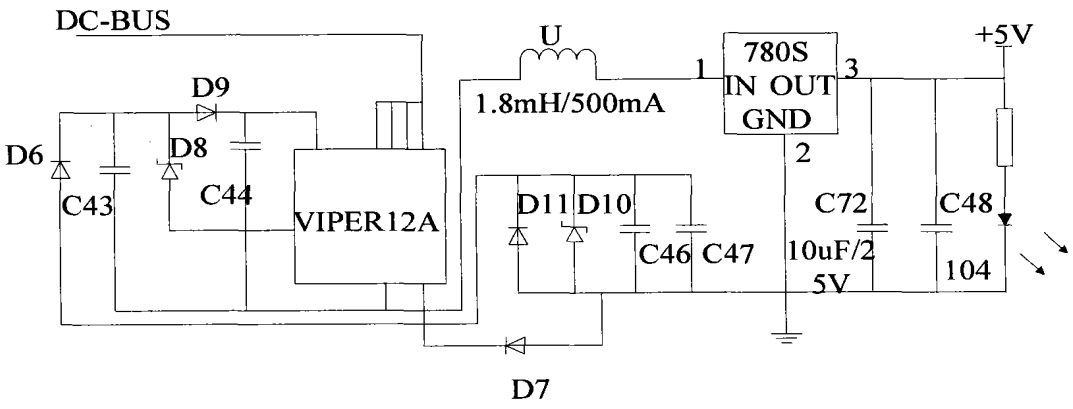


图 6

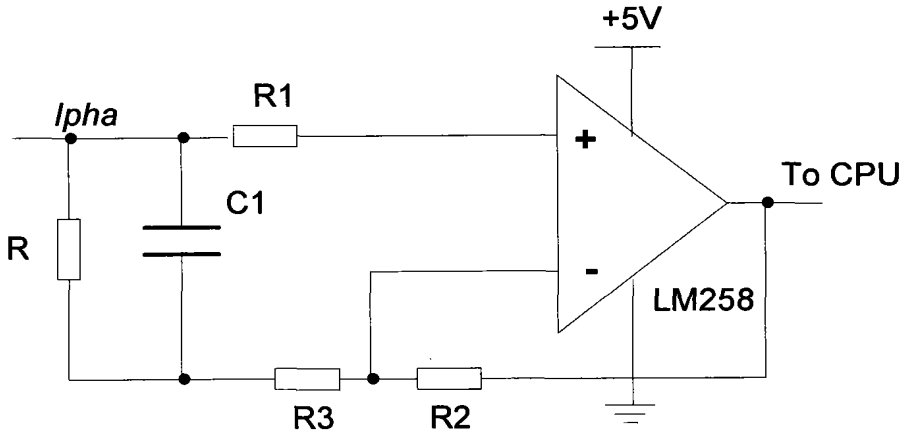


图 7

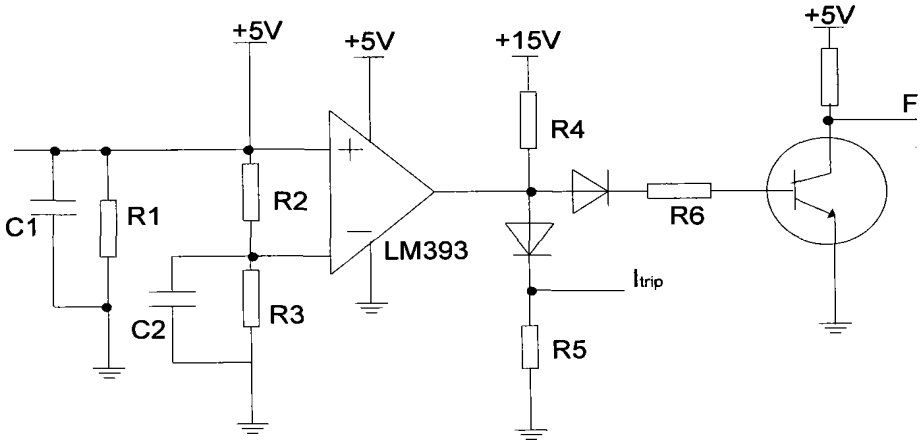


图 8

LIBERTY EXHIBIT 1002, Page 1951

CN102602322A

Electrically-driven fracturing pump truck

Publication Number: CN102602322A

Application Number: CN2012100725967A

Priority Date: March 19, 2012

Filing Date: March 19, 2012

Publication Date: July 25, 2012

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Assignees: N/A

Legal Status: N/A

Abstract

The invention discloses an electrically-driven fracturing pump truck, which comprises a truck chassis with a cab. A lubricating and cooling system, a fracturing pump, a suction manifold, an exhaust manifold, an electrically-driven system and a control system, the suction manifold and the exhaust manifold are connected with the fracturing pump, the electrically-driven system comprises a motor and a motor-driven device, the motor is used for driving the fracturing pump to run, the control system comprises a main power control system and an auxiliary power control system, the main power control system is used for controlling the motor-driven device, the auxiliary power control system is used for controlling the lubricating and cooling system, and the motor-driven device, the main power control system and the auxiliary power control system are powered by an external power source. The electrically-driven fracturing pump truck is simple in structure, reasonable in design, convenient in matching, low in manufacture cost, high in work efficiency and reliability, convenient in energy supply, fine in emission reducing effect, easy in maintenance, capable of overcoming defects and shortcomings of high fuel consumption, difficulty in matching of an engine and a torque converter and the like of a fracturing pump truck in the prior art, and convenient in popularization and use.

Claims

1. An electrically driven pump fracturing, truck chassis comprising (I) with a cab (1-1), attached to the truck chassis lubrication cooling system (8) and fracturing pumps (5) (I), , and an intake manifold (6-1) and a discharge manifold (6-2) is connected to the fracturing pump (5), characterized in that: said truck chassis (I), also equipped with an electric drive system and control system , the electric drive system includes an electric motor (4) and the motor drive means (3) to (5) driving of fracturing pump, the control system comprises an active force control system for controlling the motor driving means (3) (14) and means for controlling the lubrication cooling system (3) auxiliary power control system (15), said motor drive means (3), the active power control system (14) and the auxiliary power control system (15) are powered by an external power source.

2. 2. The electric drive fracturing pump as claimed in claim I in claim 1, characterized in that: said motor (4) for one of the electric motor (4) by a first coupler (9-1) and the fracturing pump (5) is connected.

3. 3. The electric drive as claimed in claim I said fracturing pump, wherein: the electric motor (4) and each of the two first motors (4-1) and the second motor (4-2), said motor drive means (3) and the second of the two motors are a first motor drive means (3-1) and a second motor (4-2) connected to a first electric motor (4-1) connected drive means (3-2), the electric drive system further comprises a gearbox (10), said first motor (4-1) connected to the second coupler (9-2) and the transmission (10), the second motor (4-2) is connected via a third coupler (9-3) and the transmission (10), said gearbox (10) by a fourth joint (9-4) with the fracturing the pump (5) is connected.

4. 4. The electric drive as claimed in claim fracturing pump 2 or 3, wherein: said external power source comprises a wellsite grid (16), a main transformer (11) connected to the wellsite grid (16) and with the main transformer auxiliary transformer (11) connected to (7), said auxiliary transformer (7) mounted on the truck chassis (the I), said motor drive means (3) connected to said main transformer (11) , the active power control system (14) and the auxiliary power control system (15) are connected to the auxiliary transformer (7).

5. 5. The electric drive as claimed in claim fracturing pump 2 or 3, wherein: said external power source comprises an auxiliary transformer (7) generator (12) and the generator (12) is connected, the said auxiliary transformer (7) mounted on the truck chassis (the I), said motor drive means (3) and the generator (12) connected to the main power control system (14) and the auxiliary power control system (15) are connected with the auxiliary transformer (7) is connected.

6. 6. The electric drive as claimed in claim fracturing pump 5, characterized in that: said number generator (12) is one or more, said plurality of generators (12) parallel to each other.

7. 7. The electric drive as claimed in claim fracturing pump 2 or 3, wherein: said active power control system (14) includes a controller (14-1) and a controller (14-1) in contact interactive device (14-2), said motor drive means (3) in contact with said controller (14-1).

8. 8. The electric drive as claimed in claim 7 of the fracturing pump, wherein: said active power control system (14) mounted in the main cabinet control (13-1), the auxiliary power control system (15) mounted in the auxiliary control cabinet (13-2), said motor drive means (3), the main control cabinet (13-1) and the auxiliary control cabinet (13-2) are set in the (2) electric control room, the said electric control room (2) mounted on the truck chassis (I).

9. 9. The electric drive as claimed in claim fracturing pump 2 or 3, wherein: the electric motor (4) is an AC motor or DC motor, said motor drive means (3) for the electric motor (4) supporting the AC motor drive means or dc motor drive apparatus.

10. 10. The electrical drive according to claim 9, fracturing pump, wherein: said drive means to drive the AC motor, said DC motor driving device is a thyristor.

Description

Description

Translated from Chinese

BACKGROUND electrically driven pump fracturing

[0001] The present invention belongs to the technical field of oil exploration, oil-Open relates to a mechanical working device, particularly to an electrically driven pump fracturing.

Background technique

[0002] Fracturing is an important technique in producing oil and gas fields by the reservoir, it needs a high pressure fluid formation fracture pressure to open first, and then further frac sand filled fractures, enhanced formation permeability, improved oil and gas production.

In fracturing, the fracturing equipment performance is good or bad decision to implement fracturing technology to improve.

Well fracturing fracturing equipment is essential technical support.

The total amount of oil and gas fracturing operations, China's annual rate of 10% ~ 20% growth, with the development of deep and difficult wells, fracturing scale increases.

The country has a fracturing fracturing equipment can not meet the growing demand.

[0003] is a high-tech power units fracturing oil equipment, European and American countries, especially the United States more than 80 years of development, production and application of history in this area.

For a long period, China's acquisition of advanced ways of fracturing equipment is imported.

Fracturing fracturing equipment, especially high-power equipment became a "strangle hold" our equipment in the field of oil and gas production.

[0004] Fracturing is a pump pumping equipment mounted on a self-propelled truck chassis, used to perform high pressure, special operations equipment fracturing stimulation job large displacement.

The apparatus consists of two parts, a chassis and upload devices.

The main chassis to move the vehicle provides transport functions, in addition to providing power to upload part (carts) auxiliary systems; upload part fracturing pump working portion is mainly from the power system, transmission system, fracturing pump and manifold system components.

Power generated by the power system, the power transmitted to the end of the fracturing pump via a transmission system, fracturing pump drive operates.

[0005] prior art, whether it is imported or domestic vehicles, which are used in fracturing pump "Diesel - hydraulic torque converter - transmission shaft - fracturing pump" power transmission program.

This arrangement is a scheme based on the power of the engine as a prime mover.

The main problems are: 1, when the fracturing pump truck stand-alone power of 1500kw above, the engine rapidly rising costs, difficulty selection; 2, due to the large size of high-power diesel engine and gearbox weight is not conducive to the design scheme of car and the development of more powerful pump, a diesel engine driving scheme become the bottleneck of the development of new fracturing pump; 3 narrow, component selection and the like supporting the torque converter range, high price; critical elements (engine, torque converter, change twisting, etc.) are to be imported, not only cause costly machine, but also hindered the development of proprietary equipment; 4, fracturing truck grouped in the field of high-power operation, fuel consumption, high cost of oil supply, pushing l overall operating costs; 5, diesel engine

output power when running non-economic range, fuel consumption, adaptability to different operating conditions of the poor.

6, high-power diesel engine noise, high emission and poor working conditions of workers.

SUMMARY

[0006] The present invention solves the technical problem that the prior art in view of the above deficiencies, to provide an electrically driven pump fracturing, its structure is simple, reasonable and novel design, facilitate matching, low cost, high level of automation, working high efficiency, easy supply of energy, good energy saving effect, easy maintenance, high reliability, easy to promote the use of.

[0007] To solve the above technical problem, the technical solution adopted by the invention is: an electrically driven pump fracturing, including a truck chassis with a cab, a cooling system is attached to the lubrication pump and fracturing of the truck chassis, and a suction manifold and a discharge manifold connected to the fracturing pump, wherein: said truck chassis is also equipped with an electric drive system and a control system, the electric

3 and a motor drive system includes a motor drive means for driving the fracturing operation of the pump, the control system comprising a control system for actively controlling the force motor driving means and a control system for controlling a power assist for lubrication and cooling system, the electric motor driving means active force control system and auxiliary power systems are controlled by an external power supply.

[0008] The electrically driven pump fracturing, characterized in that: the motor is a one, the first electric motor through a coupling connected to the fracturing pump.

[0009] The electrically driven pump fracturing, characterized in that: said motor is a two, respectively, and first and second motors, said motor drive means is two and respectively connected to the first electric motor first motor drive means and the second motor drive means connected to the second electric motor, the electric drive system further comprises a gearbox, the first motor is connected through a second clutch and transmission, by the second electric motor coupling a third connector to the gearbox, said gearbox and via a fourth coupling fracturing pump.

[0010] The electrically driven pump fracturing, wherein: said external power source comprises an auxiliary power transformer wellsite, a main transformer connected to the wellsite and the grid is connected with the main transformer, the secondary of the transformer is mounted the truck chassis, said motor drive means connected to the main transformer, the active power control system and auxiliary power to the control systems are connected to an auxiliary transformer.

[0011] The electrically driven pump fracturing, wherein: said external power source comprises a generator and an auxiliary transformer connected to the generator set, the auxiliary transformer is mounted on the truck chassis, the motor drive means connected to the generator set, the active power control system and auxiliary power to the control systems are connected to an auxiliary transformer.

[0012] The electrically driven pump fracturing, characterized in that: said number generator is one or more, the plurality of generators connected in parallel with each other.

[0013] The electrically driven pump fracturing, characterized in that: said active power control system includes a controller and a human interface device in contact with the controller, the motor driving device in contact with the controller.

[0014] The electrically driven pump fracturing, characterized in that: said active power control system installed in the main cabinet control, the control system is installed in the auxiliary power assist control cabinet, said motor drive means, the main control auxiliary control cabinets and cabinets are disposed electrical control room, the electric control room mounted on the truck chassis.

[0015] The electrically driven pump fracturing, characterized in that: said motor is a DC motor or an AC motor, the motor driving apparatus is the motor driving apparatus supporting AC motor or DC motor driving device.

[0016] The electrically driven pump fracturing, characterized in that: said AC motor drive to the drive means, the drive means is a DC motor SCR.

[0017] The present invention and the prior art has the following advantages:

[0018] I, the present invention has a simple structure, reasonable and novel design.

[0019] 2. Supporting facilitate: the present invention and corresponding drive motors, both at home and abroad thyristor mature product, to facilitate selection of matching.

[0020] 3, low cost: the present invention in an electric motor as prime mover fracturing pump, can pump fracturing driving power of the motor to choose the number of medium-power low cost motor, when the motor driving apparatus drives a motor , the overall cost is lower than the engine program.

[0021] 4, a high level of automation, improves the work efficiency: in the motor drive means, the motor can maintain optimum energy efficiency at different power output, the working lowest energy consumption, good energy saving effect, and can achieve a variety of ways to match the output torque, speed, automation and easy to improve the efficiency of the fracturing operation.

[0022] 5, to facilitate the supply of energy: electric drive mode using the present invention, power supply can directly use the well site, eliminating the need for oil transport.

[0023] 6. Easy maintenance: The present invention employs a motor driven pump fracturing operation, as compared with high-power diesel engines, the maintenance of the electrical driving scheme is simple, less control targets, greatly reducing the routine maintenance work and costs.

[0024] 7, high reliability: the reliability of the system is much higher than diesel motors, AC motors can achieve 20 years of maintenance-free motor drive device either using inverter or thyristor, can maintain long-term continuous operation in the case of a plurality of diesel powered generator sets, multiple units in parallel higher reliability than the reliability of a single high-power diesel engines, wherein one unit fail, the reduced power can continue to run without affecting the fracturing operations .

[0025] 8, the present invention is the use of effective, easy to promote use.

[0026] In summary, the invention has simple structure, novel design reasonable, convenient facilities, low cost, high level of automation, high efficiency, convenient energy supply, good energy saving effect, easy maintenance, high reliability, It solves the prior art fracturing pump truck drivetrain prevailing fuel consumption, engine and torque converter difficulty supporting large low power consumption unit is running, poor working conditions and lack of defects, easy to promote the use of.

[0027] The following drawings and embodiments, detailed description of the further aspect of the present invention.

BRIEF DESCRIPTION schematic structural diagram of Embodiment I [0028] I of the present invention FIG.

[0029] FIG 2 structural diagram of embodiment 2 of the present invention.

[0030] FIG. 3 is a plan view of FIG.

[0031] FIG. 4 is a schematic of the power supply connection relationship Example I embodiment of the present invention.

[0032] FIG 5 Example 2 Relationship between the power supply connection schematic embodiment of the present invention.

[0033] REFERENCE NUMERALS: [0034] I- truck chassis; 1-1- cab; 2- electric control room; [0035] 3- motor driving means; a first motor driving means 3-1-; [0036] 3-2- second motor drive means; 4- motor; [0037] 4-1- first motor; 4-2- second motor; 5- fracturing pump; [0038] 6-1- intake manifold ; 6-2- discharge manifold; 7- auxiliary transformer; [0039] 8- lubrication cooling system; 9-1- a first coupling; 9_2_ a second coupling; [0040] The second coupling 9_3_ ; a fourth coupling 9_4_; 10- gearbox; [0041] 11- main transformer; 12- generators; 12-1- a first generator; [0042] 12-1- second generators; 13 -1- main control cabinet; 13-2- auxiliary control cabinet; [0043] 14_ Wang power control system; 14-1- controller; 14-2- interactive apparatus; [0044] 15 auxiliary power control system ; 16- well site grid.

DETAILED DESCRIPTION [0045] Example I [0046] As shown in FIG I, the present invention includes a truck chassis cab 1-1 1, mounted on the truck chassis with a I Run

The cooling system 8 and the sliding fracturing pump 5, and an intake manifold connected to the fracturing pump 5 6-1 and 6-2 exhaust manifold, on the truck chassis I are also equipped with an electric drive system and a control system, the the electric drive system comprises a fracturing pump for driving the motors 4 and 5 the operation of the motor driving device 3, the control system 14 for controlling the lubricating power and the auxiliary cooling system 8 of the main power device 3 comprises a control system for controlling a motor drive the control system 15, the motor driving device 3, the active power control system 14 and control system 15 are auxiliary power by an external power supply.

[0047] In this embodiment, the electric motor 4 is one, the electric motor 4 is connected to the fracturing pump 5 via a first coupling 9-1.

When the fracturing pump 5 require less input power (e.g., less than 900kw), you can use a single high-power electric motor 4 is directly driven fracturing pump 5.

[0048] In this embodiment, the external power supply 16 comprises a wellsite, a main transformer connected to the wellsite grid 11 and the auxiliary transformer 16 and the transformer 11 is connected to the main 7, 7 mounted on the said auxiliary transformer on a truck chassis I, 3 of the main transformer 11 is connected to the motor drive means, said active power control system, power control system 14 and the auxiliary 15 are connected to the auxiliary transformer 7; this embodiment is the vehicle power supply and cost the lowest operating costs of the program.

Specifically, as shown, the primary side coil 4 of the main transformer 11 is connected in series through a cable, and the cable and the vacuum circuit breaker vacuum interrupter Zl and Z2 wellsite grid 16, the vacuum circuit breaker and the well Zl field connection between the power cable 16 TAl current transformers, surge arresters and a charging indicator LI Fl, Al is connected to the meter current transformer TAl, between the vacuum circuit breakers and vacuum circuit breakers Zl and Z2 of cable is

connected between the lightning arrester and connected with a fuse FU F2 and TV voltage transformer in series, the voltage V voltmeter connected transformer on a TV, the main vacuum circuit breaker Z2 transformer primary side coil 11 the current transformer is connected on the cable TA2, arrester F3, K and grounding switch electric lights L2, is connected to said current transformer has TA2 ammeter A2; primary side coil of the auxiliary transformer 7 through the circuit breaker and the circuit breaker QFl QF2 with the main transformer secondary coil 11 is connected.

[0049] In this embodiment, the active power control system 14 includes a controller 14-1 and the controller 14-1 in contact with the human interface device 14-2, the drive motor 3 and the controller means 14-1 phase.

In particular, the active control system 14 further includes a force into the circuit breaker, the voltage detection circuit, a current detection circuit, etc., are conventional in the prior art circuit; said motor drive means into the power supply terminal 3 via the line circuit QF3 QFl breaker device and the main transformer 11 is connected to the secondary coil; the power controller 14-1 and the terminal 14-2 are human interface devices connected to the secondary side coil of the auxiliary transformer 7; the auxiliary power control system of the auxiliary power line side of the secondary side coil 15 of the transformer 7 is connected.

Parameters provided by the interactive apparatus 14-2 comprises a motor drive means 3 is stopped to start, start lubricating cooling system 8 is stopped, the motor 4 is stopped to start, speed and fracturing pressure of the pump motor 4 is 5, the computer interaction 14-2 shows the parameters of the device comprising: a motor driving device 3 of the operating state (including start-stop state and the rotation speed), the pump output pressure fracturing and displacement output 5, 5 fracturing pump oil pressure and temperature, as well as the circuit current and voltage, the above parameters are displayed and transmitted to the controller 14-1 obtained by conventional detection means for detecting the prior art, then the controller 14-1 controls interactive display device 14-2.

The auxiliary power system 15 control the main control loop for the lubrication and cooling system 8, including circuit breakers, contactors, thermal relays control relays and other components, are used in a conventional prior art circuit.

[0050] In this embodiment, the active power control system 14 installed in the main control cabinet 13-1, the auxiliary power control system 15 is mounted in the auxiliary control cabinet 13-2, the motor driving device 3, the main auxiliary control cabinet and control cabinet 13-1 13-2 are arranged in the electric control room 2, the electric control room 2 is mounted on the truck chassis I.

In particular, the electric control room walls 2 can be welded together by a steel plate, in order to make electrical insulation function having a control room 2, to ensure proper operating at a suitable temperature in the electric control room 2, through the electrically control room wall 2 is provided two-layer structure and be implemented within the electric control room filled with a refractory wall 2; in addition, may also be mounted on the movable door in the wall of electric control room 2, the electrical control room 2 the seat 2-1 is provided, personnel access and easy operation of the electronic control device installed in the control room.

[0051] In this embodiment, the electric motor 4 is a DC motor or an AC motor, said motor drive means 3 and 4 supporting the AC motor or DC motor driving apparatus a motor driving apparatus.

In particular, the AC motor drive to the drive means, the drive means is a DC motor thyristor, i.e., when the AC motor 4 is an electric motor drive device 3 using frequency converter, when the motor 4 using the DC

motor, the motor drive device 3 is realized using silicon, two drive scheme has a significant energy saving and emission reduction.

[0052] Example 2

[0053] As shown in FIGS. 2 and 3, the present embodiment and the embodiment I except that: the two motors 4, respectively, and the first motor and the second motor 4-1 4-2, the electric motor two drive means 3 and the second motor are connected to a first motor driving the first motor means 4-1 and 3-1 and 4-2 connected to the second motor drive apparatus 32, the electric drive system, 10 further includes a first electric motor through a gearbox connected to a second 4-1 and 9-2 clutch transmission 10, the second motor 4-2 through 9-3 and the third transmission clutch 10 connected to a gearbox 10 connected to the fracturing pump 5 via a fourth coupling 9-4.

The external power supply includes an auxiliary transformer 12 and a generator 12 connected to the generator set 7, the auxiliary transformer 7 is mounted on the truck chassis I, the generator 3 is connected with the motor driving device 12, the said control system 14 main power and auxiliary power to the control system 15 are auxiliary transformer 7 is connected.

In particular, the generator 12 of the number of groups is one or more, 12 parallel to each other of the plurality of generators.

The remaining structures are the same as in Example I.

[0054] In particular, the generator 12 is a diesel or gas turbine generator sets.

In this embodiment, the two generators 12 and 12-1 respectively, the first and second generators 12 generators.

5, the first and second generators generators 12-1 12-2 parallel with each other, the primary coil of the auxiliary transformer 7 through the circuit breaker and the circuit breaker QF8 QF4 first generator 12-1 an output terminal connected to an output terminal and is connected by a circuit breaker and a circuit breaker QF8 QF5 second generator 12-2, a first motor drive device 3-1 through the power supply terminal and a breaker breaker QF6 feed line and the first power QF4 unit 12-1 connected to an output terminal through the output terminal and connected into the circuit breaker and the circuit breaker QF5 QF6 second generator 12-2, a second power supply terminal via the motor drive apparatus 32 into the circuit breaker and QF7 and a first circuit breaker QF4 generator output terminal 12-1 is connected via the output terminal and connected into the circuit breaker and the circuit breaker QF5 QF7 second generators 12-2; 14-1 and the interactive controller supply terminal apparatus 14-2 are connected to the secondary side coil of the auxiliary transformer 7; the auxiliary power control system power supply line side and the secondary side coil of the transformer 7 is connected to the secondary 15.

When [0055] When Li fracturing and 5 require a large input power of a single motor is insufficient to drive a fracturing Li 4 5, 4 by two electric motors commonly driven through a gearbox 10 5 fracturing pump.

When the driving more powerful fracturing pump 5, a plurality of motors may also be employed by 4 in series or in parallel to the transfer case driven fracturing pump 5.

Power generator 12 are connected in parallel [0056] The use of multiple lower power, more advantages compared with a single power supply generator 12, cost, and reliability.

Using a generator to power grid can be arbitrarily selected number generator 12 according to power requirements, help save fuel.

[0057] In the present invention, the active power control system 14 is responsible for controlling the entire electrically driven pump fracturing job, interactive device 14-2 through the input control parameters, but also electrically through interactive display device 14-2 driving the real-time status fracturing pump, and improve the control precision degree of information throughout the fracturing pump.

Adjusting the output 14-1 via the motor driving device 3 in the main power control system controller 14 may be implemented stepless speed motor 4, 5 meet the operational needs of the fracturing pump can be driven at different pressures fracturing pump output 5 and high pressure liquid flow, easy to implement more and more complex control functions.

[0058] In the present invention, the electric drive system, and the lubrication and cooling system 8 may also have a control system powered by a battery.

The main control cabinet 13-1 through 13-3 and the auxiliary control cabinet is bolted to the electrical control room 2 the floor or wall to accommodate long-distance transport.

2 electric control room with sound insulation, waterproofing, insulation and other functions, operator time for the control operation.

[0059] In summary, the present invention is directed to the existing truck powertrain fracturing present fuel consumption, the engine and the torque converter matching difficulties, high fuel consumption and low-power operation unit, defects and poor working conditions, proposed 4 electric motor as the prime mover of fracturing truck program, simple structure, novel and reasonable design, convenient facilities, low cost, high level of automation, high efficiency, energy supply, convenient, easy maintenance, high reliability, the use of effective easy to promote the use.

[0060] The above are only preferred embodiments of the present invention, not any limitation of the present invention, any simple modification according to any of the technical spirit of the present invention made of the foregoing embodiments, changes and equivalents structural changes, fall within the scope of the technical solution of the present invention.

(19)中华人民共和国国家知识产权局

(12)发明专利申请

(10)申请公布号 CN 102602322 A
(43)申请公布日 2012.07.25

(21)申请号 201210072596.7

(22)申请日 2012.03.19

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(51)Int.Cl.
B60P 3/14(2006.01)

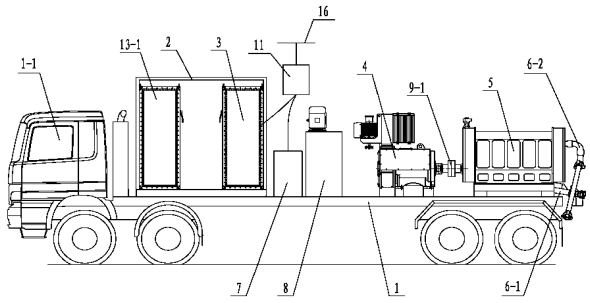
权利要求书 1 页 说明书 6 页 附图 5 页

(54)发明名称

电驱动压裂泵车

(57)摘要

本发明公开了一种电驱动压裂泵车，包括带驾驶室的卡车底盘，卡车底盘上安装有润滑冷却系统和压裂泵，以及与压裂泵连接的吸入管汇和排出管汇，卡车底盘上还安装有电驱动系统和控制系统，电驱动系统包括用于驱动压裂泵运转的电动机和电动机驱动装置，控制系统包括用于控制电动机驱动装置的主动力控制系统以及用于控制润滑冷却系统的辅助动力控制系统，电动机驱动装置、主动力控制系统和辅助动力控制系统均通过外部电源供电。本发明结构简单，设计合理，配套方便，造价低，工作效率高、可靠性高，能源供应方便，节能减排效果好，易于维护，解决了现有技术中压裂泵车存在的燃油消耗大、发动机和变矩器配套困难等缺陷和不足，便于推广使用。



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1. 一种电驱动压裂泵车，包括带驾驶室（1-1）的卡车底盘（1），所述卡车底盘（1）上安装有润滑冷却系统（8）和压裂泵（5），以及与压裂泵（5）连接的吸入管汇（6-1）和排出管汇（6-2），其特征在于：所述卡车底盘（1）上还安装有电驱动系统和控制系统，所述电驱动系统包括用于驱动压裂泵（5）运转的电动机（4）和电动机驱动装置（3），所述控制系统包括用于控制电动机驱动装置（3）的主动力控制系统（14）以及用于控制润滑冷却系统（8）的辅助动力控制系统（15），所述电动机驱动装置（3）、主动力控制系统（14）和辅助动力控制系统（15）均通过外部电源供电。

2. 按照权利要求 1 所述的电驱动压裂泵车，其特征在于：所述电动机（4）为一台，所述电动机（4）通过第一联轴器（9-1）与所述压裂泵（5）连接。

3. 按照权利要求 1 所述的电驱动压裂泵车，其特征在于：所述电动机（4）为两台且分别为第一电动机（4-1）和第二电动机（4-2），所述电动机驱动装置（3）为两台且分别为与第一电动机（4-1）连接的第一电动机驱动装置（3-1）和与第二电动机（4-2）连接的第二电动机驱动装置（3-2），所述电驱动系统还包括变速箱（10），所述第一电动机（4-1）通过第二联轴器（9-2）与变速箱（10）连接，所述第二电动机（4-2）通过第三联轴器（9-3）与变速箱（10）连接，所述变速箱（10）通过第四联轴器（9-4）与压裂泵（5）连接。

4. 按照权利要求 2 或 3 所述的电驱动压裂泵车，其特征在于：所述外部电源包括井场电网（16）、与井场电网（16）连接的主变压器（11）和与所述主变压器（11）连接的辅助变压器（7），所述辅助变压器（7）安装在所述卡车底盘（1）上，所述电动机驱动装置（3）与所述主变压器（11）连接，所述主动力控制系统（14）和辅助动力控制系统（15）均与所述辅助变压器（7）连接。

5. 按照权利要求 2 或 3 所述的电驱动压裂泵车，其特征在于：所述外部电源包括发电机组（12）和与所述发电机组（12）连接的辅助变压器（7），所述辅助变压器（7）安装在所述卡车底盘（1）上，所述电动机驱动装置（3）与所述发电机组（12）连接，所述主动力控制系统（14）和辅助动力控制系统（15）均与所述辅助变压器（7）连接。

6. 按照权利要求 5 所述的电驱动压裂泵车，其特征在于：所述发电机组（12）的数量为一台或多台，多台所述发电机组（12）相互并联。

7. 按照权利要求 2 或 3 所述的电驱动压裂泵车，其特征在于：所述主动力控制系统（14）包括控制器（14-1）和与控制器（14-1）相接的人机交互设备（14-2），所述电动机驱动装置（3）与所述控制器（14-1）相接。

8. 按照权利要求 7 所述的电驱动压裂泵车，其特征在于：所述主动力控制系统（14）安装在主控制柜（13-1）内，所述辅助动力控制系统（15）安装在辅助控制柜（13-2）内，所述电动机驱动装置（3）、主控制柜（13-1）和辅助控制柜（13-2）均设置在电控房（2）内，所述电控房（2）安装在所述卡车底盘（1）上。

9. 按照权利要求 2 或 3 所述的电驱动压裂泵车，其特征在于：所述电动机（4）为交流电动机或直流电动机，所述电动机驱动装置（3）为与电动机（4）配套的交流电动机驱动装置或直流电动机驱动装置。

10. 按照权利要求 9 所述的电驱动压裂泵车，其特征在于：所述交流电动机驱动装置为变频器，所述直流电动机驱动装置为可控硅。

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电驱动压裂泵车

技术领域

[0001] 本发明属于石油开采技术领域，涉及一种石油开采用机械作业设备，尤其是涉及一种电驱动压裂泵车。

背景技术

[0002] 压裂是油气田增储上产的重要技术手段，需要借助高压流体先将地层裂缝压开，再往裂缝中充填压裂砂，增强地层渗透率，提高油气产量。在压裂施工中，压裂设备性能好坏决定压裂技术提高的实现。精良的压裂装备是压裂施工必备的技术支撑。我国油气田压裂施工作业总量每年以 10％～ 20％的速度增长，随着深井和难井的开发，压裂施工规模逐渐增大。国内拥有的压裂设备远不能满足压裂施工增长需求。

[0003] 大功率压裂机组是高技术含量石油装备，欧美国家，特别是美国在这一领域已有 80 年的研发生产和应用历史。在相当长的一个时期，我国获取先进压裂装备的途径就是进口。压裂装备特别是大功率压裂装备一度成为我国油气生产领域的“卡脖子”设备。

[0004] 压裂泵车是将泵送设备安装在自走式卡车底盘上，用来执行高压力、大排量的油井压裂增产作业的特种作业装备。该装置由底盘和上装设备两部分组成。底盘主要为整车提供移运功能，此外还为上装部分（车台）的辅助系统提供动力；上装部分是压裂泵车的工作部分，主要由动力系统、传动系统、压裂泵和管汇系统等组成。由动力系统产生的动力，通过传动系统传递到压裂泵动力端，驱动压裂泵进行工作。

[0005] 现有技术中，无论是进口产品，还是国产车辆，其压裂泵车均采用“柴油机－液力变矩器－传动轴－压裂泵”的动力传动方案。这种布置方式是基于发动机为原动机的动力方案。存在的主要问题是：1、当压裂泵车的单机功率达到 1500kW 以上的时候，发动机成本迅速上升，选型困难；2、由于大功率柴油机和变速箱尺寸重量大，不利于车载方案的设计和更大功率泵车的开发，柴油机驱动方案成为制约新型压裂泵车开发的瓶颈；3、配套的变矩器等元件选型范围窄，价格高；重要元件（发动机、变矩器、变扭器等）均需要进口，不仅造成整机成本高昂，还阻碍了具有自主知识产权装备的开发；4、大功率压裂泵车编组在野外运行时，燃油消耗大，油料补给成本高，推升整体作业成本；5、柴油机输出功率在非经济运行区间时，燃油消耗大，对不同作业条件的适应性差。6、大功率柴油机噪音大、排放高，工人作业条件差。

发明内容

[0006] 本发明所要解决的技术问题在于针对上述现有技术中的不足，提供一种电驱动压裂泵车，其结构简单，设计新颖合理，配套方便，造价低，自动控制水平高，工作效率高，能源供应方便，节能减排效果好，易于维护，工作可靠性高，便于推广使用。

[0007] 为解决上述技术问题，本发明采用的技术方案是：一种电驱动压裂泵车，包括带驾驶室的卡车底盘，所述卡车底盘上安装有润滑冷却系统和压裂泵，以及与压裂泵连接的吸入管汇和排出管汇，其特征在于：所述卡车底盘上还安装有电驱动系统和控制系统，所述电

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驱动系统包括用于驱动压裂泵运转的电动机和电动机驱动装置，所述控制系统包括用于控制电动机驱动装置的主动力控制系统以及用于控制润滑冷却系统的辅助动力控制系统，所述电动机驱动装置、主动力控制系统和辅助动力控制系统均通过外部电源供电。

[0008] 上述的电驱动压裂泵车，其特征在于：所述电动机为一台，所述电动机通过第一联轴器与所述压裂泵连接。

[0009] 上述的电驱动压裂泵车，其特征在于：所述电动机为两台且分别为第一电动机和第二电动机，所述电动机驱动装置为两台且分别为与第一电动机连接的第一电动机驱动装置和与第二电动机连接的第二电动机驱动装置，所述电驱动系统还包括变速箱，所述第一电动机通过第二联轴器与变速箱连接，所述第二电动机通过第三联轴器与变速箱连接，所述变速箱通过第四联轴器与压裂泵连接。

[0010] 上述的电驱动压裂泵车，其特征在于：所述外部电源包括井场电网、与井场电网连接的主变压器和与所述主变压器连接的辅助变压器，所述辅助变压器安装在所述卡车底盘上，所述电动机驱动装置与所述主变压器连接，所述主动力控制系统和辅助动力控制系统均与所述辅助变压器连接。

[0011] 上述的电驱动压裂泵车，其特征在于：所述外部电源包括发电机组和与所述发电机组连接的辅助变压器，所述辅助变压器安装在所述卡车底盘上，所述电动机驱动装置与所述发电机组连接，所述主动力控制系统和辅助动力控制系统均与所述辅助变压器连接。

[0012] 上述的电驱动压裂泵车，其特征在于：所述发电机组的数量为一台或多台，多台所述发电机组相互并联。

[0013] 上述的电驱动压裂泵车，其特征在于：所述主动力控制系统包括控制器和与控制器相接的人机交互设备，所述电动机驱动装置与所述控制器相接。

[0014] 上述的电驱动压裂泵车，其特征在于：所述主动力控制系统安装在主控制柜内，所述辅助动力控制系统安装在辅助控制柜内，所述电动机驱动装置、主控制柜和辅助控制柜均设置在电控房内，所述电控房安装在所述卡车底盘上。

[0015] 上述的电驱动压裂泵车，其特征在于：所述电动机为交流电动机或直流电动机，所述电动机驱动装置为与电动机配套的交流电动机驱动装置或直流电动机驱动装置。

[0016] 上述的电驱动压裂泵车，其特征在于：所述交流电动机驱动装置为变频器，所述直流电动机驱动装置为可控硅。

[0017] 本发明与现有技术相比具有以下优点：

[0018] 1、本发明的结构简单，设计新颖合理。

[0019] 2、配套方便：本发明中电动机和相应的变频器、可控硅在国内外均有成熟的产品，选型配套方便。

[0020] 3、造价低：本发明以电动机作为原动机驱动压裂泵，可以根据所驱动的压裂泵的功率，选择电动机的数量，中等功率的电动机造价低，用电动机驱动装置驱动电动机时，整体造价比发动机方案低。

[0021] 4、自动控制水平高，提高了工作效率：在电动机驱动装置驱动下，电动机可在不同功率输出下保持最佳的能源利用率，使作业能源消耗达到最低，节能减排效果好，同时可以实现扭矩、转速的各种匹配输出方式，易于提高压裂作业的自动化水平和效率。

[0022] 5、能源供应方便：本发明采用电力驱动方式，可以直接利用井场电网供电，省去了

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油料运输。

[0023] 6、易于维护：本发明采用电动机驱动压裂泵运转，与大功率柴油机相比，该电驱动方案的维护非常简单，控制指标少，大大减少了日常维护工作量和成本。

[0024] 7、工作可靠性高：电动机系统的可靠性远高于柴油机系统，交流电动机可以实现20年免维护，电动机驱动装置无论是采用变频器还是可控硅，均可保持长期不间断运行，在采用多台柴油机发电机机组供电的情况下，多台机组并联的可靠性高于单台大功率柴油机的可靠性，其中一台机组出现问题，系统可以降功率继续运行，不影响压裂作业。

[0025] 8、本发明的使用效果好，便于推广使用。

[0026] 综上所述，本发明结构简单，设计新颖合理，配套方便，造价低，自动控制水平高，工作效率高，能源供应方便，节能减排效果好，易于维护，工作可靠性高，解决了现有技术中压裂泵车动力传动系统存在的燃油消耗大、发动机和变矩器配套困难、机组低功率运行时油耗大、作业条件差等缺陷和不足，便于推广使用。

[0027] 下面通过附图和实施例，对本发明的技术方案做进一步的详细描述。

附图说明

[0028] 图1为本发明实施例1的结构示意图。

[0029] 图2为本发明实施例2的结构示意图。

[0030] 图3为图2的俯视图。

[0031] 图4为本发明实施例1的供电连接关系示意图。

[0032] 图5为本发明实施例2的供电连接关系示意图。

[0033] 附图标记说明：

[0034] 1-卡车底盘；1-1-驾驶室；2-电控房；

[0035] 3-电动机驱动装置；3-1-第一电动机驱动装置；

[0036] 3-2-第二电动机驱动装置；4-电动机；

[0037] 4-1-第一电动机；4-2-第二电动机；5-压裂泵；

[0038] 6-1-吸入管汇；6-2-排出管汇；7-辅助变压器；

[0039] 8-润滑冷却系统；9-1-第一联轴器；9-2-第二联轴器；

[0040] 9-3-第三联轴器；9-4-第四联轴器；10-变速箱；

[0041] 11-主变压器；12-发电机组；12-1-第一发电机组；

[0042] 12-1-第二发电机组；13-1-主控制柜；13-2-辅助控制柜；

[0043] 14-主动力控制系统；14-1-控制器；14-2-人机交互设备；

[0044] 15-辅助动力控制系统；16-井场电网。

具体实施方式

[0045] 实施例1

[0046] 如图1所示，本发明包括带驾驶室1-1的卡车底盘1，所述卡车底盘1上安装有润滑冷却系统8和压裂泵5，以及与压裂泵5连接的吸入管汇6-1和排出管汇6-2，所述卡车底盘1上还安装有电驱动系统和控制系统，所述电驱动系统包括用于驱动压裂泵5运转的电动机4和电动机驱动装置3，所述控制系统包括用于控制电动机驱动装置3的主动力控制

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系统 14 以及用于控制润滑冷却系统 8 的辅助动力控制系统 15，所述电动机驱动装置 3、主动力控制系统 14 和辅助动力控制系统 15 均通过外部电源供电。

[0047] 本实施例中，所述电动机 4 为一台，所述电动机 4 通过第一联轴器 9-1 与所述压裂泵 5 连接。当压裂泵 5 输入功率需要较小时（例如小于 900kw），就可以用单台大功率电动机 4 直接驱动压裂泵 5。

[0048] 本实施例中，所述外部电源包括井场电网 16、与井场电网 16 连接的主变压器 11 和与所述主变压器 11 连接的辅助变压器 7，所述辅助变压器 7 安装在所述卡车底盘 1 上，所述电动机驱动装置 3 与所述主变压器 11 连接，所述主动力控制系统 14 和辅助动力控制系统 15 均与所述辅助变压器 7 连接；这种供电方案是整车造价和运行成本最低的方案。具体地，如图 4 所示，所述主变压器 11 的一次侧线圈通过电缆以及串联在电缆上的真空断路器 Z1 和真空断路器 Z2 与井场电网 16 连接，所述真空断路器 Z1 与井场电网 16 之间的电缆上连接有电流互感器 TA1、避雷器 F1 和带电指示灯 L1，所述电流互感器 TA1 上连接有电流表 A1，所述真空断路器 Z1 和与真空断路器 Z2 之间的电缆上连接有避雷器 F2 且连接有相串联的熔断器 FU 和电压互感器 TV，所述电压互感器 TV 上连接有电压表 V，所述真空断路器 Z2 与主变压器 11 的一次侧线圈之间的电缆上连接有电流互感器 TA2、避雷器 F3、接地开关 K 和带电指示灯 L2，所述电流互感器 TA2 上连接有电流表 A2；所述辅助变压器 7 的一次侧线圈通过断路器 QF1 和断路器 QF2 与主变压器 11 的二次侧线圈连接。

[0049] 本实施例中，所述主动力控制系统 14 包括控制器 14-1 和与控制器 14-1 相接的人机交互设备 14-2，所述电动机驱动装置 3 与所述控制器 14-1 相接。具体地，所述主动力控制系统 14 还包括进线断路器、电压检测电路、电流检测电路等，均采用现有技术中的常规电路连接；所述电动机驱动装置 3 的电源端通过进线断路器 QF3 和断路器 QF1 与主变压器 11 的二次侧线圈连接；所述控制器 14-1 和人机交互设备 14-2 的电源端均与辅助变压器 7 的二次侧线圈连接；所述辅助动力控制系统 15 的电源进线端与辅助变压器 7 的二次侧线圈连接。通过人机交互设备 14-2 设置的参数包括电动机驱动装置 3 的启动停止、润滑冷却系统 8 的启动停止、电动机 4 的启动停止、电动机 4 的转速和压裂泵 5 的压力，通过人机交互设备 14-2 显示的参数包括：电动机驱动装置 3 的运行状态（包括启停状态和转速）、压裂泵 5 的输出压力和输出排量、压裂泵 5 润滑油压力和温度、以及电路中的电流和电压，以上显示的参数均通过现有技术中的常规检测手段检测得到并传输给控制器 14-1，控制器 14-1 再控制人机交互设备 14-2 进行显示。所述辅助动力控制系统 15 主要为润滑冷却系统 8 的控制回路，包括有断路器、接触器、热继电器以及控制继电器等元器件，均采用现有技术中的常规电路连接。

[0050] 本实施例中，所述主动力控制系统 14 安装在主控制柜 13-1 内，所述辅助动力控制系统 15 安装在辅助控制柜 13-2 内，所述电动机驱动装置 3、主控制柜 13-1 和辅助控制柜 13-2 均设置在电控房 2 内，所述电控房 2 安装在所述卡车底盘 1 上。具体地，所述电控房 2 的墙体可以通过钢板焊接而成，为了使得电控房 2 具有保温功能，以便确保电控房 2 内的设备能在合适的温度下工作，可以通过将电控房 2 的墙体设置为双层结构并在电控房 2 的墙体内填充耐火材料来实现；另外，还可以在电控房 2 的墙体上安装活动门，在电控房 2 内设置座椅 2-1，方便操作人员进出及对安装在电控房内的设备进行控制。

[0051] 本实施例中，所述电动机 4 为交流电动机或直流电动机，所述电动机驱动装置 3 为

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与电动机 4 配套的交流电动机驱动装置或直流电动机驱动装置。具体地，所述交流电动机驱动装置为变频器，所述直流电动机驱动装置为可控硅，即当电动机 4 采用交流电动机时，电动机驱动装置 3 采用变频器实现，当电动机 4 采用直流电动机时，电动机驱动装置 3 采用可控硅实现，两种驱动方案均有显著的节能、减排效果。

[0052] 实施例 2

[0053] 如图 2 和图 3 所示，本实施例与实施例 1 不同的是：所述电动机 4 为两台且分别为第一电动机 4-1 和第二电动机 4-2，所述电动机驱动装置 3 为两台且分别为与第一电动机 4-1 连接的第一电动机驱动装置 3-1 和与第二电动机 4-2 连接的第二电动机驱动装置 3-2，所述电驱动系统还包括变速箱 10，所述第一电动机 4-1 通过第二联轴器 9-2 与变速箱 10 连接，所述第二电动机 4-2 通过第三联轴器 9-3 与变速箱 10 连接，所述变速箱 10 通过第四联轴器 9-4 与压裂泵 5 连接。所述外部电源包括发电机组 12 和与所述发电机组 12 连接的辅助变压器 7，所述辅助变压器 7 安装在所述卡车底盘 1 上，所述电动机驱动装置 3 与所述发电机组 12 连接，所述主动力控制系统 14 和辅助动力控制系统 15 均与所述辅助变压器 7 连接。具体地，所述发电机组 12 的数量为一台或多台，多台所述发电机组 12 相互并联。其余结构均与实施例 1 相同。

[0054] 具体地，所述发电机组 12 为柴油发电机组或燃气发电机组。本实施例中，所述发电机组 12 为两台且分别为第一发电机组 12-1 和第二发电机组 12。如图 5 所示，第一发电机组 12-1 和第二发电机组 12-2 相互并联，所述辅助变压器 7 的一次侧线圈通过断路器 QF4 和断路器 QF8 与第一发电机组 12-1 的输出端连接且通过断路器 QF5 和断路器 QF8 与第二发电机组 12-2 的输出端连接，第一电动机驱动装置 3-1 的电源端通过进线断路器 QF6 和断路器 QF4 与第一发电机组 12-1 的输出端连接且通过进线断路器 QF6 和断路器 QF5 与第二发电机组 12-2 的输出端连接，第二电动机驱动装置 3-2 的电源端通过进线断路器 QF7 和断路器 QF4 与第一发电机组 12-1 的输出端连接且通过进线断路器 QF7 和断路器 QF5 与第二发电机组 12-2 的输出端连接；所述控制器 14-1 和人机交互设备 14-2 的电源端均与辅助变压器 7 的二次侧线圈连接；所述辅助动力控制系统 15 的电源进线端与辅助变压器 7 的二次侧线圈连接。

[0055] 当压裂泵 5 输入功率需要较大且单台电动机 4 不足以驱动压裂泵 5 时，由两台电动机 4 通过变速箱 10 共同驱动压裂泵 5。当驱动更大功率的压裂泵 5 时，还可以采用多台电动机 4 串联或者通过分动箱并联的方式驱动压裂泵 5。

[0056] 使用多台较小功率的发电机组 12 相互并联供电，与单台大功率发电机组 12 供电相比，造价和运行可靠性上更有优势。采用发电机组供电可以根据功率需求任意选择并网发电机组 12 的数量，有助于节省燃油。

[0057] 本发明中，主动力控制系统 14 负责对整个电驱动压裂泵车工作的控制，能够通过人机交互设备 14-2 输入控制参数，还能通过人机交互设备 14-2 显示电驱动压裂泵车的实时状态，提高了整个压裂泵车的控制精度和信息化程度。通过主动力控制系统 14 中的控制器 14-1 调节电动机驱动装置 3 的输出，可以实现电动机 4 的无级连续调速，满足压裂泵 5 的工作需要，能够驱动压裂泵 5 输出不同压力和流量的高压液体，易于实现更多、更复杂的控制功能。

[0058] 另外，本发明中，所述电驱动系统、润滑冷却系统 8 和控制系统还可以均通过电池

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供电。主控制柜 13-1 和辅助控制柜 13-3 通过螺栓固定在电控房 2 内地面或者墙壁上，以适应长途运输。电控房 2 具有隔音、防水、保温等功能，适合操作人员长时间控制作业。

[0059] 综上所述，本发明针对现有压裂泵车动力传动系统存在的燃油消耗大、发动机和变矩器配套困难、机组低功率运行时油耗大、作业条件差等缺点，提出了以电动机 4 作为原动机的压裂泵车方案，结构简单，设计新颖合理，配套方便，造价低，自动控制水平高，工作效率高，能源供应方便，易于维护，工作可靠性高，使用效果好，便于推广使用。

[0060] 以上所述，仅是本发明的较佳实施例，并非对本发明作任何限制，凡是根据本发明技术实质对以上实施例所作的任何简单修改、变更以及等效结构变化，均仍属于本发明技术方案的保护范围内。

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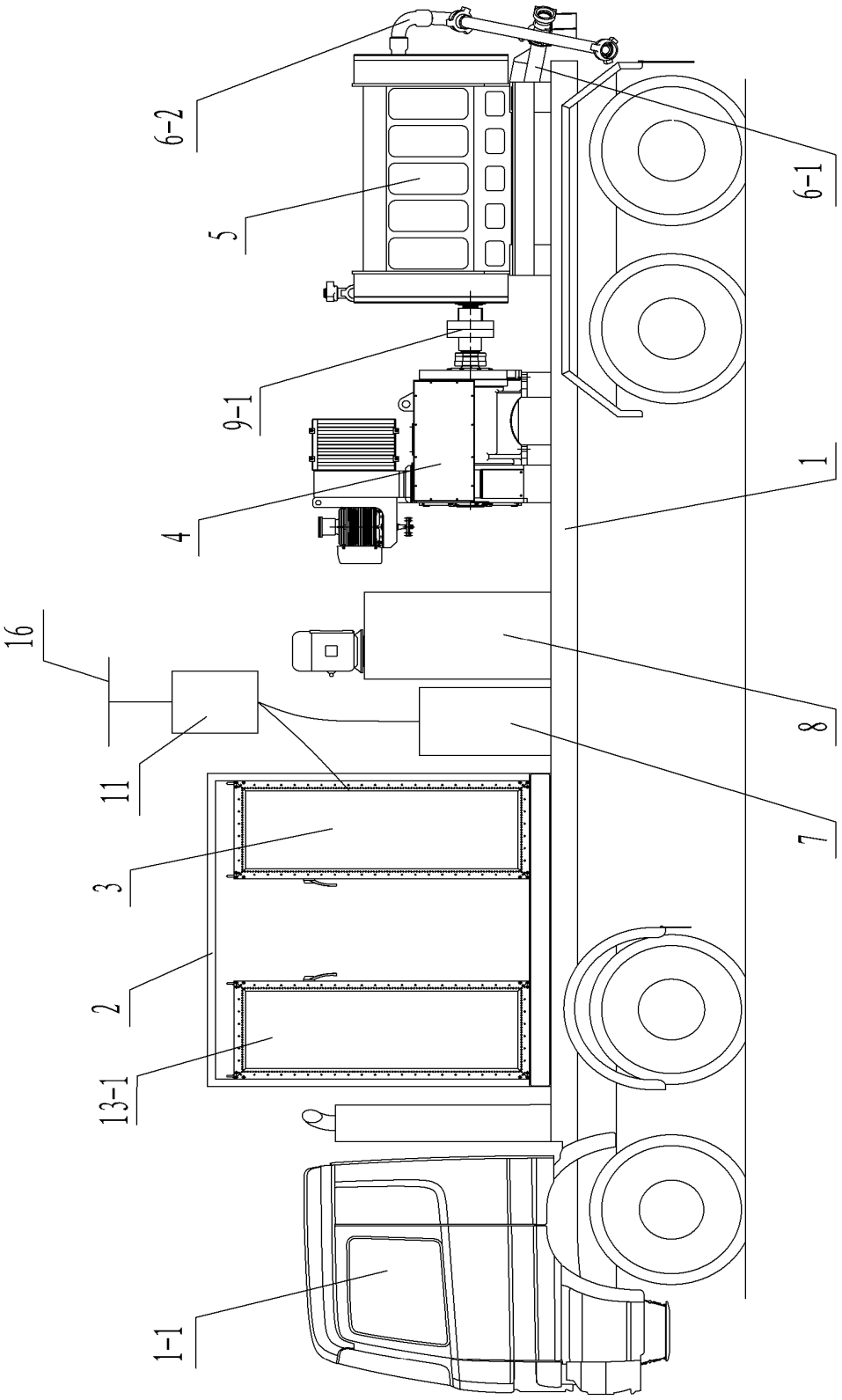


图 1

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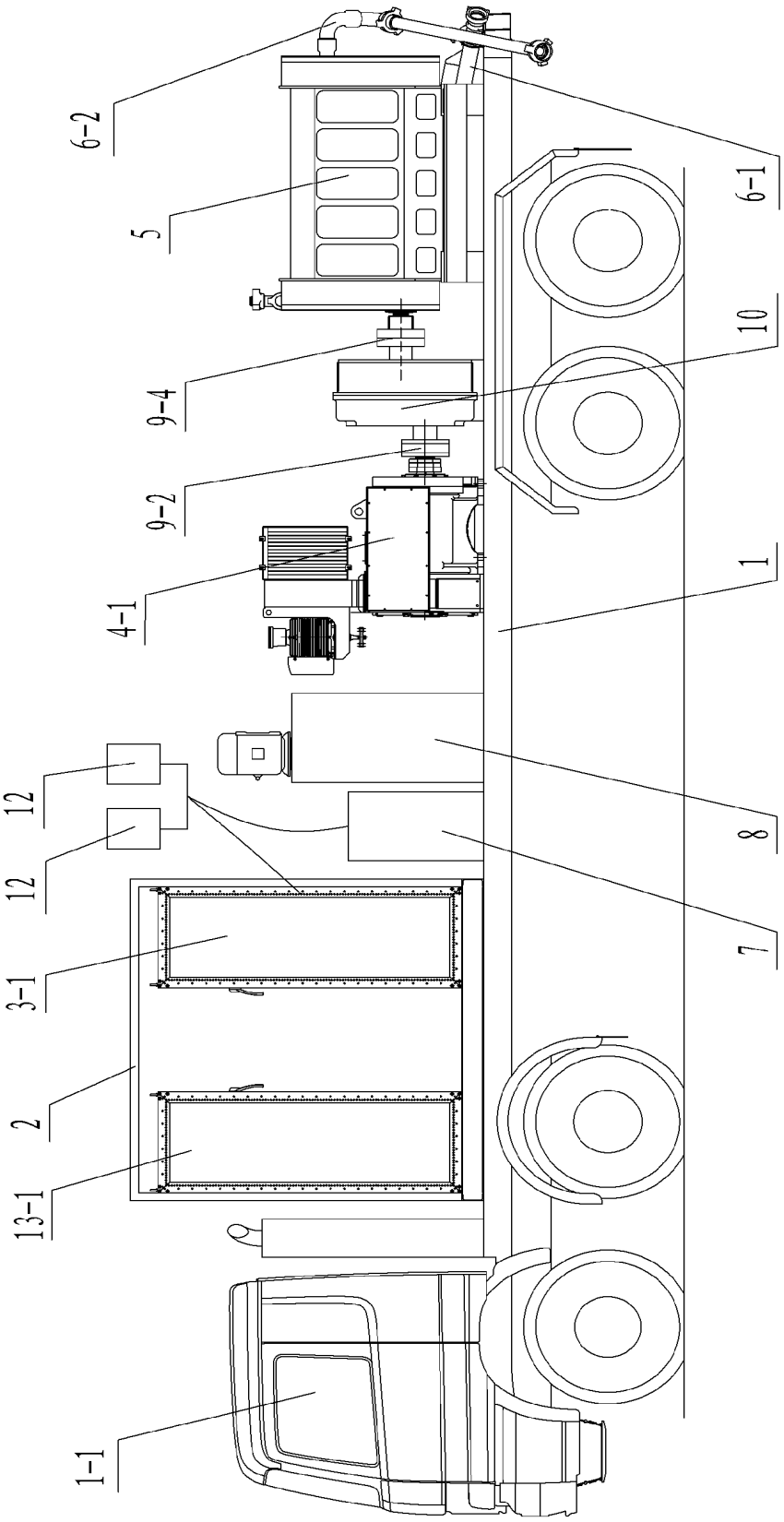


图 2

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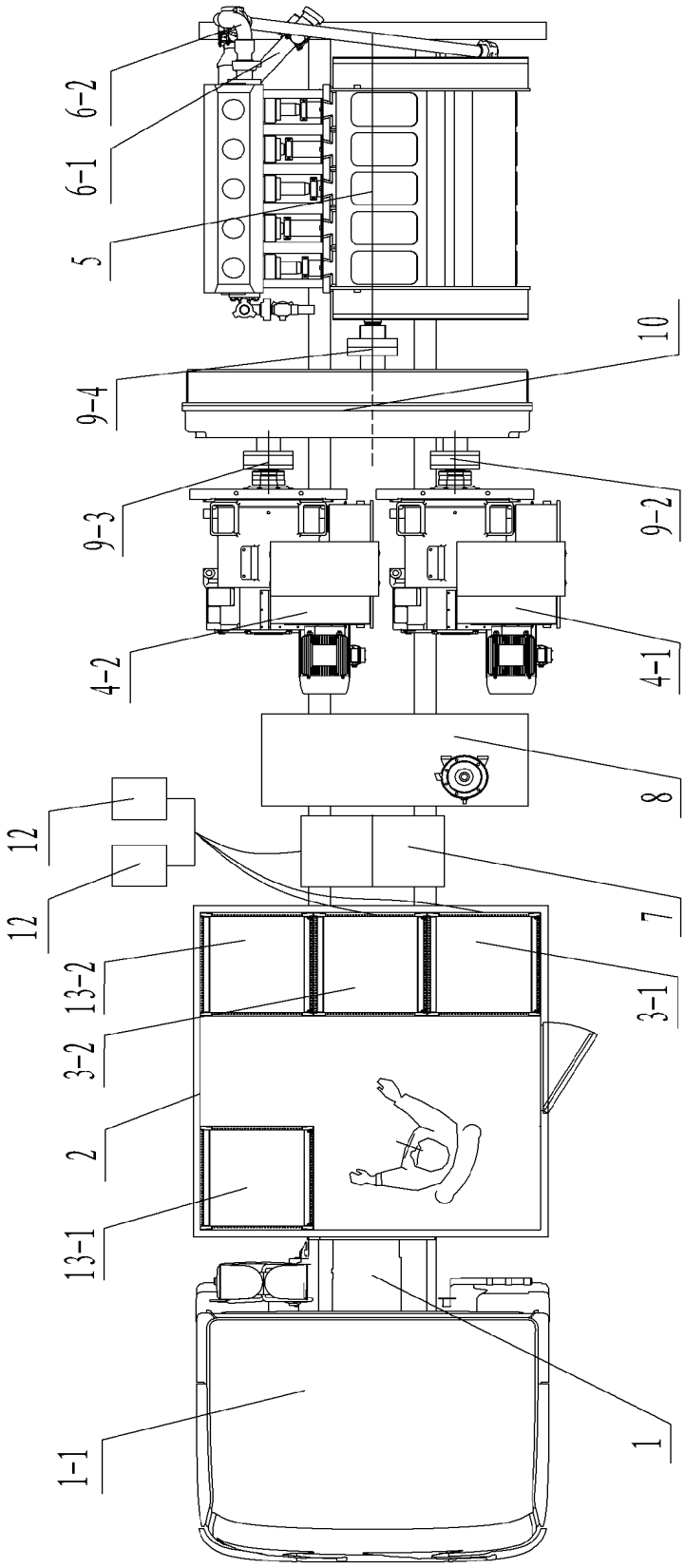


图 3

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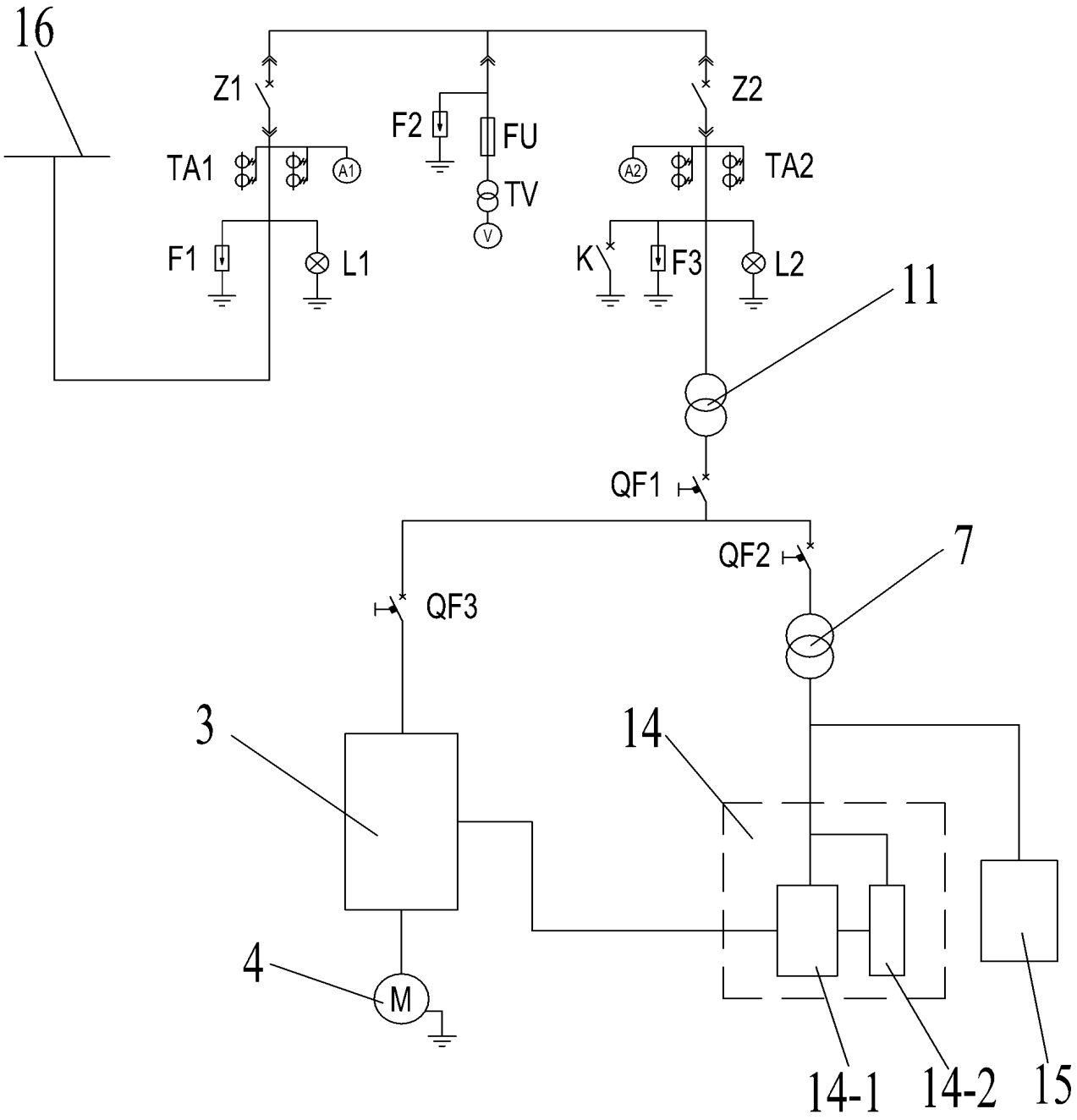


图 4

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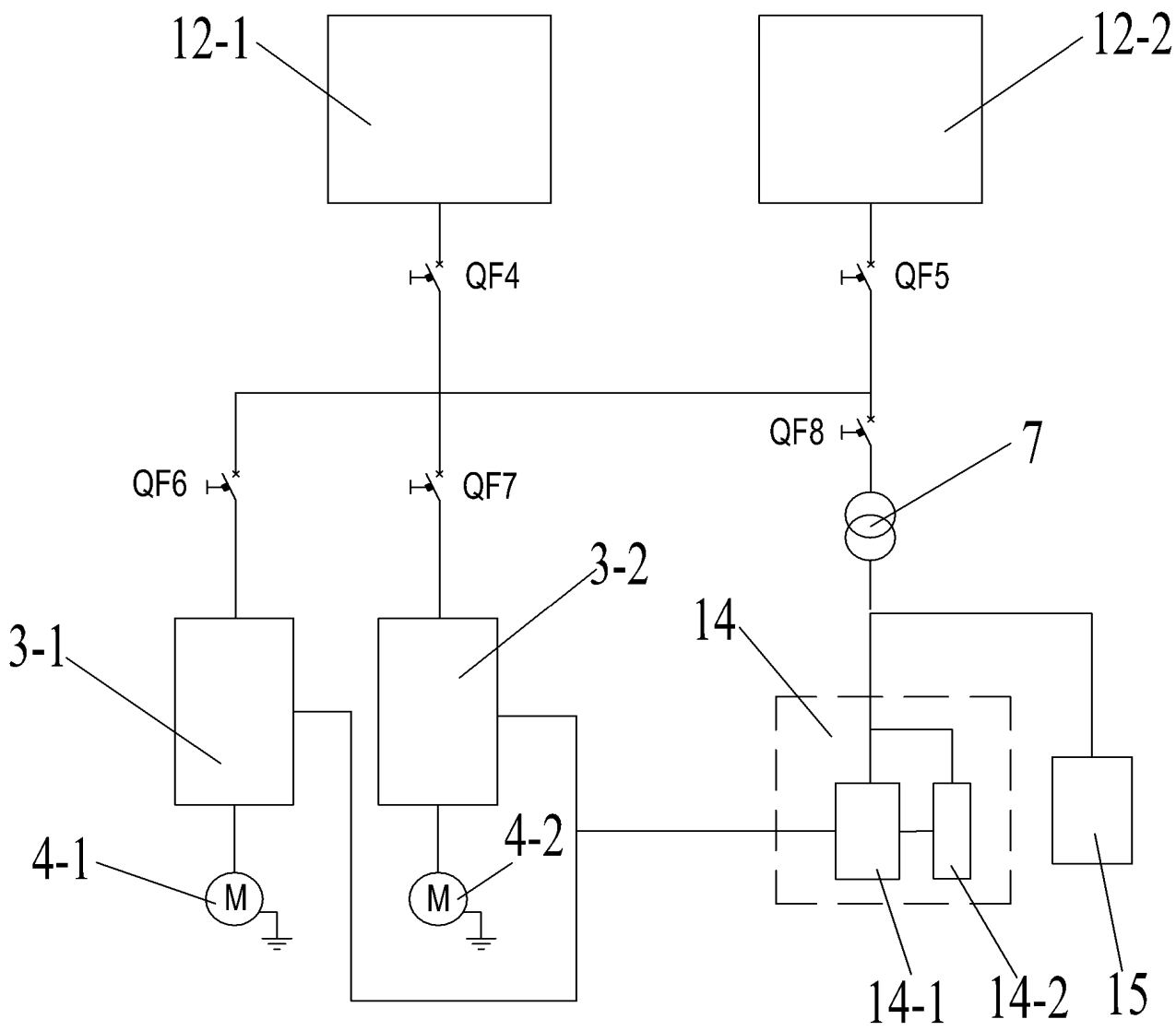


图 5

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CN201687513U

Underground borehole hydraulic fracturing system

Publication Number: CN201687513U

Application Number: CN2010202092857U

Priority Date: May 31, 2010

Filing Date: May 31, 2010

Publication Date: December 29, 2010

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Assignees: N/A

Legal Status: N/A

Abstract

The utility model discloses an underground borehole hydraulic fracturing system which comprises a borehole sealing device, a high pressure injection pump, a power device and an electrical cabinet; the electrical cabinet is electrically connected with the power device, the power device is in transmission connection with the high pressure injection pump, the high pressure injection pump is connected with the borehole sealing device by a high pressure hose, and the electrical cabinet is connected with a ground monitoring control device by a control conducting wire. The underground borehole hydraulic fracturing system has small volume, easy operation, high safety, can realize the underground borehole hydraulic fracturing process through ground operation, achieves the purposes of gas control and coal seam gas exploitation, remarkably improves the underground single bore drainage ability, has good market prospect and is easy for popularization and application.

Claims

1. Hydraulic fracturing a downhole drilling system, characterized in that: sealing means, high-pressure injection pump, the power unit and control cabinet, cabinet and power means electrically connected to the power means connected to drive the high-pressure injection pump, by a high pressure injection pump comprising high-pressure hose and sealing means connected to the monitoring control cabinet is connected to ground via a control line means.

2. The downhole drilling according to claim 1 hydraulic fracturing system characterized in that: said system is provided over a data line connected by two probes, probe and ground monitoring and control device.

3. The downhole of claim 12 or claim hydraulic fracturing drilling system, wherein: said sealing means comprises a sealing device, and the anchor hole of the connecting pipe, and sealing the rear end connecting bore tube connected to the tip, the bore high pressure hose connection pipe connected to the rear end, the anchor hole provided in the rear of the connection pipe.

4. The downhole drilling the hydraulic fracturing system of claim 3, characterized in that: said power means comprises a motor proof, explosion-proof motor is connected via a transmission to drive the high-pressure injection pump.

Description

Description

Translated from Chinese

Hydraulic fracturing downhole drilling system

FIELD

[0001] The present invention belongs to a technical field Mine Gas Control development, in particular, it relates to a downhole drilling system of hydraulic fracturing.

Background technique

[0002] hydraulic fracturing downhole drilling coal seam gas as an important process of governance and development of coalbed methane, coal can increase the amount of gas drainage hole and concentration, improve high gas pumping efficiency, thereby inhibiting the occurrence of accidents and speed up gas the development of coalbed methane industry.

However, due to downhole fracturing process conditions and limitations, it is necessary to device miniaturization, simplification, and easy operation, high safety.

But currently there is no downhole drilling for hydraulic fracturing equipment.

Although CBM fracturing equipment has been very mature, but limited to its large size, it can not go down to use.

SUMMARY

[0003] The present invention to solve the shortcomings of the prior art, there is provided a downhole specifically for use in the hydraulic fracturing system of the mine drilling.

[0004] In order to solve the above problems, the present invention adopts the following technical solutions: hydraulic fracturing a downhole drilling system, comprising plugging means, high-pressure injection pump, the power unit and control cabinet, power means electrically connected to the cabinet, power means connected to drive the high-pressure injection pump, high-pressure injection pump via a high pressure hose connected to the sealing means, the monitoring control cabinet is connected to ground via a control line means.

The [0005] above the system is provided with two probes, probe and ground monitoring and control device is connected via a data line.

The [0006] plugging means comprises a sealing device, and the anchor hole of the connecting pipe, and sealing the rear end hole of the connecting pipe connected to a front end, a rear end hole of the connecting pipe connected to the high-pressure hose, is provided in the anchor a rear bore of the connection pipe.

[0007] The flameproof power means comprises a motor, explosion-proof motor is connected via a transmission to drive the high-pressure injection pump.

[0008] With the above technical solution, sealing has a high expansion ratio, high compressive strength, good sealing performance, adaptability, etc; hole connecting pipe of any length in meters, it is possible to adapt the underground small operating space, conditions complex features, and resistant to high pressure (40MPa or more), while the joint portion of the tube connecting hole requirements butt firmly, tightly; anchor is simple, high compressive strength, high friction with the hole wall, ingenious characteristics, so that the hole can be plugged tube and connector bore is not moved by the high pressure water; high-pressure hose with a high compressive strength, butt firmly, tightly sealed, may be determined according to the characteristics required length; high-pressure injection pump having simple, small, large displacement (Im3Aiin), high pressure (40MPa or more), the boosting speed is fast, able to adapt to conditions downhole, high moisture resistance, explosion-proof security characteristics; high voltage transmission can be controlled by using different shift and the pressure of the pump displacement, small, safe explosion-proof; the motor can provide enough power a high pressure pump, explosion; downhole control cabinet

The whole process of hydraulic fracturing hole, having a pump, the pump stops, the high pressure pump is heated so that the operator can be away from the high pressure region; a probe to monitor the location of fracturing the fracturing case, a probe to monitor downhole drilling apparatus hydraulic fracturing ; ground monitoring and control means, connected to the probe and a downhole electrical control cabinet through a dedicated data line, and the construction returns downhole fracturing scene data, so that safe, accurate and real-time record.

[0009] The present invention is small, easy to operate, safe, it can be operated on the ground by hydraulic fracturing downhole drilling technology, to solve the soft, low permeability, high gas control sudden coal and coalbed methane development problems of implementation, significantly improve the underground hole extraction capacity, with good market prospects and easy application.

BRIEF DESCRIPTION

[0010] FIG. 1 is a structural diagram of the present invention novel.

Detailed ways

[0011] As shown, the present invention is a downhole hydraulic fracturing drilling system 1, comprising sealing means, high-pressure injection pump 1, power cabinet 2, and means, connected to the cabinet 2 electric power plant, the power means high-pressure injection pump connected to a drive, a high-pressure injection pump 13 is connected to the high pressure hose through the plugging means, cabinet 2 is connected to ground monitoring and control device 4 via a control line 5.

Power means comprises a motor 6 proof, explosion-proof motor 6 is connected to the high-pressure injection pump via a transmission gear 7.

Plugging means 11 is inserted into the pre-seam construction which bore 12, the sealing means comprises a sealing device 8, the connection pipe 9 and the anchor hole 10, sealing the bore 8 is connected to the rear end of the tip of the connecting pipe 9 the drilling depth settings 9, a plurality of connecting tube bore root and sequentially end to end, a rear end hole 9 connected to the high-pressure pipe connecting hose 3, the anchor hole 10 provided in the rear portion of the connection pipe 9, the anchor 10 external blocking bore 12.

The system is provided above the probe 13 and the probe 14, the probe 13 and the probe 14 and the ground monitoring apparatus 5 is connected via a control data line 15 and data line 16, respectively, the case of fracturing the fracturing location monitoring probe 13, the probe 14 to monitor downhole drilling hydraulic fracturing equipment.

Cabinet 2, the control device 5 as monitoring ground prior art, will not be repeated.

(19)中华人民共和国国家知识产权局

(12)实用新型专利

(10)授权公告号 CN 201687513 U
(45)授权公告日 2010.12.29

(21)申请号 201020209285.7

(22)申请日 2010.05.31

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(51)Int.Cl.
E21F 7/00(2006.01)
E21B 43/26(2006.01)

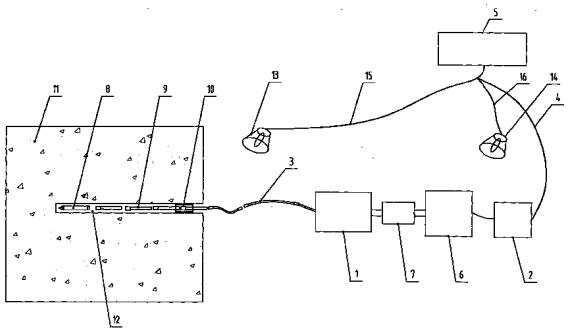
权利要求书 1 页 说明书 2 页 附图 1 页

(54)实用新型名称

井下钻孔水力压裂系统

(57)摘要

本实用新型公开了一种井下钻孔水力压裂系统，包括封孔装置、高压注水泵、动力装置和电控柜，电控柜与动力装置电连接，动力装置与高压注水泵传动连接，高压注水泵通过高压软管与封孔装置连接，电控柜通过控制导线与地面监测控制装置连接。本实用新型体积小、易操作、安全性高，可以通过在地面操作实现井下钻孔水力压裂工艺，达到瓦斯治理和煤层气开发的目的，显著提高井下单孔抽采能力，具有良好的市场前景，易于推广应用。



CN 201687513 U

1. 井下钻孔水力压裂系统，其特征在于：包括封孔装置、高压注水泵、动力装置和电控柜，电控柜与动力装置电连接，动力装置与高压注水泵传动连接，高压注水泵通过高压软管与封孔装置连接，电控柜通过控制导线与地面监测控制装置连接。

2. 根据权利要求 1 所述的井下钻孔水力压裂系统，其特征在于：所述系统上方设有两个探头，探头与地面监测控制装置通过数据线连接。

3. 根据权利要求 1 或 2 所述的井下钻孔水力压裂系统，其特征在于：所述封孔装置包括封孔器、孔内连接管和锚固器，封孔器后端与孔内连接管前端连接，孔内连接管后端与高压软管连接，锚固器设在孔内连接管后部。

4. 根据权利要求 3 所述的井下钻孔水力压裂系统，其特征在于：所述动力装置包括隔爆电机，隔爆电机通过变速器与高压注水泵传动连接。

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井下钻孔水力压裂系统

技术领域

[0001] 本实用新型属于一种矿井瓦斯治理开发技术领域，尤其涉及一种井下钻孔水力压裂系统。

背景技术

[0002] 井下钻孔水力压裂作为煤层瓦斯治理及煤层气开发的一项重要工艺，可以增加煤的单孔瓦斯抽采量及浓度，提高瓦斯抽采效率，从而抑制瓦斯事故的发生和加快煤层气产业的发展。但由于井下条件及压裂工艺限制，所以需要设备小型化、简单化、易操作、安全性高。但目前尚没有针对井下钻孔水力压裂的设备。地面煤层气压裂设备尽管已经很成熟，但限于其庞大的体积，也无法下井使用。

实用新型内容

[0003] 本实用新型为了解决现有技术中的不足之处，提供一种专门适用于矿井内使用的井下钻孔水力压裂系统。

[0004] 为解决上述技术问题，本实用新型采用如下技术方案：井下钻孔水力压裂系统，包括封孔装置、高压注水泵、动力装置和电控柜，电控柜与动力装置电连接，动力装置与高压注水泵传动连接，高压注水泵通过高压软管与封孔装置连接，电控柜通过控制导线与地面监测控制装置连接。

[0005] 所述系统上方设有两个探头，探头与地面监测控制装置通过数据线连接。

[0006] 所述封孔装置包括封孔器、孔内连接管和锚固器，封孔器后端与孔内连接管前端连接，孔内连接管后端与高压软管连接，锚固器设在孔内连接管后部。

[0007] 所述动力装置包括隔爆电机，隔爆电机通过变速器与高压注水泵传动连接。

[0008] 采用上述技术方案，封孔器具有膨胀率高、抗压强度大、密封性能好、适应性强等优点；孔内连接管以米为单位的任意长度，能够适应井下操作空间小、条件复杂的特点，并且能够抗高压力（40MPa 以上），同时孔内连接管的接头部分要求对接牢固、紧密；锚固器具有操作简单、抗压能力高、与孔壁摩擦力大、制作精巧的特点，能够使孔内封孔器及连接管在高压水的作用下不在孔内移动；高压软管具有抗压能力高、对接牢固、密封严实、可根据需要确定长度的特点；高压注水泵具有操作简单、体积小、排量大（$1m^3/min$）、压力高（40MPa 以上）、升压速度快、能够适应井下复杂条件、抗潮湿能力强、安全防爆的特点；变速器能够通过使用不同档位控制高压泵的排量及压力，体积小，安全防爆；电机能够提供高压泵足够的动力，防爆；电控柜控制井下钻孔水力压裂的整个过程，具有开泵、停泵、为高压泵加热、使操作者能够远离高压区；一个探头监控压裂地点的压裂情况，一个探头监控井下钻孔水力压裂的设备；地面监测控制装置，通过专用的数据线连接井下探头及电控柜，返回井下压裂场景及施工数据，做到安全操作，准确实时记录。

[0009] 本实用新型体积小、易操作、安全性高，可以通过在地面操作实现井下钻孔水力压裂工艺，达到解决松软、低透、高突煤体的瓦斯治理及煤层气开发问题，显著提高井下单孔

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抽采能力，具有良好的市场前景，易于推广应用。

附图说明

[0010] 图 1 是本实用新型的结构示意图。

具体实施方式

[0011] 如图 1 所示，本实用新型的井下钻孔水力压裂系统，包括封孔装置、高压注水泵 1、动力装置和电控柜 2，电控柜 2 与动力装置电连接，动力装置与高压注水泵 1 传动连接，高压注水泵 1 通过高压软管 3 与封孔装置连接，电控柜 2 通过控制导线 4 与地面监测控制装置 5 连接。动力装置包括隔爆电机 6，隔爆电机 6 通过变速器 7 与高压注水泵 1 传动连接。封孔装置插设到煤层 11 当中预先施工的钻孔 12 中，封孔装置包括封孔器 8、孔内连接管 9 和锚固器 10，封孔器 8 后端与孔内连接管 9 前端连接，根据钻孔深度，孔内连接管 9 设置若干根并依次首尾相连，孔内连接管 9 后端与高压软管 3 连接，锚固器 10 设在孔内连接管 9 后部，锚固器 10 的外部封堵钻孔 12。系统上方设有探头 13 和探头 14，探头 13 和探头 14 与地面监测控制装置 5 分别通过数据线 15 和数据线 16 连接，探头 13 监控压裂地点的压裂情况，探头 14 监控井下钻孔水力压裂的设备。电控柜 2、地面监测控制装置 5 为现有技术，不再赘述。

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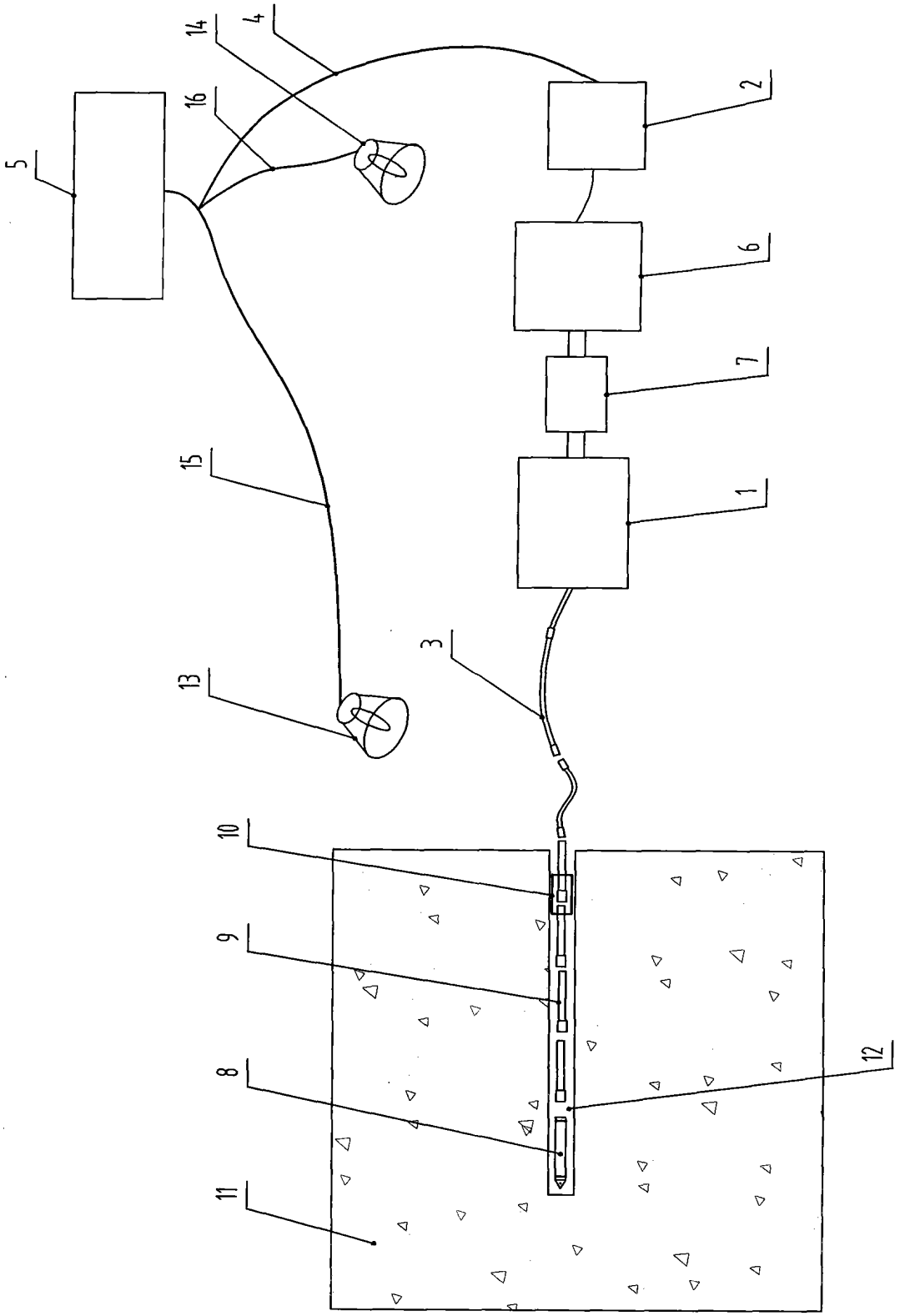


图 1

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Coal mine underground pulsed hydraulic fracturing equipment

Publication Number: CN202023547U

Application Number: CN2011201339382U

Priority Date: April 29, 2011

Filing Date: April 29, 2011

Publication Date: November 02, 2011

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Assignees: N/A

Legal Status: N/A

Abstract

The utility model discloses coal mine underground pulsed hydraulic fracturing equipment which is suitable for underground hydraulic fracturing operation in a coal bed with high methane content and low gas permeability. The coal mine underground pulsed hydraulic fracturing equipment comprises frequency conversion equipment, a pulsed injection pump, an automatic control water tank and a fracturing pipe. The frequency conversion equipment is connected with the pulsed injection pump through a transmission shaft, the automatic control water tank is connected with the pulsed injection pump through a water inlet pipe of the pulsed injection pump, and the pulsed injection pump is connected with the fracturing pipe in a drill hole through a pulsed water outlet pipe of the pulsed injection pump. The frequency conversion equipment comprises a mining flameproof filter reactor, a mining flameproof and intrinsically safe alternating current frequency converter and a mining flameproof variable frequency motor. The pulsed water frequency of the pulsed injection pump is changed through adjusting the frequency parameter of the mining flameproof and intrinsically safe alternating current frequency converter, and the coal bed is fractured by a pulsed hydraulic effect generated through the periodic variation of high-pressure pulsed water in a coal body drill hole, therefore, a coal bed pressure release and permeability improvement effect is achieved. In addition, controllable and adjustable pulsed hydraulic fracturing pulsed water frequency can be achieved.

Claims

1. An underground mine pulsation of hydraulic fracturing apparatus comprising: a main device flameproof filter reactor (1), mine explosion-proof and intrinsically safe AC inverter (2), mine explosion frequency the motor (5), pulsating injection pump (7), automatic control of the water tank (9), inserted into the borehole fracturing sealed tube (11) inside (13) configured; flameproof filter reactor (1) aND mINERAL is connected between the (2) reactor cable (3) explosion-proof and intrinsically safe AC drive; mine explosion-proof and intrinsically safe AC inverter (2) and the mine explosion-proof connection between the inverter motor (5) with a drive cable (4); mine explosion inverter motor (5) to the pulsating injection pump (7) via a drive shaft (6) is connected; pulsating injection pump (7) is inserted into the water inlet is connected to the automatic control tank (9) pulsations injection pump inlet (8); pulsating injection pump (7) is provided at the outlet is connected to the fracturing pulsation tube (11) of the injection inlet of the pump outlet (10).

2. The coal mine pulsating hydraulic fracturing apparatus according to claim 1, characterized in that: said pulsating injection pump outlet pipe (10) is provided with a flow control valve.

Description

Description

Translated from Chinese

Pulsating hydraulic fracturing underground coal mine equipment

FIELD

[0001] The present invention relates to coal mine pulsating hydraulic fracturing equipment, especially for coal mine gas control area.

Background technique

[0002] Hydraulic fracturing is one of the key technologies of the current coal mine gas control area.

By region of hydraulic fracturing coal seam permeability can be increased to improve gas pumping rate, gas pressure release seam, changing the nature of the coal body, thereby reducing the purpose of coal and gas outburst, to the coal and gas extraction.

For high gas permeability is low, a single seam, hydraulic fracturing equipment currently used common problems are: difficulties in coal water, injection water is small, insufficient fractured, stress concentration area, is not obvious seam permeability, resulting in the drill and the amount of drainage holes low concentrations drainage, drainage drilling faster decay rate, it is difficult to achieve the desired effect.

SUMMARY

[0003] The object of the present invention to overcome the deficiencies of the prior art, there is provided a coal water convenient, water volume, to facilitate hydraulic fracturing underground mine pulsating gas drainage device.

[0004] aspect of the present invention to solve the technical problem is: equipment consists of flameproof filter reactors, mine explosion-proof and intrinsically safe AC drive, injection pump mine explosion-proof motor frequency, pulsating automatic control tanks, tubes inserted into the borehole a fracturing seal segment; flameproof filter reactor and have essentially flameproof reactor cable connection between the safety AC drive; flameproof AC drive and intrinsically safe mine explosion frequency between the drive motor is connected to a cable; mine explosion-proof injection pump inverter motor shaft is connected via the pulsating; pulsation at the inlet of the injection pump is connected to the automatic control is inserted in the tank pulsating injection pump inlet; pulsating injection pump provided at the outlet pulsations and fracturing injection inlet connected to the pump outlet; a pulsating injection flow rate control valve provided on the pump outlet.

[0005] Advantageous Effects: As a result of the above technical solution, mine explosion-proof and intrinsically safe explosion-proof AC drive connection with the filter reactor ore achieved grid suppressing waveform distortion function; by adjusting Flameproof and intrinsically safe AC inverter control mine explosion frequency motor speed; mine explosion-proof injection pump connected to the motor pulsation

frequency, the pulsation frequency Remineralization water injection pump explosion frequency changes with motor speed, and ultimately the pulsation of hydraulic fracturing water pulse frequency controlled, adjustable.

Apparatus by hydraulic fracturing, hydraulic fracturing injection frequency adjustment, achieve water ripple pulse frequency controlled hydraulic fracturing, adjustable to achieve target seam integral pressure relief antireflection effect.

Easy to operate, easy coal injection, injection amount, to facilitate gas drainage, strong controllability characteristics.

BRIEF DESCRIPTION

[0006] Figure 1 is a schematic view of the structure of the new hydraulic fracturing underground utility equipment pulsation coal.

[0007] FIG: 1 a flameproof filter reactor, 2 - Flameproof and intrinsically safe AC drive 3 - reactor cable, a drive cable 4, 5 - mine explosion frequency motor , 6- shaft, 7-- pulsating injection pump, 8 - pulsating injection pump inlet, automatic control of a water tank 9, a pulsating injection pump outlet pipe 10, 11 a pipe fracture, a bore 12, a bore seal 13 segment.

Detailed ways

[0008] DRAWINGS Embodiments of the present invention described below a further binding:

[0009] The present invention pulsating hydraulic fracturing coal mine equipment consists flameproof filter reactor 1, flameproof and intrinsically safe AC converter 2, the motor 5 mine explosion frequency pulsating injection pump 7 , automatic control of the water tank 9, the sealing bore inserted in the tube 11 fracturing constituting 13; reactance between the cable connector 2 flameproof filter reactor 1 flameproof and intrinsically safe AC inverter 3 ; mine explosion-proof and intrinsically safe 2 and the AC drive mine explosion frequency between the drive motor 5 is connected to the cable 4; mineral water injection pump 7 is connected via the drive shaft 6 with explosion-proof motor 5 and the ripple frequency; pulsating injection pump water inlet 7 is connected to the automatic control tank 9 is inserted into the inlet 8 pulsating injection pump; pulsating injection pump 7 is provided at the outlet pipe connected to the pulsating fracturing injection pump outlet pipe 11 an inlet 10, an injection pump pulsation with the flow control valve 10 on the pipe.

In operation, drilling coal seam fracturing orifice 12 is inserted into the tube 11, the seal required to complete the seal segment 13 in accordance with the high-pressure bore drilled, fracturing the tube so that the bore 12 in the body 11, the tube 11 fracturing exposed borehole orifice 15cnT30Cm.

Mine explosion frequency motor 5 through the shaft 6 is connected to the pulsating injection pump 7, the tank 9 via automatically controlled pulsating injection pump inlet 7 pump 8 is connected to the pulsating injection, injection pump outlet 10 is connected to the pulsation tube 11 fracturing the borehole.

In turn starts mine explosion-proof and intrinsically safe AC inverter 2, inverter motor 5 mine explosion implementation of coal seam water injection to fracture.

The preset parameters, adjusting the output frequency Flameproof and intrinsically safe AC inverter 2, changing the pulsation frequency of water injection pump 7, can achieve a controllable pulse frequency pulsating injection pump, is adjustable.

(19)中华人民共和国国家知识产权局

(12)实用新型专利

(10)授权公告号 CN 202023547 U
(45)授权公告日 2011.11.02

(21)申请号 201120133938.2

(22)申请日 2011.04.29

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(51)Int.Cl.
E21B 43/26(2006.01)

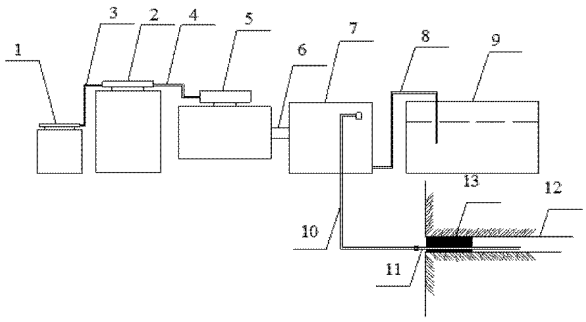
权利要求书 1 页 说明书 2 页 附图 1 页

(54)实用新型名称

煤矿井下脉动水力压裂设备

(57)摘要

一种煤矿井下脉动水力压裂设备，适用于高瓦斯低透气性煤层井下水力压裂作业。它由变频设备、脉动注水泵、自动控制水箱、压裂管组成。变频设备通过传动轴连接脉动注水泵，自动控制水箱通过脉动注水泵进水管连接脉动注水泵，脉动注水泵通过脉动注水泵脉动出水管连接钻孔内压裂管。变频设备由矿用隔爆型滤波电抗器、矿用隔爆兼本质安全型交流变频器、矿用防爆变频电机组成。通过调节矿用隔爆兼本质安全型交流变频器频率参数来改变脉动注水泵脉冲水频率，利用高压脉冲水在煤体钻孔内部的周期性变化所产生的脉冲水力效应压裂煤层，达到煤层卸压增透效果。可实现脉动水力压裂脉冲水频率可控、可调。



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1. 一种煤矿井下脉动水力压裂设备，其特征在于：设备主要由矿用隔爆型滤波电抗器（1）、矿用隔爆兼本质安全型交流变频器（2）、矿用防爆变频电机（5）、脉动注水泵（7）、自动控制水箱（9）、插入钻孔密封段（13）内的压裂管（11）构成；矿用隔爆型滤波电抗器（1）与矿用隔爆兼本质安全型交流变频器（2）之间连接有电抗器电缆（3）；矿用隔爆兼本质安全型交流变频器（2）与矿用防爆变频电机（5）之间连接有变频器电缆（4）；矿用防爆变频电机（5）与脉动注水泵（7）经传动轴（6）相连接；脉动注水泵（7）的进水口处连接有插入自动控制水箱（9）中的脉动注水泵进水管（8）；脉动注水泵（7）的出水口处设有与压裂管（11）入口相连的脉动注水泵出水管（10）。

2. 根据权利要求 1 所述的煤矿井下脉动水力压裂设备，其特征在于：所述的脉动注水泵出水管（10）上设有流量控制阀。

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煤矿井下脉动水力压裂设备

技术领域

[0001] 本实用新型涉及煤矿井下脉动水力压裂设备，尤其适用于煤矿井下区域的瓦斯治理。

背景技术

[0002] 水力压裂是当前煤矿井下区域瓦斯治理主要技术之一。通过对区域煤体实施水力压裂可以增大煤层透气性，提高瓦斯抽采率，释放煤层瓦斯压力，改变煤体性质，从而降低煤与瓦斯突出危险性，达到煤与瓦斯共采的目的。对于高瓦斯、低透气性、单一煤层，目前使用的水力压裂设备常见问题有：煤体注水困难、注水量小、裂隙发育不充分、产生应力集中区、煤层透气性提高不明显，导致钻孔抽采量及抽采浓度低，钻孔抽采衰减速度快，难以达到理想效果。

发明内容

[0003] 本实用新型的目的是克服已有技术中的不足之处，提供一种煤体注水方便、注水量大、便于瓦斯抽采的煤矿井下脉动水力压裂设备。

[0004] 本实用新型解决其技术问题所采用的技术方案是：设备主要由矿用隔爆型滤波电抗器、矿用隔爆兼本质安全型交流变频器、矿用防爆变频电机、脉动注水泵、自动控制水箱、插入钻孔密封段内的压裂管构成；矿用隔爆型滤波电抗器与矿用隔爆兼本质安全型交流变频器之间连接有电抗器电缆；矿用隔爆兼本质安全型交流变频器与矿用防爆变频电机之间连接有变频器电缆；矿用防爆变频电机与脉动注水泵经传动轴相连接；脉动注水泵的进水口处连接有插入自动控制水箱中的脉动注水泵进水管；脉动注水泵的出水口处设有与压裂管入口相连的脉动注水泵出水管；所述的脉动注水泵出水管上设有流量控制阀。

[0005] 有益效果：由于采用了上述技术方案，矿用隔爆型滤波电抗器与矿用隔爆兼本质安全型交流变频器连接，实现了抑制电网波形畸变的功能；通过调节矿用隔爆兼本质安全型交流变频器控制矿用防爆变频电机转速；矿用防爆变频电机连接脉动注水泵，矿用防爆变频电机转速的变化影响脉动注水泵的注水频率，最终实现脉动水力压裂脉冲水频率可控、可调。通过水力压裂设备，调节水力压裂注水频率，实现脉动水力压裂脉冲水频率可控、可调，达到目标煤层整体卸压增透效果。具有操作方便、煤体注水方便、注水量大、便于瓦斯抽采、可控制性强的特点。

附图说明

[0006] 图 1 为本实用新型的煤矿井下脉动水力压裂设备结构示意图。

[0007] 图中：1 —矿用隔爆型滤波电抗器，2 —矿用隔爆兼本质安全型交流变频器，3 —电抗器电缆，4 —变频器电缆，5 —矿用防爆变频电机，6 —传动轴，7 —脉动注水泵，8 —脉动注水泵进水管，9 —自动控制水箱，10 —脉动注水泵出水管，11 —压裂管，12 —钻孔，13 —钻孔密封段。

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具体实施方式

[0008] 下面结合附图对本实用新型的一个实施例作进一步的描述：

[0009] 本实用新型的煤矿井下脉动水力压裂设备主要由矿用隔爆型滤波电抗器 1、矿用隔爆兼本质安全型交流变频器 2、矿用防爆变频电机 5、脉动注水泵 7、自动控制水箱 9、插入钻孔密封段 13 内的压裂管 11 构成；矿用隔爆型滤波电抗器 1 与矿用隔爆兼本质安全型交流变频器 2 之间连接有电抗器电缆 3；矿用隔爆兼本质安全型交流变频器 2 与矿用防爆变频电机 5 之间连接有变频器电缆 4；矿用防爆变频电机 5 与脉动注水泵 7 经传动轴 6 相连接；脉动注水泵 7 的进水口处连接有插入自动控制水箱 9 中的脉动注水泵进水管 8；脉动注水泵 7 的出水口处设有与压裂管 11 入口相连的脉动注水泵出水管 10，脉动注水泵出水管 10 上装有流量控制阀。工作时，在煤层钻孔 12 的孔口处插入压裂管 11，按照高压钻孔密封要求完成钻孔密封段 13，使压裂管 11 主体在钻孔 12 内，压裂管 11 外露钻孔孔口 15cm~30cm。矿用防爆变频电机 5 通过传动轴 6 连接脉动注水泵 7，自动控制水箱 9 通过脉动注水泵进水管 8 连接脉动注水泵 7，脉动注水泵出水管 10 连接钻孔内压裂管 11。依次启动矿用隔爆兼本质安全型交流变频器 2、矿用防爆变频电机 5 实施煤层注水至煤层压裂。根据预先设定的参数，可调节矿用隔爆兼本质安全型交流变频器 2 的输出频率，改变脉动注水泵 7 的注水频率，即可实现脉动注水泵脉冲频率可控、可调。

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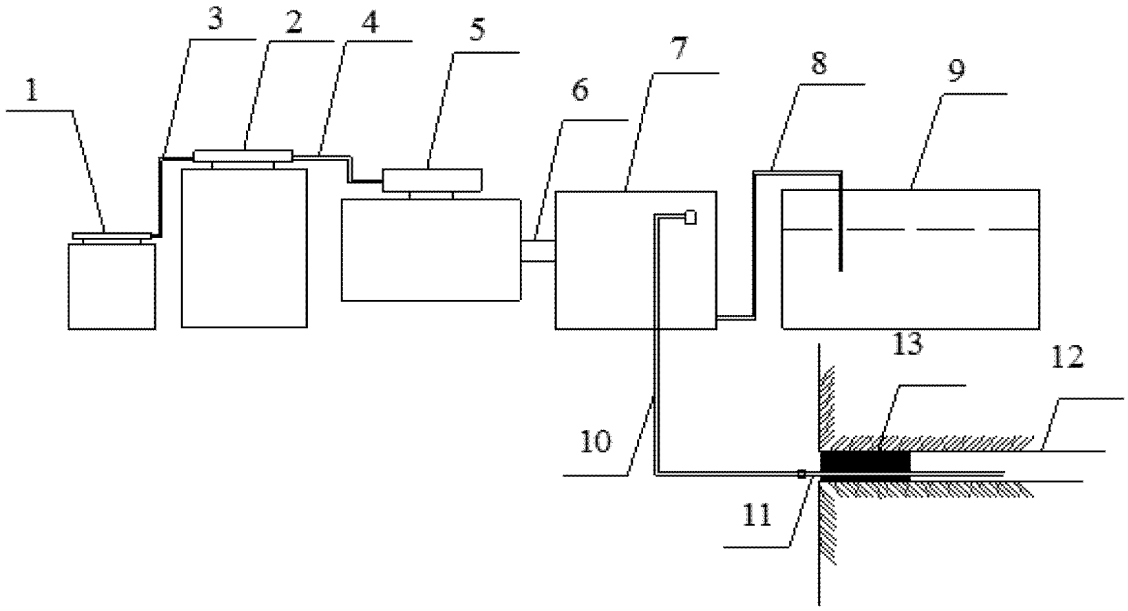


图 1

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DERWENT-ACC-NO: 2004-659178

DERWENT-WEEK: 200554

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TITLE: Noise reducing wall member for e.g. engine or electrical machinery enclosure, has each of sound absorption and sound insulation walls comprising of alternating thin and thick part

INVENTOR: MORIKAWA Y

PATENT-ASSIGNEE: TOSHIBA KK[TOKE]

PRIORITY-DATA: 2003JP-054684 (February 28, 2003)

PATENT-FAMILY:

PUB-NO	PUB-DATE	LANGUAGE
JP 2004264589 A	September 24, 2004	JA
JP 3680061 B2	August 10, 2005	JA

APPLICATION-DATA:

PUB-NO	APPL-DESCRIPTOR	APPL-NO	APPL-DATE
JP2004264589A	N/A	2003JP-054684	February 28, 2003
JP 3680061B2	Previous Publ	2003JP-054684	February 28, 2003

INT-CL-CURRENT:

TYPE	IPC DATE	
CIPP	E01 F 8/00	20060101
CIPS	E04 B 1/86	20060101
CIPS	G10 K 11/16	20060101
CIPS	G10 K 11/172	20060101

ABSTRACTED-PUB-NO: JP 2004264589 A

BASIC-ABSTRACT:

NOVELTY - Each of sound absorption and sound insulation walls (20,30) comprises of alternating thin parts (21,31) and thick parts (22,32). Particle velocity of the sound passing the thick part of the sound absorption wall (20) is greater than a reference velocity. The pressure level of the sound passing the thick part of the sound insulation wall (30) is greater than a sound pressure reference value.

USE - For e.g. engine or electrical machinery enclosure.

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ADVANTAGE - Optimizes thickness of structural member according to mode of sound to be reduced. Achieves weight reduction.

DESCRIPTION OF DRAWING(S) - Figure is a perspective view of a noise reducing wall member.

Sound absorption wall (20)

Thin parts (21,31)

Thick parts (22,32)

Sound insulation wall (30)

CHOSEN-DRAWING: Dwg.1/4

TITLE-TERMS: NOISE REDUCE WALL MEMBER ENGINE ELECTRIC MACHINE ENCLOSE SOUND ABSORB INSULATE COMPRISE ALTERNATE THIN THICK PART

DERWENT-CLASS: P86 Q41 Q43

SECONDARY-ACC-NO:

Non-CPI Secondary Accession Numbers: 2004-522009

LIBERTY EXHIBIT 1002, Page 1992

(19)日本国特許庁(JP)　(12)公開特許公報(A)　(11)特許出願公開番号
特開2004-264589
(P2004-264589A)
(43)公開日　平成16年9月24日(2004.9.24)

(51) Int.Cl.[7]		F I			テーマコード（参考）
G10K	11/172	G10K	11/16	E	2D001
E01F	8/00	E01F	8/00		2E001
E04B	1/86	E04B	1/86	N	5D061

審査請求 有　請求項の数 1　OL　（全 6 頁）

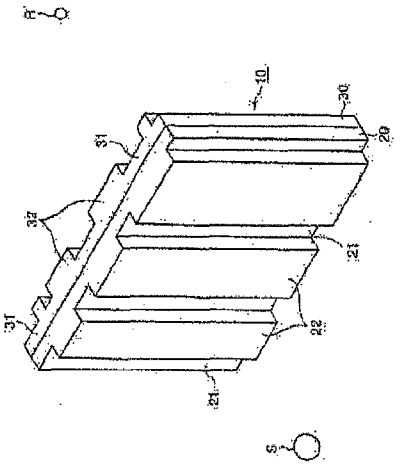
(21) 出願番号　特願2003-54684 (P2003-54684)
(22) 出願日　平成15年2月28日 (2003.2.28)

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最終頁に続く

(54)【発明の名称】壁部材

(57)【要約】
【課題】構造部材の厚さを低減対象音の音響モードにしたがって最適化することで、容積を最小とし軽量とすることが可能な壁部材を提供すること。
【解決手段】積層して配置された吸音壁２０と遮音壁３０とを備え、吸音壁２０は、薄肉部２１と厚肉部２２とを備え、遮音壁３０は、薄肉部３１と厚肉部３２とを備え、低減対象音の音響モードに基づいて、粒子速度が速度基準値よりも大きい部分に対応して厚肉部２２を配置するとともに、音圧レベルが音圧基準値よりも大きい部分に対応して厚肉部３２を配置する。
【選択図】　図１



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(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
15 September 2016 (15.09.2016)

WIPO | PCT

(10) International Publication Number
WO 2016/144939 A1

(51) International Patent Classification:
F17D 3/01 (2006.01) *F17D 1/02* (2006.01)
F17D 1/00 (2006.01) *E21B 7/18* (2006.01)
F17D 1/14 (2006.01) *E21B 33/14* (2006.01)

(21) International Application Number:
PCT/US2016/021336

(22) International Filing Date:
8 March 2016 (08.03.2016)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:

62/130,045	9 March 2015 (09.03.2015)	US
62/130,174	9 March 2015 (09.03.2015)	US
62/195,104	21 July 2015 (21.07.2015)	US

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[Continued on next page]

(54) Title: AUTOMATED OPERATION OF WELLSITE EQUIPMENT

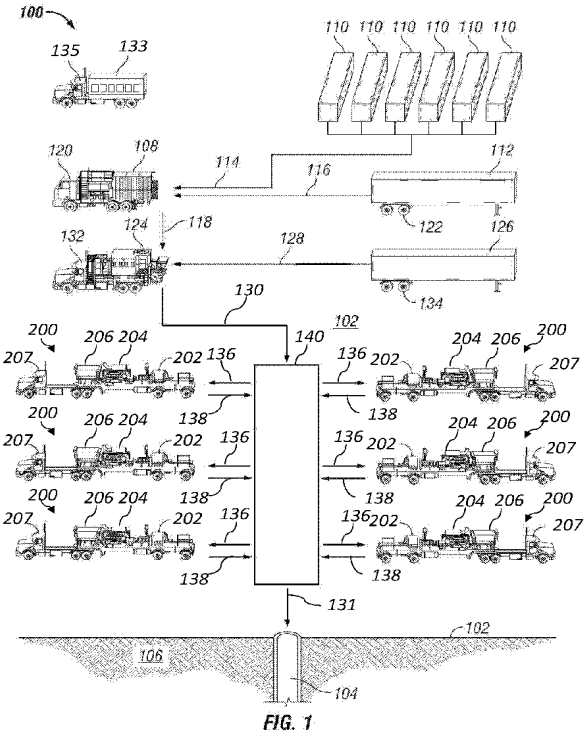


FIG. 1

(57) Abstract: Systems and method for controlling wellsite equipment, including pumps and a manifold having a low-pressure (LP) manifold, having LP ports with LP valves, and a high-pressure (HP) manifold, having HP ports with HP valves and bleed ports with bleed valves. The pumps are fluidly coupled with the LP manifold via LP conduits and with the HP manifold via HP conduits. Communication is established between a controller and the LP valves, the HP valves, the bleed valves, the pumps, and sensors for monitoring pressure within the HP conduits. The controller is operable to, with respect to each pump, cause the LP valve to transition to a closed position, cause the HP and/or bleed valve to transition to an open position, and determine that the HP conduit is not pressurized based on the information generated by the sensors.

WO 2016/144939 A1

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(81) **Designated States** *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) **Designated States** *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Published:

— *with international search report (Art. 21(3))*

AUTOMATED OPERATION OF WELLSITE EQUIPMENT

Cross-Reference to Related Applications

[0001] This application claims priority to and the benefit of U.S. Provisional Application No. 62/130,045, titled "METHOD OF AUTOMATIC MANIFOLD VALVES SANITY TEST," filed March 9, 2015, the entire disclosure of which is hereby incorporated herein by reference.

[0002] This application claims priority to and the benefit of U.S. Provisional Application No. 62/130,174, titled "AUTOMATED RELEASE OF TRAPPED PRESSURE AND FLUID FROM HIGH PRESSURE PUMP LINES," filed March 9, 2015, the entire disclosure of which is hereby incorporated herein by reference.

[0003] This application also claims priority to and the benefit of U.S. Provisional Application No. 62/195,104, titled "REMOTE MANIFOLD VALVE AND PUMP PAIRING TECHNIQUE FOR A MULTI-PUMP SYSTEM," filed July 21, 2015, the entire disclosure of which is hereby incorporated herein by reference.

Background of the Disclosure

[0004] High-volume, high-pressure pumps are utilized at wellsites for a variety of pumping operations. Such operations may include drilling, cementing, acidizing, water jet cutting, hydraulic fracturing, and other wellsite operations. In some pumping operations, several pumps may be fluidly connected to a well via various fluid conduits and at least one manifold. During such operations, the manifold distributes low-pressure fluid from mixer, blender, and/or other units among the pumps and combines pressurized fluid from the pumps for injection into the well. The manifold may have a large physical size and weight to satisfy intended fluid flow rates and operating pressures generated by the pumps. For example, the manifold may convey fluid at a pressure exceeding about 15,000 pounds per square inch (PSI) and a fluid flow rate exceeding about 1,500 gallons per minute (GPM).

[0005] The success of the oilfield operations may be related to many factors, including operational efficiency, failure rates, and safety of the pumps and the manifold at the wellsite. High fluid pressures, flow rates, and vibrations generated by the pumps may cause mechanical fatigue, wear, and other damage to the pumps and various downstream components, including the manifold and various associated fluid sensors, valves, couplings, and conduits. Such mechanical fatigue and wear cause leaks and/or other failures in the pumps and the downstream

components. To ensure that the fluid sensors and valves are not stuck, worn out, or otherwise damaged, human operators at the wellsite approach the manifold during pumping operations to visually and/or manually inspect the fluid sensors and valves, thus exposing themselves to a potentially dangerous environment.

[0006] The operators also manually disconnect the pumps from the manifold, such as after completion of a job, when switching to a different well on a multi-well site, or when changing a pump due to mechanical problems. The task of fluidly disconnecting the pump from the manifold can be dangerous, because high-pressure fluid trapped within the pump and/or the connected conduits may escape, which can lead to serious injuries. The pump and/or the conduits may also contain leftover fluid, which may spill onto the ground when the fluid conduits are disconnected from the pump and/or the manifold, potentially having an adverse environmental impact.

Summary of the Disclosure

[0007] 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 indispensable features of the claimed subject matter, nor is it intended for use as an aid in limiting the scope of the claimed subject matter.

[0008] The present disclosure introduces an apparatus that includes a manifold unit and a controller. The manifold unit includes ports and valves. Each valve is operable to control flow through a corresponding one of the ports. The controller is operable to, with respect to each of the valves: remotely control the valve by transmitting a command signal to the valve to transition the valve from an existing setting to an intended setting; after transmitting the command signal, receive a feedback signal from the valve indicative of an actual setting of the valve; and assess an operational health of the valve based on the intended and actual settings.

[0009] The present disclosure also introduces a method that includes establishing communication between a controller and each of the valves of a manifold unit. Each valve is operable to control flow through a corresponding port of the manifold unit. The method also includes operating the controller to, with respect to each of the valves: remotely control the valve by transmitting a command signal to the valve to transition the valve from an existing setting to an intended setting; after transmitting the command signal, receive a feedback signal from the

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valve indicative of an actual setting of the valve; and assess an operational health of the valve based on the intended and actual settings.

[0010] The present disclosure also introduces an apparatus that includes a manifold unit. The manifold unit includes a low-pressure (LP) manifold having LP ports, LP valves each operable to control flow through a corresponding one of the LP ports, a high-pressure (HP) manifold having HP ports, HP valves each operable to control flow through a corresponding one of the HP ports, bleed ports each fluidly coupled with a corresponding one of the HP ports, and bleed valves each fluidly coupled with and remotely operable to control flow through a corresponding one of the bleed ports from the corresponding HP port. The apparatus also includes pumps, LP conduits each fluidly coupling a corresponding one of the pumps and a corresponding one of the LP ports, HP conduits each fluidly coupling a corresponding one of the pumps and a corresponding one of the HP ports, and sensors each operable to generate information indicative of fluid pressure within a corresponding one of the HP conduits. The apparatus also includes a controller in communication with the LP valves, the HP valves, the bleed valves, the sensors, and the pumps. The controller is operable to, with respect to each of the pumps: cause the LP valve corresponding to the pump to transition to a closed flow position; cause one of the HP valve corresponding to the pump and the bleed valve corresponding to the pump to transition to an open flow position; and determine whether the HP conduit corresponding to the pump is pressurized based on the information generated by the corresponding one of the sensors.

[0011] The present disclosure also introduces a method performed in conjunction with a number of pumps and a manifold unit. The manifold unit includes an LP manifold having LP ports, LP valves each operable to control flow through a corresponding one of the LP ports, an HP manifold having HP ports, HP valves each operable to control flow through a corresponding one of the HP ports, bleed ports each fluidly coupled with a corresponding one of the HP ports, and bleed valves each fluidly coupled with and remotely operable to control flow through a corresponding one of the bleed ports from the corresponding HP port. The method includes fluidly coupling each of the pumps with the LP manifold via LP conduits each fluidly coupling a corresponding one of the pumps with a corresponding one of the LP ports, fluidly coupling each of the pumps with the HP manifold via HP conduits each fluidly coupling a corresponding one of the pumps with a corresponding one of the HP ports, and establishing communication between a controller and each of the LP valves, the HP valves, the bleed valves, the pumps, and a number

of sensors. Each sensor is operable to generate information indicative of fluid pressure within a corresponding one of the HP conduits. The method also includes operating the controller to, with respect to each of the pumps, cause the pump to operate and then: cause the LP valve corresponding to the pump to transition to a closed flow position; and cause one of the HP valve corresponding to the pump and the bleed valve corresponding to the pump to transition to an open flow position. The method also includes operating the controller to, with respect to each of the pumps, determine that the HP conduit corresponding to the pump is not pressurized based on the information generated by the corresponding one of the sensors.

[0012] These and additional aspects of the present disclosure are set forth in the description that follows, and/or may be learned by a person having ordinary skill in the art by reading the materials herein and/or practicing the principles described herein. At least some aspects of the present disclosure may be achieved via means recited in the attached claims.

Brief Description of the Drawings

[0013] The present disclosure is understood from the following detailed description when read with the accompanying figures. It is emphasized that, in accordance with the standard practice in the industry, various features are not drawn to scale. In fact, the dimensions of the various features may be arbitrarily increased or reduced for clarity of discussion.

[0014] FIG. 1 is a schematic view of an example implementation of apparatus according to one or more aspects of the present disclosure.

[0015] FIG. 2 is a schematic view of a portion of an example implementation of the apparatus shown in FIG. 1 according to one or more aspects of the present disclosure.

[0016] FIG. 3 is a perspective view of a portion of an example implementation of the apparatus shown in FIG. 1 according to one or more aspects of the present disclosure.

[0017] FIG. 4 is a sectional view of the apparatus shown in FIG. 3 according to one or more aspects of the present disclosure.

[0018] FIG. 5 is a schematic view of an example implementation of apparatus according to one or more aspects of the present disclosure.

[0019] FIG. 6 is a flow-chart diagram of at least a portion of an example implementation of a method according to one or more aspects of the present disclosure.

[0020] FIG. 7 is a flow-chart diagram of at least a portion of an example implementation of a method according to one or more aspects of the present disclosure.

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Detailed Description

[0021] It is to be understood that the following disclosure provides many different embodiments, or examples, for implementing different features of various embodiments. Specific examples of components and arrangements are described below to simplify the present disclosure. These are, of course, merely examples and are not intended to be limiting. In addition, the present disclosure may repeat reference numerals and/or letters in the various examples. This repetition is for simplicity and clarity, and does not in itself dictate a relationship between the various embodiments and/or configurations discussed. Moreover, the formation of a first feature over or on a second feature in the description that follows may include embodiments in which the first and second features are formed in direct contact, and may also include embodiments in which additional features may be formed interposing the first and second features, such that the first and second features may not be in direct contact.

[0022] FIG. 1 is a schematic view of at least a portion of an example wellsite system 100 according to one or more aspects of the present disclosure. The figure depicts a wellsite surface 102 adjacent to a wellbore 104 and a partial sectional view of the subterranean formation 106 penetrated by the wellbore 104 below the wellsite surface 102. The wellsite system 100 may comprise a first mixer 108 fluidly connected with one or more tanks 110 and a first container 112. The first container 112 may contain a first material and the tanks 110 may contain a liquid. The first material may be or comprise a hydratable material or gelling agent, such as guar, polymers, synthetic polymers, galactomannan, polysaccharides, cellulose, and/or clay, among other examples, and the liquid may be or comprise an aqueous fluid, which may comprise water or an aqueous solution comprising water, among other examples. The first mixer 108 may be operable to receive the first material and the liquid via two or more fluid conduits 114, 116, and mix or otherwise combine the first material and the liquid to form a base fluid, which may be or comprise that which is known in the art as a gel. The first mixer 108 may then discharge the base fluid via one or more fluid conduits 118.

[0023] The first mixer 108 and the first container 112 may each be disposed on corresponding trucks, trailers, and/or other mobile carriers 120, 122, respectively, such as may permit their transportation to the wellsite surface 102. However, the first mixer 108 and/or first container 112 may be skidded or otherwise stationary, and/or may be temporarily or permanently installed at the wellsite surface 102.

[0024] The wellsite system 100 may further comprise a second mixer 124 fluidly connected with the first mixer 108 and a second container 126. The second container 126 may contain a second material that may be substantially different than the first material. For example, the second material may be or comprise a proppant material, such as sand, sand-like particles, silica, quartz, and/or propping agents, among other examples. The second mixer 124 may be operable to receive the base fluid from the first mixer 108 via one or more fluid conduits 118, and the second material from the second container 126 via one or more fluid conduits 128, and mix or otherwise combine the base fluid and the second material to form a mixture, which may be or comprise that which is known in the art as a fracturing fluid. The second mixer 124 may then discharge the mixture via one or more fluid conduits 130. For clarity, the mixture discharged from the second mixer 124 via the one or more fluid conduits 130 will be referred to hereinafter simply as "a fluid."

[0025] The second mixer 124 and the second container 126 may each be disposed on corresponding trucks, trailers, and/or other mobile carriers 132, 134, respectively, such as may permit their transportation to the wellsite surface 102. However, the second mixer 124 and/or second container 126 may be skidded or otherwise stationary, and/or may be temporarily or permanently installed at the wellsite surface 102.

[0026] The fluid may be communicated from the second mixer 124 via the one or more fluid conduits 130 to a manifold unit 140, which may be or comprise what known in the art as a manifold trailer or missile. The manifold unit 140 may be operable to distribute the fluid among a plurality of pump units 200. The manifold unit 140 comprises a low-pressure (LP) portion having a plurality of LP inlet ports and LP outlet ports (shown in FIG. 2). The LP inlet ports are operable to receive the fluid via the one or more fluid conduits 130, and the LP outlet ports are operable to discharge the fluid to the pump units 200 via a corresponding one or more LP fluid conduits 136. The manifold unit 140 also comprises a high-pressure (HP) portion having HP inlet ports and HP outlet ports (shown in FIG. 2). The HP inlet ports are operable to receive the pressurized fluid from the pump units 200 via a corresponding one or more HP fluid conduits 138 and the HP outlet ports are operable to discharge the pressurized fluid. The fluid may then be injected into the wellbore 104, via one or more fluid conduits 131, perhaps through various additional conduits, valves, and/or other hydraulic circuitry fluidly connected between the manifold unit 140 and the wellbore 104.

[0027] The manifold unit 140 may be mounted on one or more trucks, trailers, and/or other mobile carriers (not shown), such as may permit its transportation to the wellsite surface 102. However, the manifold unit 140 may be skidded or otherwise stationary, and/or may be temporarily or permanently installed at the wellsite surface 102.

[0028] Each of the pump units 200 may comprise a pump 202, a prime mover 204, and a heat exchanger 206. The pumps 202 may be implemented as reciprocating pumps, each comprising fluid pressurizing chambers (shown in FIG. 4) and fluid displacing members (shown in FIG. 4). Depending on the size of each pump 202 and the operating speed of the corresponding prime mover 204, each pump 202 may be operable to transfer or otherwise move the fluid into the HP portion of the manifold unit 140 at a flow rate ranging between about 100 GPM and about 1,500 GPM.

[0029] The pump units 200 may each be mounted on corresponding trucks, trailers, and/or other mobile carriers 207, such as may permit their transportation to the wellsite surface 102. However, the pump units 200 may be skidded or otherwise stationary, and/or may be temporarily or permanently installed at the wellsite surface 102. Although the pump fleet of the wellsite system 100 is shown comprising six pump units 200, each disposed on the corresponding mobile carrier 207, a pump fleet comprising other quantities of pump units 200 is also within the scope of the present disclosure.

[0030] The wellsite system 100 may also comprise a control/power center 133, such as may be operable to provide control and/or centralized electric power distribution to one or more portions of the wellsite system 100. The control/power center 133 may be operable to monitor and control at least a portion of the wellsite system 100 during pumping operations. For example, the control/power center 133 may be operable to monitor and control one or more portions of the first mixer 108, the second mixer 124, the pump units 200, and other pumps and/or conveyers (not shown), such as may be operable to move the fluids, materials, and/or mixtures described above. The control/power center 133 may also be operable to monitor and control operations of the manifold unit 140 prior to and during the pumping operations. The control/power center 133 may comprise an engine-generator set, such as a gas turbine generator, an internal combustion engine generator, and/or other sources of electric power. Electric power and/or control signals may be communicated between the control/power center 133 and other wellsite equipment via electric conductors (not shown). However, other means of signal

communication, such as wireless communication, are also within the scope of the present disclosure.

[0031] The control/power center 133 may be disposed on a corresponding truck, trailer, and/or other mobile carrier 135, such as may permit its transportation to the wellsite surface 102. However, the control/power center 133 may be skidded or otherwise stationary, and/or may be temporarily or permanently installed at the wellsite surface 102.

[0032] FIG. 1 depicts the wellsite system 100 as being operable to form fluids and/or mixtures that may be pressurized and individually or collectively injected into the wellbore 104 during hydraulic fracturing of the subterranean formation 106. However, it is to be understood that the wellsite system 100 may be operable to mix and/or produce other mixtures and/or fluids that may be pressurized by the pump units 200 and individually or collectively injected into the wellbore 104 during other oilfield operations, such as drilling, cementing, acidizing, chemical injecting, and/or water jet cutting operations, among other examples.

[0033] FIG. 2 is a schematic view of at least a portion of an example implementation of the manifold unit 140 shown in FIG. 1 according to one or more aspects of the present disclosure. The manifold unit 140 may be utilized in various implementations of a wellsite system. However, for the sake of clarity and ease of understanding, the manifold unit 140 is described below in the context of the wellsite system 100 shown in FIG. 1. Thus, the following description refers to FIGS. 1 and 2, collectively.

[0034] The manifold unit 140 may be or comprise a manifold system operable to distribute LP fluid received from the mixers 108, 124 among the pump units 200 and combine the HP fluid received from the pump units 200 for injection into the wellbore 104. The manifold unit 140 comprises one or more LP manifolds 142, 144 that receive the LP fluid from the mixers 108, 124 via the fluid conduit 130 and distribute the fluid among the pumps 202. The manifold unit 140 also comprises one or more HP manifolds 146 that receive and combine the HP fluid from the pumps 202 and discharge the fluid for injection into the wellbore 104 via the fluid conduit 131.

[0035] The manifold unit 140 also comprises a plurality of fluid valves (described below via reference numbers 153, 157, 163, 167, 173, 177, and 183) operable to control fluid flow into and/or out of the LP and HP manifolds 142, 144, 146. The fluid valves may comprise ball valves, globe valves, butterfly valves, and/or other types of valves operable to shut off fluid flow or otherwise control fluid flow into and/or out of the LP and HP manifolds 142, 144, 146. Each fluid valve may be actuated remotely by an actuator, including an electric actuator, such as a

solenoid or motor, or a fluid actuator, such as a pneumatic or hydraulic cylinder or rotary actuator. The fluid valves may also be manually actuated by the human operators.

[0036] Each fluid valve may also include a corresponding feedback sensor operable to generate a signal or information indicative of an actual position or setting of that fluid valve, such as to monitor in-real time the actual setting of that fluid valve. The actual setting of each fluid valve may include an open-flow setting, a closed-flow setting, and an intermediate or transitional setting between the open-flow and closed-flow settings. Each feedback sensor may be disposed in association with the corresponding fluid valve in a manner permitting sensing of the actual setting of that fluid valve. For example, each feedback sensor may monitor position or orientation of a fluid-blocking portion of the fluid valve, such as a ball or flapper, or another moving portion of the fluid valve, such as a rotating shaft or stem. Each feedback sensor may be coupled with or disposed adjacent the corresponding fluid valve, or each feedback sensor may be incorporated as part of the corresponding fluid valve. The feedback sensors may include proximity sensors, such as capacitive sensors, inductive sensors, magnetic sensors, Hall effect sensors, and/or reed switches, among other examples. The feedback sensors may also or instead include linear position sensors, such as linear potentiometers. The feedback sensors may also or instead include rotary position sensors, such as encoders, rotary potentiometers, synchros, resolvers, and/or rotary variable differential transformers (RVDT), among other examples.

[0037] The manifold unit 140 may comprise a first LP portion or manifold 142 implemented as a fluid conduit arranged in a closed loop configuration. The first LP manifold 142 may comprise a plurality of LP inlet valve assemblies 150, each comprising an LP fluid inlet port 152 operable to fluidly connect with the one or more fluid conduits 130 to receive the fluid from the second mixer 124. The first LP manifold 142 may also comprise a plurality of LP outlet valve assemblies 151 disposed on opposing sides of the first LP manifold 142, each comprising an LP fluid outlet port 156 operable to fluidly connect the first LP manifold 142 with the pumps 202 via corresponding LP fluid conduits 136. Each LP inlet valve assembly 150 may further include an LP fluid valve 153 disposed at a corresponding LP fluid inlet port 152 for selectively opening and closing the corresponding LP fluid inlet port 152, such as may selectively permit or otherwise control fluid flow into the first LP manifold 142. Similarly, each LP outlet valve assembly 151 may include an LP fluid valve 157 disposed at a corresponding LP fluid outlet port 156 for selectively opening and closing the corresponding LP fluid outlet port 156, such as may selectively permit fluid flow out of the first LP manifold 142. Each LP fluid valve 153, 157 may

be selectively shifted or transitioned between open flow and closed flow settings by a corresponding actuator 154, 158, respectively, disposed in association with each LP fluid valve 153, 157. The actual setting of each LP fluid valve 153, 157 may be monitored or otherwise determined in real-time by feedback sensors 155, 159, respectively, disposed in association with the LP fluid valves 153, 157. For clarity, just one of the LP ports 152, 156, the LP fluid valves 153, 157, the actuators 154, 158, and the feedback sensors 155, 159 of the LP inlet and outlet valve assemblies 150, 151, respectively, are identified with numerals in FIG. 2. Although the first LP manifold 142 is shown comprising three LP inlet valve assemblies 150 and eight LP outlet valve assemblies 151, it is to be understood that the first LP manifold 142 may include other quantities of LP inlet and outlet valve assemblies 150, 151.

[0038] The manifold unit 140 may further comprise a second LP portion or manifold 144 implemented as a fluid conduit arranged in a closed loop configuration. The second LP manifold 144 may comprise a plurality of LP inlet valve assemblies 160, each comprising an LP fluid inlet port 162 operable to fluidly connect with the one or more fluid conduits 130 to receive the fluid from the second mixer 124. The second LP manifold 144 may also comprise a plurality of LP outlet valve assemblies 161 disposed on opposing sides of the second LP manifold 144, each comprising an LP fluid outlet port 166 operable to fluidly connect the second LP manifold 144 with the pumps 202 via corresponding LP fluid conduits 136. Each LP inlet valve assembly 160 may further include an LP fluid valve 163 disposed at a corresponding LP fluid inlet port 162 for selectively opening and closing the corresponding LP fluid inlet port 162, such as may selectively permit or otherwise control fluid flow into the second LP manifold 144. Similarly, each LP outlet valve assembly 161 may include an LP fluid valve 167 disposed at a corresponding LP fluid outlet port 166 for selectively opening and closing the corresponding LP fluid outlet port 166, such as may selectively permit fluid flow out of the second LP manifold 144. Each LP fluid valve 163, 167 may be selectively transitioned between open flow and closed flow settings by a corresponding actuator 164, 168, respectively, disposed in association with each LP fluid valve 163, 167. The actual setting of each LP fluid valve 163, 167 may be determined in real-time by feedback sensors 165, 169, respectively, disposed in association with each LP fluid valve 163, 167. For clarity, just one of the LP ports 162, 166, the LP fluid valves 163, 167, the actuators 164, 168, and the feedback sensors 165, 169 of the LP inlet and outlet valve assemblies 160, 161, respectively, are identified with numerals in FIG. 2. Although the second LP manifold 144 is shown comprising four LP inlet valve assemblies 160 and eight LP

outlet valve assemblies 161, it is to be understood that the second LP manifold 144 may include other quantities of LP inlet and outlet valve assemblies 160, 161.

[0039] The manifold unit 140 may also comprise an HP portion or manifold 146 implemented as a fluid conduit arranged in a closed loop configuration. The HP manifold 146 may comprise a plurality of HP inlet valve assemblies 170 disposed on opposing sides of the HP manifold 146, each comprising an HP fluid inlet port 172 operable to fluidly connect the pumps 202 with the HP manifold 146 via corresponding HP fluid conduits 138. The HP manifold 146 may also comprise a plurality of HP outlet valve assemblies 171, each comprising an HP outlet port 176 operable to fluidly connect with the one or more fluid conduits 131 to inject the fluid into the wellbore 104. Each HP inlet valve assembly 170 may further include an HP fluid valve 173 disposed at a corresponding HP fluid inlet port 172 for selectively opening and closing the corresponding HP fluid inlet port 172, such as may selectively permit or otherwise control fluid flow into the HP manifold 146. Similarly, each HP outlet valve assembly 171 may include an HP fluid valve 177 disposed at a corresponding HP fluid outlet port 176 for selectively opening and closing the corresponding HP fluid outlet port 176, such as may selectively permit fluid flow out of the HP manifold 146. Each HP fluid valve 173, 177 may be selectively transitioned between open flow and closed flow settings by a corresponding actuator 174, 178, respectively, disposed in association with each HP fluid valve 173, 177. The actual setting of each HP fluid valve 173, 177 may be determined in real-time by feedback sensors 175, 179, respectively, associated with the HP fluid valves 173, 177. For clarity, just one of the HP ports 172, 176, the HP fluid valves 173, 177, the actuators 174, 178, and the feedback sensors 175, 179 of the HP inlet and outlet valve assemblies 170, 171, respectively, are identified with numerals in FIG. 2. Although the HP manifold 146 is shown comprising eight HP inlet valve assemblies 170 and four HP outlet valve assemblies 171, it is to be understood that the HP manifold 146 may include other quantities of HP inlet and outlet valve assemblies 170, 171.

[0040] Each HP fluid inlet port 172 of the HP manifold 146 may be fluidly connected with a corresponding bleed valve assembly 180 operable to release fluid and pressure from the HP fluid inlet port 172 and, perhaps, portions of the pump unit 200 in fluid communication with the corresponding HP fluid conduit 138. If a corresponding HP fluid valve 173 is open, the bleed valve assembly 180 may also bleed fluid and pressure from the HP manifold 146. Each bleed valve assembly 180 may comprise a bleed port 182 and a corresponding fluid bleed valve 183 disposed at the bleed port 182 for selectively opening and closing the bleed port 182, such as to

selectively permit or otherwise control fluid flow out of a corresponding HP fluid inlet port 172. Each fluid bleed valve 183 may be selectively transitioned between open flow and closed flow settings by a corresponding actuator 184 disposed in association with each fluid bleed valve 183. The actual setting of each fluid bleed valve 183 may be determined in real-time by a corresponding feedback sensor 185 associated with each fluid bleed valve 183. The fluid bled or released by the bleed valve assemblies 180 via corresponding bleed ports 182 may be communicated to a fluid container (not shown). The fluid container may be or comprise an external fluid container, such as a fluid pit or another container that may be constructed on or transported to the wellsite surface 102, in which case the bleed ports 182 may be fluidly connected with the fluid container. The fluid container may also be or comprise the first and/or second LP manifolds 142, 144, in which case the bleed ports 182 may be fluidly connected with the LP fluid inlet ports 152, 162. For clarity, just one of the bleed ports 182, the fluid bleed valves 183, the actuators 184, and the feedback sensors 185 of the bleed valve assemblies 180 are identified with numerals in FIG. 2.

[0041] Although shown in FIG. 2 as single continuous members, one or more of the manifolds 142, 144, 146 may comprise a plurality of fluid conduits or other fluid conveying members connected together to collectively form the manifold unit 140. The plurality of the fluid conduits may be fixedly connected together via threaded means, fasteners, bolts, flanges, welding, and/or other connection means. Furthermore, although shown as comprising a closed loop configuration, one or more of the manifolds 142, 144, 146 may comprise otherwise shaped open or closed loop or configurations, including a U-shaped configuration, a T-shaped configuration, an I-shaped configuration, or other configurations operable to communicate the fluid from the LP and HP fluid inlet ports 152, 162, 172 to the LP and HP fluid outlet ports 156, 166, 176. Although FIG. 2 depicts the manifolds 142, 144, 146 as being progressively larger, it is to be understood that FIG. 2 is a schematic representation and that the manifolds 142, 144, 146 may be the same size or may have other relative dimensions.

[0042] A fluid power unit 190 may provide pressurized fluid to operate the actuators 154, 158, 164, 168, 174, 178, 184. For example the fluid power unit 190 may comprise an air and/or compressor in implementations in which the actuators 154, 158, 164, 168, 174, 178, 184 are operable by pressurized air and/or other gas. However, the fluid power unit 190 may comprise a hydraulic power pack in implementations in which the actuators 154, 158, 164, 168, 174, 178, 184 are operable by pressurized hydraulic fluid. The fluid power unit 190 may comprise a fluid

storage container 191, such as an air tank or a hydraulic fluid tank, and a prime mover 192, such as an electric motor, a hydraulic motor, or an engine for pressurizing the fluid. Fluid interconnections between the fluid power unit 190 and the actuators 154, 158, 164, 168, 174, 178, 184 may be via various piping, hoses, and/or other fluid conduits. However, for the sake of clarity and ease of understanding, such interconnections are not depicted in FIG. 2, as a person having ordinary skill in the art will readily recognize how such interconnections may be implemented within the scope of the present disclosure without further illustration in FIG. 2.

[0043] The manifold unit 140 may also comprise pressure sensors 186, 187, 188 fluidly connected with the manifold unit 140. The pressure sensors 186, 187, 188 may be operable to generate signals or information indicative of the fluid pressure within the LP and HP manifolds 142, 144, 146, respectively.

[0044] FIG. 3 is a perspective view of a portion of an example implementation of one pump unit 200 shown in FIG. 1 according to one or more aspects of the present disclosure. FIG. 4 is a side sectional view of a portion of the pump unit 200 shown in FIG. 3. The following description refers to FIGS. 1-4, collectively.

[0045] As described above, the pump unit 200 comprises the pump 202 operatively coupled with and actuated by the prime mover 204. The pump 202 comprises a power section 208 and a fluid section 210. The fluid section 210 may comprise a pump housing 216 having a plurality of fluid chambers 218. One end of each fluid chamber 218 may be plugged by a cover plate 220, such as may be threadedly engaged with the pump housing 216 while the opposite end of each fluid chamber 218 may contain a reciprocating member 222 slidably disposed therein and operable to displace the fluid within the corresponding fluid chamber 218. Although the reciprocating member 222 is depicted as a plunger, the reciprocating member 222 may also be implemented as a piston, diaphragm, or another reciprocating fluid displacing member.

[0046] Each fluid chamber 218 is fluidly connected with a corresponding one of a plurality of fluid inlet cavities 224 each adapted for communicating fluid from an LP fluid inlet conduit 226 into a corresponding fluid chamber 218. The LP fluid inlet conduit 226 may be in fluid communication with a corresponding LP fluid outlet port 156, 166 of the manifold 140 via the one or more LP fluid conduits 136. Each fluid inlet cavity 224 contains an inlet valve 228 operable to control fluid flow from the LP fluid inlet conduit 226 into the fluid chamber 218. Each inlet valve 228 may be biased toward a closed flow setting by a first spring or another biasing member 230, which may be held in place by an inlet valve stop 232. Each inlet valve

228 may be actuated to an open flow setting by a selected or predetermined differential pressure between the corresponding fluid inlet cavity 224 and the LP fluid inlet conduit 226.

[0047] Each fluid chamber 218 is also fluidly connected with a fluid outlet cavity 234 extending through the pump housing 216 transverse to the reciprocating members 222. The fluid outlet cavity 234 is adapted for communicating pressurized fluid from each fluid chamber 218 into one or more HP fluid outlet conduits 235 fluidly connected at one or both ends of the fluid outlet cavity 234. The HP fluid outlet conduits 235 may be in fluid communication with a corresponding HP fluid inlet port 172 of the manifold 140 via the one or more HP fluid conduits 138. The fluid section 210 also contains a plurality of outlet valves 236 each operable to control fluid flow from a corresponding fluid chamber 218 into the fluid outlet cavity 234. Each outlet valve 236 may be biased toward a closed flow setting by a spring or another biasing member 238, which may be held in place by an outlet valve stop 240. Each outlet valve 236 may be actuated to an open flow setting by a selected or predetermined differential pressure between the corresponding fluid chamber 218 and the fluid outlet cavity 234. The fluid outlet cavity 234 may be plugged by cover plates 242, such as may be threadedly engaged with the pump housing 216.

[0048] During pumping operations, portions of the power section 208 of the pump unit 200 rotate in a manner that generates a reciprocating linear motion to move the reciprocating members 222 longitudinally within the corresponding fluid chambers 218, thereby alternatingly drawing and displacing the fluid within the fluid chambers 218. With regard to each reciprocating member 222, as the reciprocating member 222 moves out of the fluid chamber 218, as indicated by arrow 221, the pressure of the fluid inside the corresponding fluid chamber 218 decreases, thus creating a differential pressure across the corresponding fluid inlet valve 228. The pressure differential operates to compress the biasing member 230, thus actuating the fluid inlet valve 228 to an open flow setting to permit the fluid from the LP fluid inlet conduit 226 to enter the corresponding fluid inlet cavity 224. The fluid then enters the fluid chamber 218 as the reciprocating member 222 continues to move longitudinally out of the fluid chamber 218 until the pressure difference between the fluid inside the fluid chamber 218 and the fluid within the LP fluid inlet conduit 226 is low enough to permit the biasing member 230 to actuate the fluid inlet valve 228 to the closed flow setting. As the reciprocating member 222 begins to move longitudinally back into the fluid chamber 218, as indicated by arrow 223, the pressure of the fluid inside of fluid chamber 218 begins to increase. The fluid pressure inside the fluid chamber 218 continues to increase as the reciprocating member 222 continues to move into the fluid

chamber 218 until the pressure of the fluid inside the fluid chamber 218 is high enough to overcome the pressure of the fluid inside the fluid outlet cavity 234 and compress the biasing member 238, thus actuating the fluid outlet valve 236 to the open flow setting and permitting the pressurized fluid to move into the fluid outlet cavity 234 and the HP fluid outlet conduit 235. Thereafter, the fluid may be communicated to the manifold 140 via the one or more HP fluid conduits 138 and the wellbore 104 via the one or more fluid conduits 131.

[0049] The fluid flow rate generated by the pump unit 200 may depend on the physical size of the reciprocating members 222 and fluid chambers 218, as well as the pump operating speed, which may be defined by the speed or rate at which the reciprocating members 222 cycle or move within the fluid chambers 218. The speed or rate at which the reciprocating members 222 move may be related to the rotational speed of the power section 208 and/or the prime mover 204. Accordingly, the fluid flow rate may be controlled by controlling the rotational speed of the power section 208 and/or the prime mover.

[0050] The prime mover 204 may be operatively coupled with a drive shaft 252 of the power section 208. The drive shaft 252 may be enclosed and maintained in position by a power section housing 254, such that the prime mover 204 is operable to drive or otherwise rotate the drive shaft 252. The prime mover 204 may comprise a rotatable output shaft 256 operatively connected with the drive shaft 252 by a transmission or gear train, which may comprise at least one spur gear 258 coupled with the drive shaft 252 and at least one pinion gear 260 coupled with a support shaft 261. The output shaft 256 and the support shaft 261 may be coupled, such as may facilitate transfer of torque from the prime mover 204 to the support shaft 261, the pinion gear 260, the spur gear 258, and the drive shaft 252. For clarity, FIGS. 3 and 4 show the transmission comprising a single spur gear 258 engaging a single pinion gear 260, however, it is to be understood that the transmission may comprise two or more sets of gears, such as may permit the transmission to be shifted between different gear configurations to control the operating speed of the drive shaft 252 and, thus, the pumping rate of the fluid section 210. To prevent relative rotation between the power section housing 254 and the prime mover 204, the power section housing 254 and prime mover 204 may be fixedly coupled together or to a common base, such as a trailer of the mobile carrier 148. The prime mover 204 may comprise an engine, such as a gasoline engine or a diesel engine, an electric motor, such as a synchronous or asynchronous electric motor, including a synchronous permanent magnet motor, a hydraulic motor, or another prime mover operable to rotate the drive shaft 252.

[0051] The drive shaft 252 may be implemented as a crankshaft comprising a plurality of axial journals 264 and offset journals 266. The axial journals 264 may extend along a central axis of rotation of the drive shaft 252, while the offset journals 266 may be offset from the central axis of rotation by a selected or predetermined distance and spaced 120 degrees apart with respect to the axial journals 264. The drive shaft 252 may be supported in position within the power section 208 by the power section housing 254, wherein two of the axial journals 264 may extend through opposing openings in the power section housing 254.

[0052] The power section 208 and the fluid section 210 may be coupled or otherwise connected together. For example, the pump housing 216 may be fastened with the power section housing 254 by a plurality of threaded fasteners 282. The pump 202 may further comprise an access door 298, which may facilitate access to portions of the pump 202 located between the power section 208 and the fluid section 210, such as during assembly and/or maintenance of the pump 202.

[0053] To transform and transmit the rotational motion of the drive shaft 252 to a reciprocating linear motion of the reciprocating members 222, a plurality of crosshead mechanisms 285 may be utilized. For example, each crosshead mechanism 285 may comprise a connecting rod 286 pivotally coupled with a corresponding offset journal 266 at one end and with a pin 288 of a crosshead 290 at an opposing end. During pumping operations, walls and/or interior portions of the power section housing 254 may guide each crosshead 290, such as may reduce or eliminate lateral motion of each crosshead 290. Each crosshead mechanism 285 may further comprise a piston rod 292 coupling the crosshead 290 with the reciprocating member 222. The piston rod 292 may be coupled with the crosshead 290 via a threaded connection 294 and with the reciprocating member 222 via a flexible connection 296.

[0054] Although FIGS. 3 and 4 show the pump unit 200 comprising a triplex reciprocating pump 202, which has three fluid chambers 218 and three reciprocating members 222, implementations within the scope of the present disclosure may include the pump 202 as or comprising a quintuplex reciprocating pump having five fluid chambers 218 and five reciprocating members 222, or a pump having other quantities of fluid chambers 218 and reciprocating members 222. It is further noted that the pump 202 described above and shown in FIGS. 3 and 4 is merely an example, and that other pumps, such as diaphragm pumps, gear pumps, external circumferential pumps, internal circumferential pumps, lobe pumps, and other positive displacement pumps, are also within the scope of the present disclosure.

[0055] The wellsite system 100 may further comprise flow sensors disposed in association with the pumps 202, the manifold unit 140, and/or the LP and HP fluid conduits 136, 138 in a manner permitting the sensing of fluid flow generated by the pumps 202. Each flow sensor is operable to generate an electrical signal and/or information indicative of the rate of fluid flow from a corresponding pump 202 to the manifold unit 140. For example, flow sensors 304 may be fluidly coupled along the HP fluid outlet conduits 235 of the pumps 202, as shown in FIG. 3. The flow sensors 304 may also be fluidly coupled along the HP fluid conduits 138 extending between the HP fluid outlet conduits 235 and the HP fluid inlet ports 172 of the manifold unit 140. The flow sensors 304 may also be disposed in association with the manifold unit 140. For example, the flow sensors 304 may be fluidly coupled with the HP fluid inlet ports 172.

[0056] The wellsite system 100 may further comprise pressure sensors disposed in association with the pumps 202, the manifold unit 140, and/or the LP and HP fluid conduits 136, 138 in a manner permitting the sensing of fluid pressure within the pumps 202, the manifold unit 140, and/or the LP and HP fluid conduits 136, 138. Each pressure sensor is may be operable to generate an electrical signal and/or information indicative of the fluid pressure within the pumps 202, the manifold unit 140, and/or the LP and HP fluid conduits 136, 138. For example, one or more pressure sensors 306 may extend through one or more of the cover plates 242 or other portions of the corresponding pump housing 216 to monitor pressure within the fluid outlet cavity 234 and, thus, the HP fluid outlet conduits 235 and the HP fluid conduits 138. The pressure sensors 306 may also be fluidly coupled along the HP fluid outlet conduits 235 and/or along the HP fluid conduits 138. Other pressure sensors, such as the pressure sensors 186, 187, 188 shown in FIG. 2, may be disposed in association with the manifold unit 140 to monitor the pressure within the manifolds 142, 144, 146.

[0057] The wellsite system 100 may further comprise a controller 310 in communication with the valve actuators 154, 158, 164, 168, 174, 178, 184 to permit the controller 310 to open and close or otherwise control the fluid valves 153, 157, 163, 167, 173, 177, 183. The controller 310 is further in communication with the valve feedback sensors 155, 159, 165, 169, 175, 179, 185 to permit the controller 310 to receive the feedback signals generated by the feedback sensors 155, 159, 165, 169, 175, 179, 185 and, thus, verify that the fluid valves 153, 157, 163, 167, 173, 177, 183 transitioned to the intended position or setting. The controller 310 is also in communication with the prime movers 204 and/or other portions of the pump units 200, such as may permit the controller 310 to activate, deactivate, shift transmission gears or speeds, or

otherwise operate the pump units 200. The controller 310 is also in communication with the pressure sensors 186, 187, 188 associated with the manifold unit 140 and the pressure and flow sensors 306, 304 associated with each pump 202 or HP fluid conduit 138, such as may permit the controller 310 to receive the information indicative of fluid pressure and flow within the pumps 202, the HP fluid conduits 138, and/or the manifold 140. For clarity, the components in communication with the controller 310 will be collectively referred to hereinafter as "feedback and controlled components." Communication between the controller 310 and the feedback and controlled components may be via wired and/or wireless communication means. However, for clarity and ease of understanding, such communication means are not depicted in FIGS. 1-4, and a person having ordinary skill in the art will appreciate that myriad means for such communication means are within the scope of the present disclosure. The controller 310 may be implemented as part of the control/power center 133, or as a discrete component located externally from the control/power center 133.

[0058] FIG. 5 is a schematic view of at least a portion of an example implementation of the controller 310 according to one or more aspects of the present disclosure. The controller 310 may be operable to execute example machine-readable instructions to implement at least a portion of one or more of the example methods and/or processes described herein, and/or to implement at least a portion of one or more of the example systems described herein. The controller 310 may be or comprise, for example, one or more processors, special-purpose computing devices, servers, personal computers, personal digital assistant (PDA) devices, smartphones, internet appliances, and/or other types of computing devices.

[0059] The controller 310 may comprise a processor 312, such as a general-purpose programmable processor. The processor 312 may comprise a local memory 314, and may execute coded instructions 332 present in the local memory 314 and/or another memory device. The processor 312 may execute, among other things, machine-readable instructions or programs to implement the example methods and/or processes described herein. The programs stored in the local memory 314 may include program instructions or computer program code that, when executed by an associated processor, facilitate the pump units 200 and the manifold unit 140 to perform the example methods and/or processes described herein. The processor 312 may be, comprise, or be implemented by one or a plurality of processors of various types suitable to the local application environment, and may include one or more of general-purpose computers, special-purpose computers, microprocessors, digital signal processors (DSPs), field-

programmable gate arrays (FPGAs), application-specific integrated circuits (ASICs), and processors based on a multi-core processor architecture, as non-limiting examples. Of course, other processors from other families are also appropriate.

[0060] The processor 312 may be in communication with a main memory, such as may include a volatile memory 318 and a non-volatile memory 320, perhaps via a bus 322 and/or other communication means. The volatile memory 318 may be, comprise, or be implemented by random access memory (RAM), static random access memory (SRAM), synchronous dynamic random access memory (SDRAM), dynamic random access memory (DRAM), RAMBUS dynamic random access memory (RDRAM), and/or other types of random access memory devices. The non-volatile memory 320 may be, comprise, or be implemented by read-only memory, flash memory, and/or other types of memory devices. One or more memory controllers (not shown) may control access to the volatile memory 318 and/or non-volatile memory 320. The controller 310 may be operable to store or record information entered by the human operators and/or information generated by the feedback and controlled components on the main memory.

[0061] The controller 310 may also comprise an interface circuit 324. The interface circuit 324 may be, comprise, or be implemented by various types of standard interfaces, such as an Ethernet interface, a universal serial bus (USB), a third generation input/output (3GIO) interface, a wireless interface, and/or a cellular interface, among others. The interface circuit 324 may also comprise a graphics driver card. The interface circuit 324 may also comprise a communication device, such as a modem or network interface card to facilitate exchange of data with external computing devices via a network (*e.g.*, Ethernet connection, digital subscriber line (DSL), telephone line, coaxial cable, cellular telephone system, satellite, *etc.*). One or more of the feedback and controlled components may be connected with the controller 310 via the interface circuit 324, such as may facilitate communication between the feedback and controlled components and the controller 310.

[0062] To further facilitate communication between the manifold unit components and the controller 310, one or more of the feedback and controlled components may also comprise an interface circuit (not shown), which may permit signals or information generated by the feedback and controlled components to be sent to the controller 310 for monitoring and/or controlling operation of the one or more of the feedback and controlled components, or perhaps for monitoring and/or controlling operation of the entirety of the manifold unit 140. The interface

circuits of the one or more of the feedback and controlled components may also permit signals to be received from the controller 310 to control operation of the one or more of the feedback and controlled components, or perhaps to control operation of the entirety of the manifold unit 140.

[0063] One or more input devices 326 may also be connected to the interface circuit 324. The input devices 326 may permit the human operators to enter the coded instructions 332, operational parameter thresholds, and/or other data into the processor 312. The input devices 326 may be, comprise, or be implemented by a keyboard, a mouse, a touchscreen, a track-pad, a trackball, an isopoint, and/or a voice recognition system, among other examples. One or more output devices 328 may also be connected to the interface circuit 324. The output devices 328 may be, comprise, or be implemented by display devices (*e.g.*, a liquid crystal display (LCD) or cathode ray tube display (CRT), among others), printers, and/or speakers, among other examples. The controller 310 may also connect with one or more mass storage devices 330 and/or a removable storage medium 334, such as may be or include floppy disk drives, hard drive disks, compact disk (CD) drives, digital versatile disk (DVD) drives, and/or USB and/or other flash drives, among other examples.

[0064] The coded instructions 332, the operational parameter thresholds, and/or other data may be stored in the mass storage device 330, the volatile memory 318, the non-volatile memory 320, the local memory 314, and/or the removable storage medium 334. Thus, components of the controller 310 may be implemented in accordance with hardware (perhaps implemented in one or more chips including an integrated circuit, such as an application specific integrated circuit), or may be implemented as software or firmware for execution by the processor 312. In the case of firmware or software, the implementation may be provided as a computer program product including a computer readable medium or storage structure embodying computer program code (*i.e.*, software or firmware) thereon for execution by the processor 312.

[0065] The coded instructions 332 may include program instructions or computer program code that, when executed by the processor 312, may cause the wellsite system 100 (or at least components thereof) to perform methods and processes as described herein. For example, the controller 310 may cause the pump units 200, the manifold unit 140, and the feedback and controlled components to conduct and/or undergo depressurizing and flushing operations, such as to permit the pump units 200 and the manifold unit 140 to be safely fluidly disconnected. The controller 310 may also assess operational health of the fluid valves 153, 157, 163, 167, 173,

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177, 183 and/or the sensors 186, 187, 188, 304, 306 before and/or after the depressurizing and flushing operations or other pumping operations.

[0066] The operational parameter thresholds may be entered into the controller 310 by the human operators to be processed by the processor 312 prior to or during the depressurizing and flushing operations. The operational parameter thresholds may include a predetermined fluid pressure threshold (hereinafter referred to as the "pressure threshold"). When the fluid pressure within the HP fluid conduit 138 and perhaps portions of the pump unit 200 and the manifold unit 140 in fluid communication with the HP fluid conduit 138 is greater than the pressure threshold, the HP fluid conduit 138 and portions of the pump unit 200 and the manifold unit 140 in fluid communication with the HP fluid conduit 138 may be considered to be pressurized or under pressure. However, when the fluid pressure within the HP fluid conduit 138 and portions of the pump unit 200 and the manifold unit 140 in fluid communication with the HP fluid conduit 138 is less than the pressure threshold, the HP fluid conduit 138 and portions of the pump unit 200 and the manifold unit 140 in fluid communication with the HP fluid conduit 138 may be considered to be substantially depressurized or not under pressure. When the HP fluid conduit 138 and portions of the pump unit 200 and the manifold unit 140 in fluid communication with the HP fluid conduits 138 are not under pressure, the pump unit 200 may be caused to cease operation and the pump unit 200 may be fluidly uncoupled from the manifold 140. In an example implementation, the pressure threshold may include a fluid pressure ranging between about zero PSI and about fifteen PSI.

[0067] Another operational parameter threshold may include a predetermined fluid flow rate threshold (hereinafter referred to as the "flow threshold"). When a fluid flow rate between the pump units 200 and the manifold unit 140 through the corresponding HP fluid conduits 138 is greater than the flow threshold, the HP fluid conduit 138 and perhaps portions of the pump unit 200 in fluid communication with the HP fluid conduit 138 may be considered containing fluid or not flushed. However, when the fluid flow rate between the pump unit 200 and the manifold unit 140 through the corresponding HP fluid conduit 138 is less than the flow threshold, the HP fluid conduit 138 and portions of the pump unit 200 in fluid communication with the HP fluid conduit 138 may be considered substantially free of fluid or flushed. When the HP fluid conduit 138 and portions of the pump unit 200 in fluid communication with the HP fluid conduit 138 are substantially flushed, the pump unit 200 may be caused to cease operation and the pump unit 200 may be fluidly uncoupled from the manifold 140. In an example implementation, the flow

threshold may include a fluid flow rate ranging between about zero GPM and about one GPM. Accordingly, the coded instructions 332, when executed, may further cause the controller 310 to receive and process the pressure and flow thresholds entered by the human operators.

[0068] To depressurize an HP fluid conduit 138 and portions of a pump units 200 and the manifold unit 140 in fluid communication with the HP fluid conduit 138, the controller 310 may cause the pump unit 200 to operate and then cause the LP fluid valves 157, 167 corresponding to the pump unit 200 to transition to the closed flow position and cause the HP fluid valve 173 corresponding to the pump unit 200 and/or the fluid bleed valve 183 corresponding to the pump unit 200 to transition to the open flow position. Afterwards, the controller 310 may determine that the HP fluid conduit 138 corresponding to the pump unit 200 is not pressurized based on the information generated by the corresponding one of the pressure sensors 188, 306. The controller 310 may be operable to determine whether the HP fluid conduit 138 corresponding to the pump unit 200 is not pressurized by comparing the pressure threshold to the fluid pressure indicated by the information generated by a corresponding pressure sensor 188, 306.

[0069] The controller 310 may also determine whether the HP fluid conduit 138 corresponding to the pump unit 200 and portions of the pump unit 200 in fluid communication with the HP fluid conduit 138 is substantially flushed based on the information generated by a corresponding one of the flow sensors 304. The controller 310 may be operable to determine whether the HP fluid conduit 138 corresponding to the pump unit 200 is substantially flushed by comparing the flow threshold to the fluid flow rate indicated by the information generated by the corresponding one of the flow sensors 304, wherein the HP fluid conduit 138 is considered substantially flushed when the flow threshold is greater than the fluid flow rate indicated by the information generated by the corresponding one of the flow sensors 304.

[0070] Before the pump units 200 are activated, the human operators may perform several safety and operational health assessments. For example, the human operators may visually check that no other human operators are present near the pump units 200 and the manifold unit 140. The human operators may also visually inspect the LP and HP fluid conduits 136, 138 and other associated fluid conduits and/or couplings to check for leaks and physical damage. The human operators may also visually and/or manually asses if the various sensors and fluid valves associated with the pump units 200 and the manifold unit 140 are functioning properly. For example, the human operators may check if the pressure sensors 186, 187, 188, 306, the flow sensors 304, and the fluid valves 153, 157, 163, 167, 173, 177, 183 are operationally healthy. If

one or more of these safety and operational health assessments identify a safety or functionality problem, the human operators may abort the depressurizing and flushing operations before the pump units 200 are activated.

[0071] Instead of or in addition to the human operators performing the safety and operational health assessments, the coded instructions 332, when executed, may further cause the controller 310 to assess safety conditions and functionality or operational health of the sensors 186, 187, 188, 304, 306 and/or the fluid valves 153, 157, 163, 167, 173, 177, 183. For example, the controller 310 may be operable to transmit diagnostic signals to one or more of the pressure sensors 186, 187, 188, 306, the flow sensors 304, and the fluid valves 153, 157, 163, 167, 173, 177, 183 and receive corresponding feedback signals indicative of the operational health of these components.

[0072] To assess the operational health of the fluid valves 153, 157, 163, 167, 173, 177, 183, before and/or after the depressurizing and flushing operations, the controller 310 may be operable to, with respect to each of the fluid valves 153, 157, 163, 167, 173, 177, 183, remotely control the fluid valve 153, 157, 163, 167, 173, 177, 183 by transmitting a command signal to the fluid valve 153, 157, 163, 167, 173, 177, 183 to transition the fluid valve 153, 157, 163, 167, 173, 177, 183 from an existing setting to an intended setting. After transmitting the command signal, the controller 310 may receive a feedback signal from the fluid valves 153, 157, 163, 167, 173, 177, 183 indicative of an actual setting of the fluid valve 153, 157, 163, 167, 173, 177, 183 and assess an operational health of the fluid valve 153, 157, 163, 167, 173, 177, 183 based on the intended and actual settings. If the intended and actual settings are different, than the fluid valves 153, 157, 163, 167, 173, 177, 183 may be determined to be faulty or not healthy. To further verify if the fluid valves 153, 157, 163, 167, 173, 177, 183 are healthy, the fluid valves 153, 157, 163, 167, 173, 177, 183 may be transitioned and reassessed additional number of times.

[0073] The operational health of the fluid valves 153, 157, 163, 167, 173, 177, 183 may be assessed simultaneously, wherein the controller 310 simultaneously transmits the command signals to the fluid valves 153, 157, 163, 167, 173, 177, 183, and assesses the operational health of the fluid valves 153, 157, 163, 167, 173, 177, 183 based on the intended and actual settings. The operational health of the fluid valves 153, 157, 163, 167, 173, 177, 183 may also be checked sequentially, wherein the controller 310 transmits the command signals to each of the fluid valves 153, 157, 163, 167, 173, 177, 183 one at a time, and assesses the operational health of one

of the fluid valves 153, 157, 163, 167, 173, 177, 183 based on the intended and actual settings before transmitting a command signal to another one of the fluid valves 153, 157, 163, 167, 173, 177, 183.

[0074] If the controller 310 determines that one or more of the sensors 186, 187, 188, 306 and fluid valves 153, 157, 163, 167, 173, 177, 183 are not healthy, the controller 310 may abort the depressurizing and flushing operations before activating the pump units 200.

[0075] FIG. 6 is a flow-chart diagram of at least a portion of an example implementation of a method (400) according to one or more aspects of the present disclosure. The method (400) may be performed utilizing at least a portion of one or more implementations of the apparatus shown in one or more of FIGS. 1-5 and/or otherwise within the scope of the present disclosure.

[0076] The method (400) comprises establishing (410) communication between the controller 310 and each of the plurality of valves 153, 157, 163, 167, 173, 177, 183 of a manifold unit 140, wherein each of the valves 153, 157, 163, 167, 173, 177, 183 is operable to control flow through a corresponding one of a plurality of ports 152, 156, 162, 166, 172, 176, 182 of the manifold unit 140. The method (400) further comprises operating (420) the controller 310, with respect to each of the valves 153, 157, 163, 167, 173, 177, 183, to remotely control (430) the valve 153, 157, 163, 167, 173, 177, 183 by transmitting a command signal to the valve 153, 157, 163, 167, 173, 177, 183 to transition the valve 153, 157, 163, 167, 173, 177, 183 from an existing setting to an intended setting, after transmitting the command signal, receive (440) a feedback signal from the valve 153, 157, 163, 167, 173, 177, 183 indicative of an actual setting of the valve 153, 157, 163, 167, 173, 177, 183, and assess (450) an operational health of the valve based on the intended and actual settings.

[0077] The operating (430), receiving (440), and assessing (450) may be repeated additional times for each valve 153, 157, 163, 167, 173, 177, 183, such that the command signal is a first command signal, the feedback signal is a first feedback signal, the intended setting is a first intended setting, and the actual setting is a first actual setting. Accordingly, the method (400) may further comprise operating the controller 310 to, with respect to each of the valves 153, 157, 163, 167, 173, 177, 183, further remotely control the valve 153, 157, 163, 167, 173, 177, 183 by transmitting a second command signal to the valve 153, 157, 163, 167, 173, 177, 183 to transition the valve 153, 157, 163, 167, 173, 177, 183 to a second intended setting. After transmitting the second command signal, the controller 310 may receive a second feedback signal from the valve 153, 157, 163, 167, 173, 177, 183 indicative of a second actual setting of

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the valve and reassess the operational health of the valve 153, 157, 163, 167, 173, 177, 183 based on the second intended setting and the second actual setting. The first intended setting may be a closed flow setting and the second intended setting may be an open flow setting.

[0078] The method (400) may also comprise operating the controller 310 to, with respect to each of the valves 153, 157, 163, 167, 173, 177, 183, remotely control the valve 153, 157, 163, 167, 173, 177, 183 by transmitting a third command signal to the valve 153, 157, 163, 167, 173, 177, 183 to transition the valve 153, 157, 163, 167, 173, 177, 183 to a third intended setting. After transmitting the third command signal, the controller 310 may receive a third feedback signal from the valve 153, 157, 163, 167, 173, 177, 183 indicative of a third actual setting of the valve 153, 157, 163, 167, 173, 177, 183, and reassess the operational health of the valve 153, 157, 163, 167, 173, 177, 183 based on the third intended setting and the third actual setting. The third intended setting may be a closed flow setting.

[0079] The method (400) may also include operating the controller 310 with respect to each of the valves 153, 157, 163, 167, 173, 177, 183 one at a time. The plurality of valves 153, 157, 163, 167, 173, 177, 183 may comprise a first valve, a second valve, and a third valve. Accordingly, operating the controller 310 may include remotely controlling the first valve by transmitting a first command signal to the first valve to transition the first valve to a first intended setting, then receiving a first feedback signal from the first valve indicative of a first actual setting of the first valve, and then assessing a first operational health of the first valve based on the first intended setting and the first actual setting. The method may further include, after assessing the first operational health, remotely controlling the second valve by transmitting a second command signal to the second valve to transition the second valve to a second intended setting, then receiving a second feedback signal from the second valve indicative of a second actual setting of the second valve, and then assessing a second operational health of the second valve based on the second intended setting and the second actual setting. The method (400) may also include, after assessing the second operational health, remotely controlling the third valve by transmitting a third command signal to the third valve to transition the third valve to a third intended setting, then receiving a third feedback signal from the third valve indicative of a third actual setting of the third valve, and then assessing a third operational health of the third valve based on the third intended setting and the third actual setting.

[0080] FIG. 7 is a flow-chart diagram of at least a portion of a method (500) according to one or more aspects of the present disclosure. The method (500) may be performed utilizing at least

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a portion of one or more implementations of the apparatus shown in one or more of FIGS. 1-5 and/or otherwise within the scope of the present disclosure.

[0081] The method (500) may include providing (510) a plurality of pumps (200) and a manifold unit (140), fluidly coupling (520) each of the pumps (200) with the LP manifold 142, 144 via a plurality of LP conduits 136 each fluidly coupling (520) a corresponding one of the pumps (200) with a corresponding one of the LP ports 156, 166, and fluidly coupling (520) each of the pumps (200) with the HP manifold 146 via a plurality of HP conduits 138 each fluidly coupling a corresponding one of the pumps 200 with a corresponding one of the HP ports 172. The method (500) further comprises establishing (530) communication between a controller 310 and each of the LP valves 157, 167, the HP valves 173, the bleed valves 183, the pumps 200, and a plurality of sensors 188, 306 each operable to generate information indicative of fluid pressure within a corresponding one of the HP conduits 138. The method (500) further includes operating (540) the controller 310 to, with respect to each of the pumps 200, cause (542) the pump 200 to operate and then cause (544) the LP valves 157, 167 corresponding to the pump 200 to transition to a closed flow position and cause (546) one of the HP valve 173 corresponding to the pump 200 and the bleed valve 183 corresponding to the pump 200 to transition to an open flow position. The controller 310 may also be utilized to determine (548) that the HP conduit 138 corresponding to the pump 200 is not pressurized based on the information generated by the corresponding one of the sensors 188, 306. With respect to each of the pumps 200, after the controller 310 determines that the HP conduit 138 corresponding to the pump 200 is not pressurized, the pump 200 may be fluidly uncoupled (550) from the manifold unit 140.

[0082] The method (500) may also comprise, prior to transitioning (544, 546) the LP valves 157, 167, the HP valve 173, and the bleed valve 183, operating the controller 310 to, with respect to each of the pumps 200, confirm that the LP valve 157, 167 corresponding to the pump 200 is in the closed flow position and confirm that the one of the HP valve 173 corresponding to the pump 200 and the bleed valve 183 corresponding to the pump 200 is in the open flow position.

[0083] The method (500) may further comprise, prior to causing (542) the pump 200 to operate and/or after causing the pump 200 to cease to operate, operating the controller 310 to, with respect to each of the pumps 200, remotely control the LP, HP, and bleed valves 157, 167, 173, 183 corresponding to the pump 200 by transmitting corresponding command signals to the LP, HP, and bleed valves 157, 167, 173, 183 to transition the LP, HP, and bleed valves 157, 167, 173, 183 from corresponding existing settings to corresponding intended settings. After

transmitting the command signals, the controller 310 may receive corresponding feedback signals from the LP, HP, and bleed valves 157, 167, 173, 183 corresponding to the pump 200, the feedback signals being indicative of corresponding actual settings of the LP, HP, and bleed valves 157, 167, 173, 183, such that the controller may be utilized to assess an operational health of each of the LP, HP, and bleed valves 157, 167, 173, 183 corresponding to the pump 200 based on the corresponding intended and actual settings.

[0084] After operating the controller 310 to cause the transition (544, 546) of the LP valves 157, 167 and the one of the HP and bleed valves 173, 183 corresponding to each of the pumps 200, the controller 310 may be operated to cause each of the pumps 200 to operate at an increased flow output, such as to increase fluid suction, fluid velocity, or otherwise increase the ability for the pump units 200 to expel the fluid from the HP fluid conduits 138 and, perhaps, portions of the pumps 202 in fluid communication with the HP fluid conduits 138.

[0085] The plurality of sensors 188, 306 may be pressure sensors 188, 306, and the method may further comprise establishing communication between the controller 310 and each of a plurality of flow sensors 304 operable to generate information indicative of rate of fluid flow within a corresponding one of the HP conduits 138. The controller 310 may thus also be utilized to, with respect to each of the pumps 200, determine whether the HP conduit 138 corresponding to the pump 200 is substantially flushed based on the information generated by the corresponding one of the flow sensors 304. The controller 310 may also be operated to, with respect to each of the pumps 200, cease operation of the pump 200 after the controller 310 determines that the HP conduit 138 corresponding to the pump 200 is substantially flushed.

[0086] In view of the entirety of the present disclosure, including the figures and the claims, a person having ordinary skill in the art will readily recognize that the present disclosure introduces an apparatus comprising: (a) a manifold unit comprising a plurality of ports and a plurality of valves, wherein each of the valves is operable to control flow through a corresponding one of the ports; and (b) a controller operable to, with respect to each of the valves: (1) remotely control the valve by transmitting a command signal to the valve to transition the valve from an existing setting to an intended setting; (2) after transmitting the command signal, receive a feedback signal from the valve indicative of an actual setting of the valve; and (3) assess an operational health of the valve based on the intended and actual settings.

[0087] The command signal may be a first command signal, the feedback signal may be a first feedback signal, the intended setting may be a first intended setting, the actual setting may

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be a first actual setting, and the controller may be further operable to, with respect to each of the valves: further remotely control the valve by transmitting a second command signal to the valve to transition the valve to a second intended setting; after transmitting the second command signal, receive a second feedback signal from the valve indicative of a second actual setting of the valve; and reassess the operational health of the valve based on the second intended setting and the second actual setting. The first intended setting may be a closed flow setting, and the second intended setting may be an open flow setting. The controller may be further operable to, with respect to each of the valves: further remotely control the valve by transmitting a third command signal to the valve to transition the valve to a third intended setting; after transmitting the third command signal, receive a third feedback signal from the valve indicative of a third actual setting of the valve; and reassess the operational health of the valve based on the third intended setting and the third actual setting. The third intended setting may be a closed flow setting.

[0088] The plurality of valves may comprise a first valve, a second valve, and a third valve, and the controller may be operable to: remotely control the first valve by transmitting a first command signal to the first valve to transition the first valve to a first intended setting, then receive a first feedback signal from the first valve indicative of a first actual setting of the first valve, and then assess a first operational health of the first valve based on the first intended setting and the first actual setting; after assessing the first operational health, remotely control the second valve by transmitting a second command signal to the second valve to transition the second valve to a second intended setting, then receive a second feedback signal from the second valve indicative of a second actual setting of the second valve, and then assess a second operational health of the second valve based on the second intended setting and the second actual setting; and after assessing the second operational health, remotely control the third valve by transmitting a third command signal to the third valve to transition the third valve to a third intended setting, then receive a third feedback signal from the third valve indicative of a third actual setting of the third valve, and then assess a third operational health of the third valve based on the third intended setting and the third actual setting.

[0089] The present disclosure also introduces a method comprising: (a) establishing communication between a controller and each of a plurality of valves of a manifold unit, wherein each of the valves is operable to control flow through a corresponding one of a plurality of ports of the manifold unit; and (b) operating the controller to, with respect to each of the valves: (1)

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remotely control the valve by transmitting a command signal to the valve to transition the valve from an existing setting to an intended setting; (2) after transmitting the command signal, receive a feedback signal from the valve indicative of an actual setting of the valve; and (3) assess an operational health of the valve based on the intended and actual settings.

[0090] The command signal may be a first command signal, the feedback signal may be a first feedback signal, the intended setting may be a first intended setting, the actual setting may be a first actual setting, and the method may further comprise operating the controller to, with respect to each of the valves: further remotely control the valve by transmitting a second command signal to the valve to transition the valve to a second intended setting; after transmitting the second command signal, receive a second feedback signal from the valve indicative of a second actual setting of the valve; and reassess the operational health of the valve based on the second intended setting and the second actual setting. The first intended setting may be a closed flow setting, and the second intended setting may be an open flow setting. The method may further comprise operating the controller to, with respect to each of the valves: further remotely control the valve by transmitting a third command signal to the valve to transition the valve to a third intended setting; after transmitting the third command signal, receive a third feedback signal from the valve indicative of a third actual setting of the valve; and reassess the operational health of the valve based on the third intended setting and the third actual setting. The third intended setting may be a closed flow setting.

[0091] The plurality of valves may comprise a first valve, a second valve, and a third valve, and operating the controller may include: remotely controlling the first valve by transmitting a first command signal to the first valve to transition the first valve to a first intended setting, then receiving a first feedback signal from the first valve indicative of a first actual setting of the first valve, and then assessing a first operational health of the first valve based on the first intended setting and the first actual setting; after assessing the first operational health, remotely controlling the second valve by transmitting a second command signal to the second valve to transition the second valve to a second intended setting, then receiving a second feedback signal from the second valve indicative of a second actual setting of the second valve, and then assessing a second operational health of the second valve based on the second intended setting and the second actual setting; and after assessing the second operational health, remotely controlling the third valve by transmitting a third command signal to the third valve to transition the third valve to a third intended setting, then receiving a third feedback signal from the third

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valve indicative of a third actual setting of the third valve, and then assessing a third operational health of the third valve based on the third intended setting and the third actual setting.

[0092] The present disclosure also introduces an apparatus comprising: (a) a manifold unit comprising: (1) a low-pressure (LP) manifold having a plurality of LP ports; (2) a plurality of LP valves each operable to control flow through a corresponding one of the LP ports; (3) a high-pressure (HP) manifold having a plurality of HP ports; (4) a plurality of HP valves each operable to control flow through a corresponding one of the HP ports; (5) a plurality of bleed ports each fluidly coupled with a corresponding one of the HP ports; and (6) a plurality of bleed valves each fluidly coupled with and remotely operable to control flow through a corresponding one of the bleed ports from the corresponding HP port; (b) a plurality of pumps; (c) a plurality of LP conduits each fluidly coupling a corresponding one of the pumps and a corresponding one of the LP ports; (d) a plurality of HP conduits each fluidly coupling a corresponding one of the pumps and a corresponding one of the HP ports; (e) a plurality of sensors each operable to generate information indicative of fluid pressure within a corresponding one of the HP conduits; and (f) a controller in communication with the LP valves, the HP valves, the bleed valves, the sensors, and the pumps, wherein the controller is operable to, with respect to each of the pumps: (1) cause the LP valve corresponding to the pump to transition to a closed flow position; (2) cause one of the HP valve corresponding to the pump and the bleed valve corresponding to the pump to transition to an open flow position; and (3) determine whether the HP conduit corresponding to the pump is pressurized based on the information generated by the corresponding one of the sensors.

[0093] With respect to each of the pumps, the controller may be operable to determine whether the HP conduit corresponding to the pump is pressurized by comparing a predetermined threshold to the fluid pressure indicated by the information generated by the corresponding one of the sensors.

[0094] With respect to each of the pumps, the controller may be further operable to: determine whether the LP valve corresponding to the pump is in the closed flow position; and determine whether the one of the HP valve corresponding to the pump and the bleed valve corresponding to the pump is in the open flow position.

[0095] Prior to causing the transition of the LP, HP, and/or bleed valves corresponding to each of the pumps, the controller may be further operable to cause each of the pumps to commence operation.

[0096] Prior to causing each of the pumps to commence operation, the controller may be further operable to, with respect to each of the pumps: remotely control the LP, HP, and bleed valves corresponding to the pump by transmitting corresponding command signals to the LP, HP, and bleed valves to transition the LP, HP, and bleed valves to corresponding intended settings; after transmitting the command signals, receive corresponding feedback signals from the LP, HP, and bleed valves corresponding to the pump, wherein the feedback signals are indicative of corresponding actual settings of the LP, HP, and bleed valves; and assess an operational health of each of the LP, HP, and bleed valves corresponding to the pump based on the corresponding intended and actual settings.

[0097] The controller may be further operable to, after causing the transitions of the LP valve and the one of the HP and bleed valves corresponding to each of the pumps, cause each of the pumps to operate at an increased flow output.

[0098] The plurality of sensors may be a plurality of pressure sensors, the apparatus may further comprise a plurality of flow sensors in communication with the controller and each operable to generate information indicative of rate of fluid flow through a corresponding one of HP conduits, and the controller may be further operable to, with respect to each of the pumps, determine whether the HP conduit corresponding to the pump is substantially flushed based on the information generated by the corresponding one of the flow sensors. With respect to each of the pumps, the controller may be further operable to determine whether the HP conduit corresponding to the pump is substantially flushed by comparing a predetermined threshold to the flow rate indicated by the information generated by the corresponding one of the flow sensors, and the HP conduit may be substantially flushed when the predetermined threshold is greater than the flow rate indicated by the information generated by the corresponding one of the flow sensors. The controller may be further operable to cause each of the pumps to cease operation after determining that the HP conduits corresponding to each of the pumps are each substantially flushed. After causing each of the pumps to cease operation, the controller may be further operable to, with respect to each of the pumps: remotely control the LP, HP, and bleed valves corresponding to the pump by transmitting corresponding command signals to the LP, HP, and bleed valves to transition the LP, HP, and bleed valves to corresponding intended settings; after transmitting the command signals, receive corresponding feedback signals from the LP, HP, and bleed valves corresponding to the pump, wherein the feedback signals are indicative of corresponding actual settings of the LP, HP, and bleed valves; and assess an

operational health of each of the LP, HP, and bleed valves corresponding to the pump based on the corresponding intended and actual settings.

[0099] The present disclosure also introduces a method comprising: (a) providing a plurality of pumps and a manifold unit, wherein the manifold unit comprises: (1) a low-pressure (LP) manifold having a plurality of LP ports; (2) a plurality of LP valves each operable to control flow through a corresponding one of the LP ports; (3) a high-pressure (HP) manifold having a plurality of HP ports; (4) a plurality of HP valves each operable to control flow through a corresponding one of the HP ports; (5) a plurality of bleed ports each fluidly coupled with a corresponding one of the HP ports; and (6) a plurality of bleed valves each fluidly coupled with and remotely operable to control flow through a corresponding one of the bleed ports from the corresponding HP port; (b) fluidly coupling each of the pumps with the LP manifold via a plurality of LP conduits each fluidly coupling a corresponding one of the pumps with a corresponding one of the LP ports; (c) fluidly coupling each of the pumps with the HP manifold via a plurality of HP conduits each fluidly coupling a corresponding one of the pumps with a corresponding one of the HP ports; (d) establishing communication between a controller and each of the LP valves, the HP valves, the bleed valves, the pumps, and a plurality of sensors each operable to generate information indicative of fluid pressure within a corresponding one of the HP conduits; and (e) operating the controller to, with respect to each of the pumps: (1) cause the pump to operate and then: (i) cause the LP valve corresponding to the pump to transition to a closed flow position; and (ii) cause one of the HP valve corresponding to the pump and the bleed valve corresponding to the pump to transition to an open flow position; and (2) then determine that the HP conduit corresponding to the pump is not pressurized based on the information generated by the corresponding one of the sensors.

[00100] The method may further comprise, with respect to each of the pumps, fluidly uncoupling the pump from the manifold unit after the controller determines that the HP conduit corresponding to the pump is not pressurized.

[00101] The method may further comprise operating the controller to, with respect to each of the pumps: confirm that the LP valve corresponding to the pump is in the closed flow position; and confirm that the one of the HP valve corresponding to the pump and the bleed valve corresponding to the pump is in the open flow position.

[00102] The method may further comprise operating the controller to, with respect to each of the pumps: remotely control the LP, HP, and bleed valves corresponding to the pump by

transmitting corresponding command signals to the LP, HP, and bleed valves to transition the LP, HP, and bleed valves from corresponding existing settings to corresponding intended settings; after transmitting the command signals, receive corresponding feedback signals from the LP, HP, and bleed valves corresponding to the pump indicative of corresponding actual settings of the LP, HP, and bleed valves; and assess an operational health of each of the LP, HP, and bleed valves corresponding to the pump based on the corresponding intended and actual settings.

[00103] The method may further comprise, after operating the controller to cause the transition of the LP valve and the one of the HP and bleed valves corresponding to each of the pumps, operating the controller to cause each of the pumps to operate at an increased flow output.

[00104] The plurality of sensors may be a plurality of pressure sensors, the method may further comprise establishing communication between the controller and each of a plurality of flow sensors operable to generate information indicative of rate of fluid flow within a corresponding one of the HP conduits, and the controller may be operable to, with respect to each of the pumps, determine whether the HP conduit corresponding to the pump is substantially flushed based on the information generated by the corresponding one of the flow sensors. The method may further comprise operating the controller to, with respect to each of the pumps, cease operation of the pump after the controller determines that the HP conduit corresponding to the pump is substantially flushed.

[00105] The foregoing outlines features of several embodiments so that a person having ordinary skill in the art may better understand the aspects of the present disclosure. A person having ordinary skill in the art should appreciate that they may readily use the present disclosure as a basis for designing or modifying other processes and structures for carrying out the same purposes and/or achieving the same advantages of the embodiments introduced herein. A person having ordinary skill in the art should also realize that such equivalent constructions do not depart from the scope of the present disclosure, and that they may make various changes, substitutions and alterations herein without departing from the spirit and scope of the present disclosure.

[00106] The Abstract at the end of this disclosure is provided to comply with 37 C.F.R. §1.72(b) to allow the reader to quickly ascertain the nature of the technical disclosure. It is

submitted with the understanding that it will not be used to interpret or limit the scope or meaning of the claims.

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WHAT IS CLAIMED IS:

1. An apparatus comprising:

a manifold unit comprising a plurality of ports and a plurality of valves, wherein each of the valves is operable to control flow through a corresponding one of the ports; and

a controller operable to, with respect to each of the valves:

remotely control the valve by transmitting a command signal to the valve to transition the valve from an existing setting to an intended setting;

after transmitting the command signal, receive a feedback signal from the valve indicative of an actual setting of the valve; and

assess an operational health of the valve based on the intended and actual settings.

2. The apparatus of claim 1 wherein the command signal is a first command signal, the feedback signal is a first feedback signal, the intended setting is a first intended setting, the actual setting is a first actual setting, and the controller is further operable to, with respect to each of the valves:

further remotely control the valve by transmitting a second command signal to the valve to transition the valve to a second intended setting;

after transmitting the second command signal, receive a second feedback signal from the valve indicative of a second actual setting of the valve; and

reassess the operational health of the valve based on the second intended setting and the second actual setting.

3. The apparatus of claim 2 wherein the first intended setting is a closed flow setting and the second intended setting is an open flow setting.

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4. The apparatus of claim 2 wherein the controller is further operable to, with respect to each of the valves:

further remotely control the valve by transmitting a third command signal to the valve to transition the valve to a third intended setting;

after transmitting the third command signal, receive a third feedback signal from the valve indicative of a third actual setting of the valve; and

reassess the operational health of the valve based on the third intended setting and the third actual setting.

5. The apparatus of claim 4 wherein the third intended setting is a closed flow setting.

6. The apparatus of claim 1 wherein the plurality of valves comprises a first valve, a second valve, and a third valve, and wherein the controller is operable to:

remotely control the first valve by transmitting a first command signal to the first valve to transition the first valve to a first intended setting, then receive a first feedback signal from the first valve indicative of a first actual setting of the first valve, and then assess a first operational health of the first valve based on the first intended setting and the first actual setting;

after assessing the first operational health, remotely control the second valve by transmitting a second command signal to the second valve to transition the second valve to a second intended setting, then receive a second feedback signal from the second valve indicative of a second actual setting of the second valve, and then assess a second operational health of the second valve based on the second intended setting and the second actual setting; and

after assessing the second operational health, remotely control the third valve by transmitting a third command signal to the third valve to transition the third valve to a third intended setting, then receive a third feedback signal from the third valve indicative of a third actual setting of the third valve, and then assess a third operational health of the third valve based on the third intended setting and the third actual setting.

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7. A method comprising:

establishing communication between a controller and each of a plurality of valves of a manifold unit, wherein each of the valves is operable to control flow through a corresponding one of a plurality of ports of the manifold unit; and

operating the controller to, with respect to each of the valves:

remotely control the valve by transmitting a command signal to the valve to transition the valve from an existing setting to an intended setting;

after transmitting the command signal, receive a feedback signal from the valve indicative of an actual setting of the valve; and

assess an operational health of the valve based on the intended and actual settings.

8. The method of claim 7 wherein the command signal is a first command signal, the feedback signal is a first feedback signal, the intended setting is a first intended setting, the actual setting is a first actual setting, and wherein the method further comprises operating the controller to, with respect to each of the valves:

further remotely control the valve by transmitting a second command signal to the valve to transition the valve to a second intended setting;

after transmitting the second command signal, receive a second feedback signal from the valve indicative of a second actual setting of the valve; and

reassess the operational health of the valve based on the second intended setting and the second actual setting.

9. The method of claim 8 wherein the first intended setting is a closed flow setting and the second intended setting is an open flow setting.

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10. The method of claim 8 further comprising operating the controller to, with respect to each of the valves:

further remotely control the valve by transmitting a third command signal to the valve to transition the valve to a third intended setting;

after transmitting the third command signal, receive a third feedback signal from the valve indicative of a third actual setting of the valve; and

reassess the operational health of the valve based on the third intended setting and the third actual setting.

11. The method of claim 10 wherein the third intended setting is a closed flow setting.

12. The method of claim 8 wherein the plurality of valves comprises a first valve, a second valve, and a third valve, and wherein operating the controller includes:

remotely controlling the first valve by transmitting a first command signal to the first valve to transition the first valve to a first intended setting, then receiving a first feedback signal from the first valve indicative of a first actual setting of the first valve, and then assessing a first operational health of the first valve based on the first intended setting and the first actual setting;

after assessing the first operational health, remotely controlling the second valve by transmitting a second command signal to the second valve to transition the second valve to a second intended setting, then receiving a second feedback signal from the second valve indicative of a second actual setting of the second valve, and then assessing a second operational health of the second valve based on the second intended setting and the second actual setting; and

after assessing the second operational health, remotely controlling the third valve by transmitting a third command signal to the third valve to transition the third valve to a third intended setting, then receiving a third feedback signal from the third valve indicative of a third actual setting of the third valve, and then assessing a third operational health of the third valve based on the third intended setting and the third actual setting.

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13. An apparatus comprising:

a manifold unit comprising:

a low-pressure (LP) manifold having a plurality of LP ports;

a plurality of LP valves each operable to control flow through a corresponding one of the LP ports;

a high-pressure (HP) manifold having a plurality of HP ports;

a plurality of HP valves each operable to control flow through a corresponding one of the HP ports;

a plurality of bleed ports each fluidly coupled with a corresponding one of the HP ports; and

a plurality of bleed valves each fluidly coupled with and remotely operable to control flow through a corresponding one of the bleed ports from the corresponding HP port;

a plurality of pumps;

a plurality of LP conduits each fluidly coupling a corresponding one of the pumps and a corresponding one of the LP ports;

a plurality of HP conduits each fluidly coupling a corresponding one of the pumps and a corresponding one of the HP ports;

a plurality of sensors each operable to generate information indicative of fluid pressure within a corresponding one of the HP conduits; and

a controller in communication with the LP valves, the HP valves, the bleed valves, the sensors, and the pumps, wherein the controller is operable to, with respect to each of the pumps:

cause the LP valve corresponding to the pump to transition to a closed flow position;

cause one of the HP valve corresponding to the pump and the bleed valve corresponding to the pump to transition to an open flow position; and

determine whether the HP conduit corresponding to the pump is pressurized based on the information generated by the corresponding one of the sensors.

14. The apparatus of claim 13 wherein, with respect to each of the pumps, the controller is operable to determine whether the HP conduit corresponding to the pump is pressurized by comparing a predetermined threshold to the fluid pressure indicated by the information generated by the corresponding one of the sensors.

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15. The apparatus of claim 13 wherein, with respect to each of the pumps, the controller is further operable to:

determine whether the LP valve corresponding to the pump is in the closed flow position; and

determine whether the one of the HP valve corresponding to the pump and the bleed valve corresponding to the pump is in the open flow position.

16. The apparatus of claim 13 wherein:

prior to causing the transition of the LP, HP, and/or bleed valves corresponding to each of the pumps, the controller is further operable to cause each of the pumps to commence operation; and

prior to causing each of the pumps to commence operation, the controller is further operable to, with respect to each of the pumps:

remotely control the LP, HP, and bleed valves corresponding to the pump by transmitting corresponding command signals to the LP, HP, and bleed valves to transition the LP, HP, and bleed valves to corresponding intended settings;

after transmitting the command signals, receive corresponding feedback signals from the LP, HP, and bleed valves corresponding to the pump, wherein the feedback signals are indicative of corresponding actual settings of the LP, HP, and bleed valves; and

assess an operational health of each of the LP, HP, and bleed valves corresponding to the pump based on the corresponding intended and actual settings.

17. The apparatus of claim 13 wherein the controller is further operable to, after causing the transitions of the LP valve and the one of the HP and bleed valves corresponding to each of the pumps, cause each of the pumps to operate at an increased flow output.

18. The apparatus of claim 13 wherein the plurality of sensors is a plurality of pressure sensors, wherein the apparatus further comprises a plurality of flow sensors in communication with the controller and each operable to generate information indicative of rate of fluid flow through a corresponding one of HP conduits, and wherein the controller is further operable to, with respect to each of the pumps, determine whether the HP conduit corresponding to the pump is substantially flushed based on the information generated by the corresponding one of the flow sensors.

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19. The apparatus of claim 18 wherein, with respect to each of the pumps, the controller is further operable to determine whether the HP conduit corresponding to the pump is substantially flushed by comparing a predetermined threshold to the flow rate indicated by the information generated by the corresponding one of the flow sensors, and wherein the HP conduit is substantially flushed when the predetermined threshold is greater than the flow rate indicated by the information generated by the corresponding one of the flow sensors.

20. The apparatus of claim 18 wherein:

the controller is further operable to cause each of the pumps to cease operation after determining that the HP conduits corresponding to each of the pumps are each substantially flushed; and

after causing each of the pumps to cease operation, the controller is further operable to, with respect to each of the pumps:

remotely control the LP, HP, and bleed valves corresponding to the pump by transmitting corresponding command signals to the LP, HP, and bleed valves to transition the LP, HP, and bleed valves to corresponding intended settings;

after transmitting the command signals, receive corresponding feedback signals from the LP, HP, and bleed valves corresponding to the pump, wherein the feedback signals are indicative of corresponding actual settings of the LP, HP, and bleed valves; and

assess an operational health of each of the LP, HP, and bleed valves corresponding to the pump based on the corresponding intended and actual settings.

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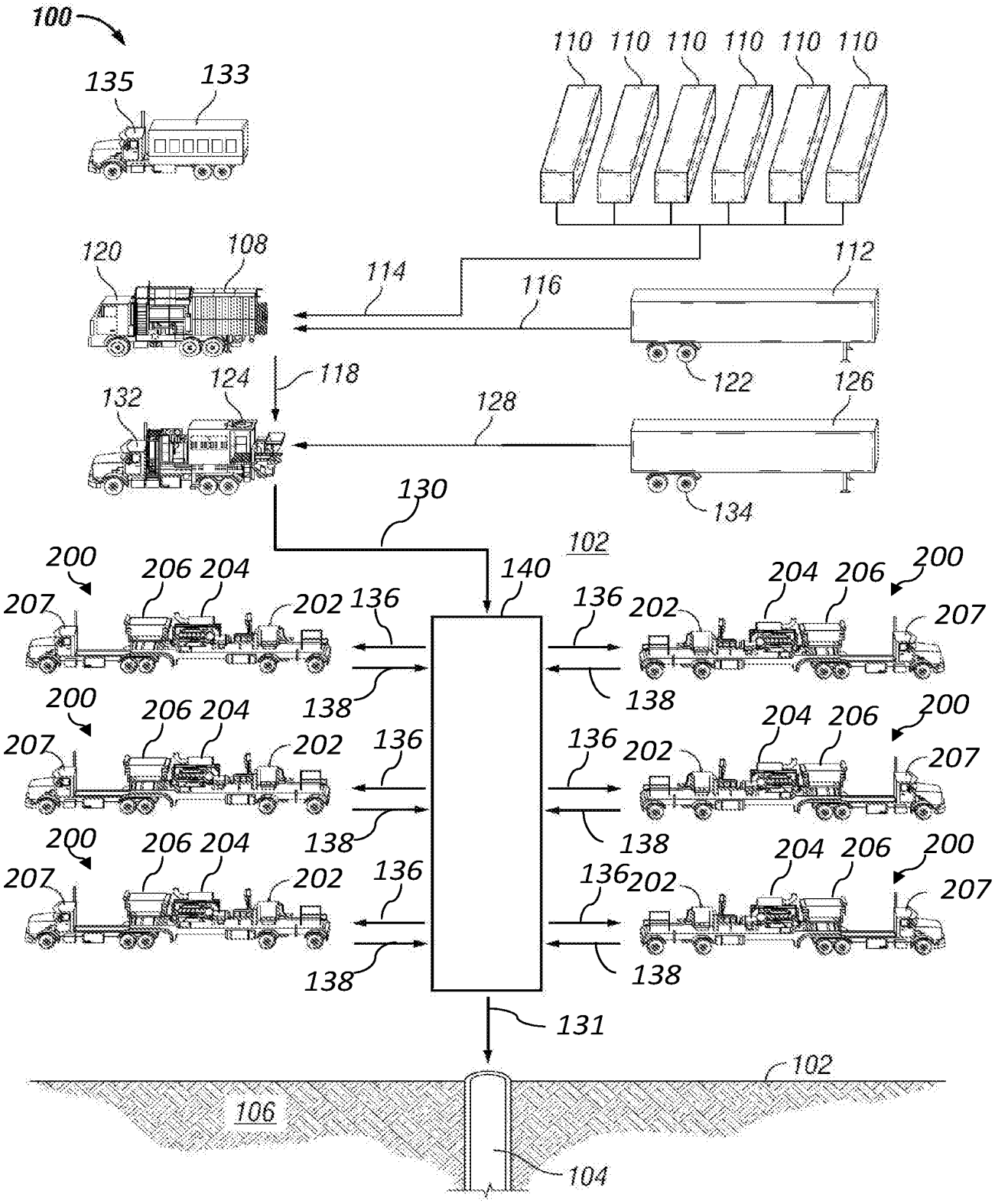

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FIG. 1

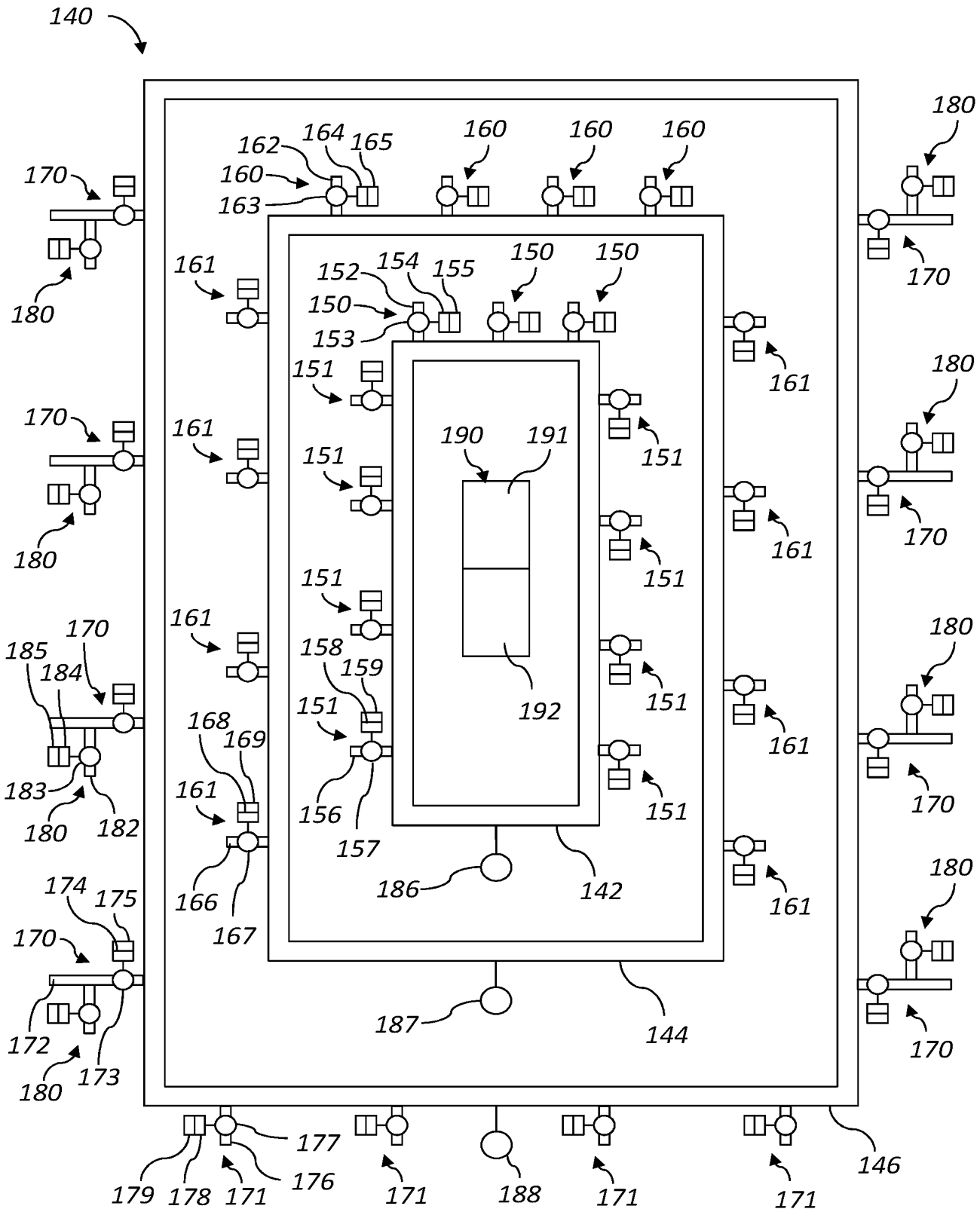

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FIG. 2

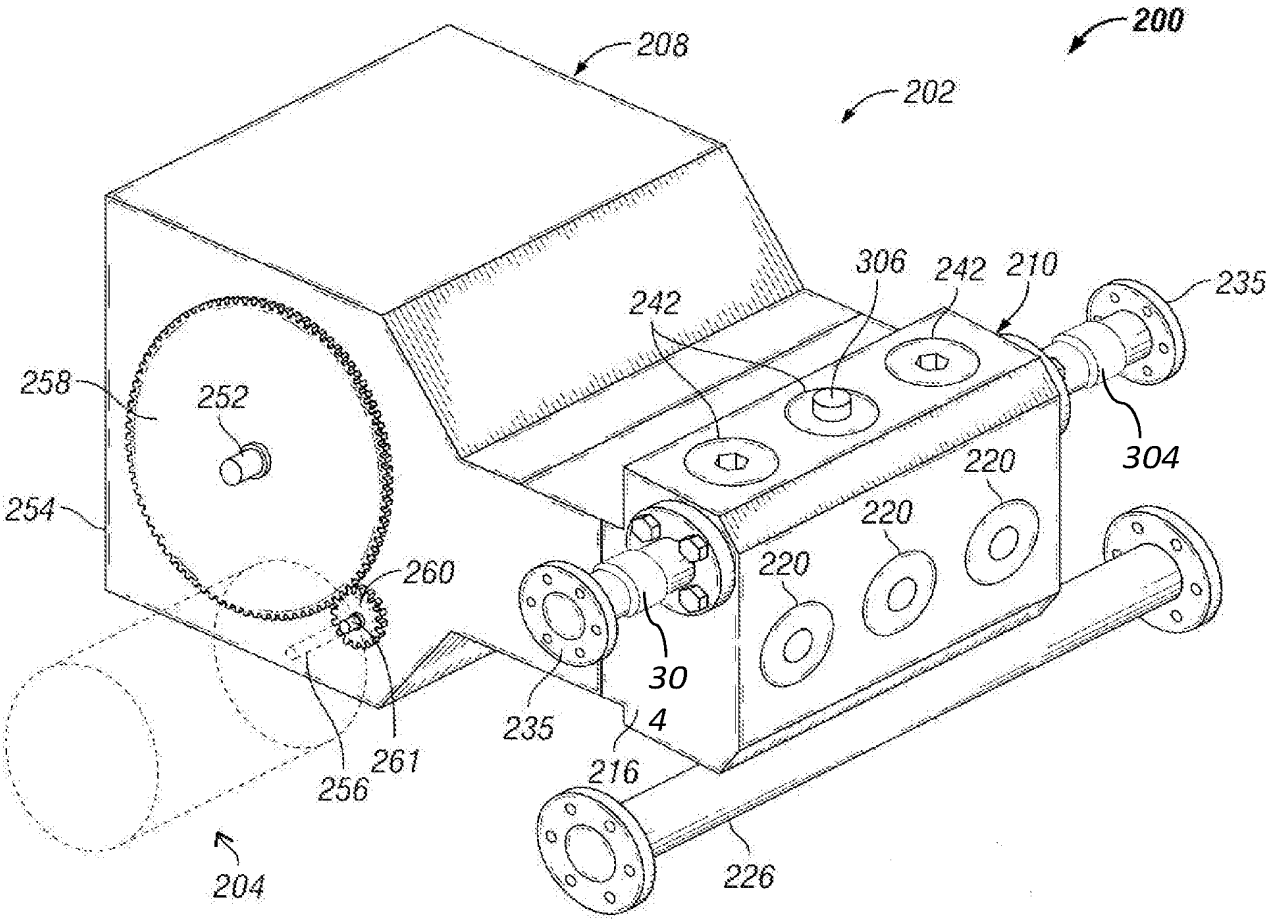

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FIG. 3

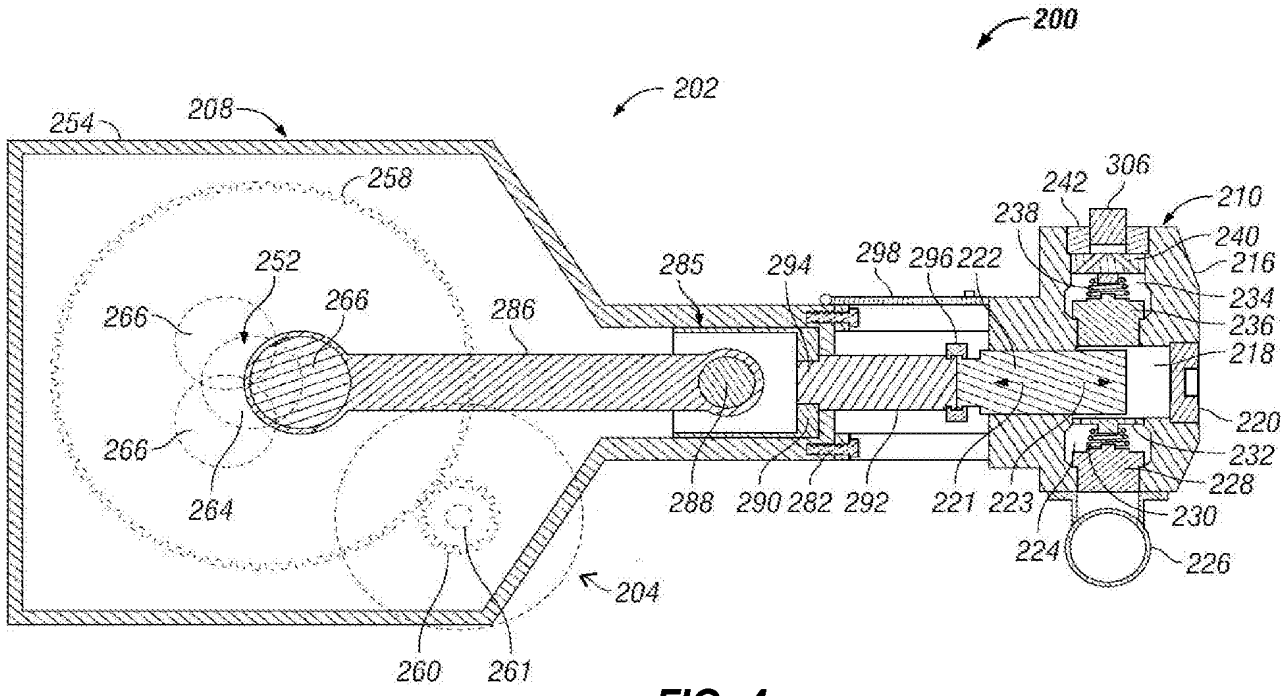

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FIG. 4

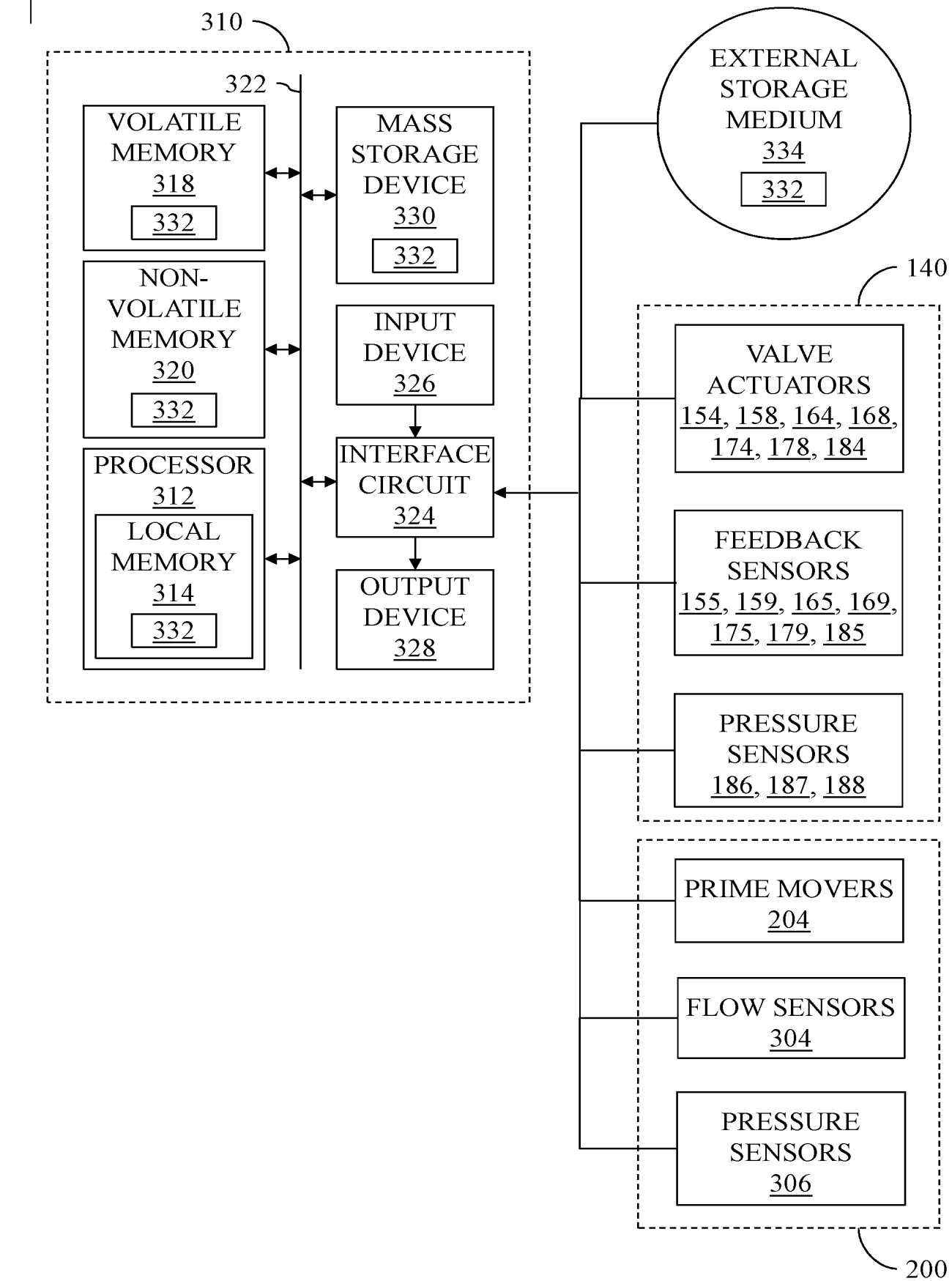

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322
VOLATILE MEMORY 318
332
NON-VOLATILE MEMORY 320
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PROCESSOR 312
LOCAL MEMORY 314
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MASS STORAGE DEVICE 330
332
INPUT DEVICE 326
INTERFACE CIRCUIT 324
OUTPUT DEVICE 328
EXTERNAL STORAGE MEDIUM 334
332
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VALVE ACTUATORS 154, 158, 164, 168, 174, 178, 184
FEEDBACK SENSORS 155, 159, 165, 169, 175, 179, 185
PRESSURE SENSORS 186, 187, 188
PRIME MOVERS 204
FLOW SENSORS 304
PRESSURE SENSORS 306
200

FIG. 5

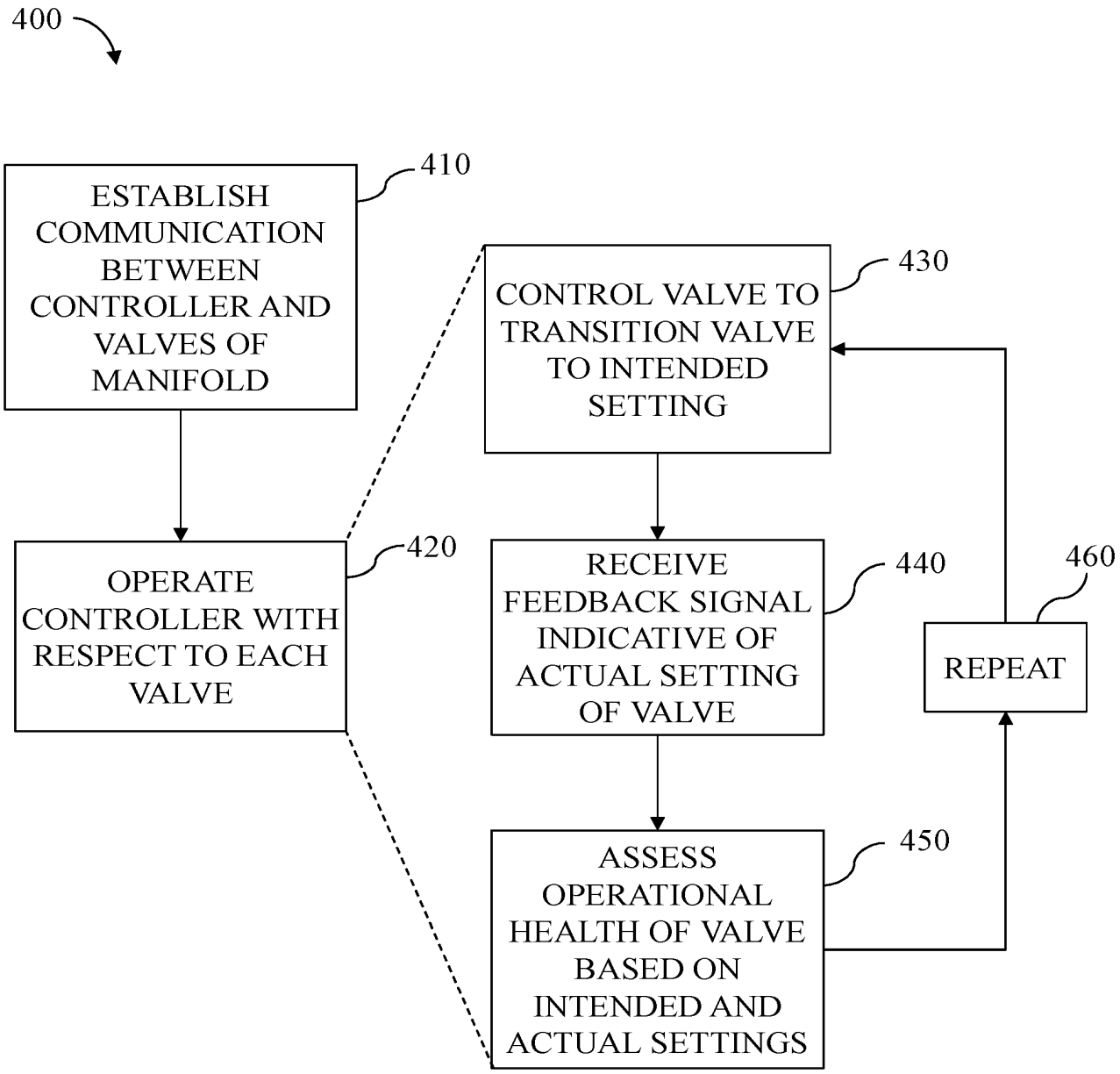

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ESTABLISH COMMUNICATION BETWEEN CONTROLLER AND VALVES OF MANIFOLD
410
OPERATE CONTROLLER WITH RESPECT TO EACH VALVE
420
CONTROL VALVE TO TRANSITION VALVE TO INTENDED SETTING
430
RECEIVE FEEDBACK SIGNAL INDICATIVE OF ACTUAL SETTING OF VALVE
440
ASSESS OPERATIONAL HEALTH OF VALVE BASED ON INTENDED AND ACTUAL SETTINGS
450
REPEAT
460

FIG. 6

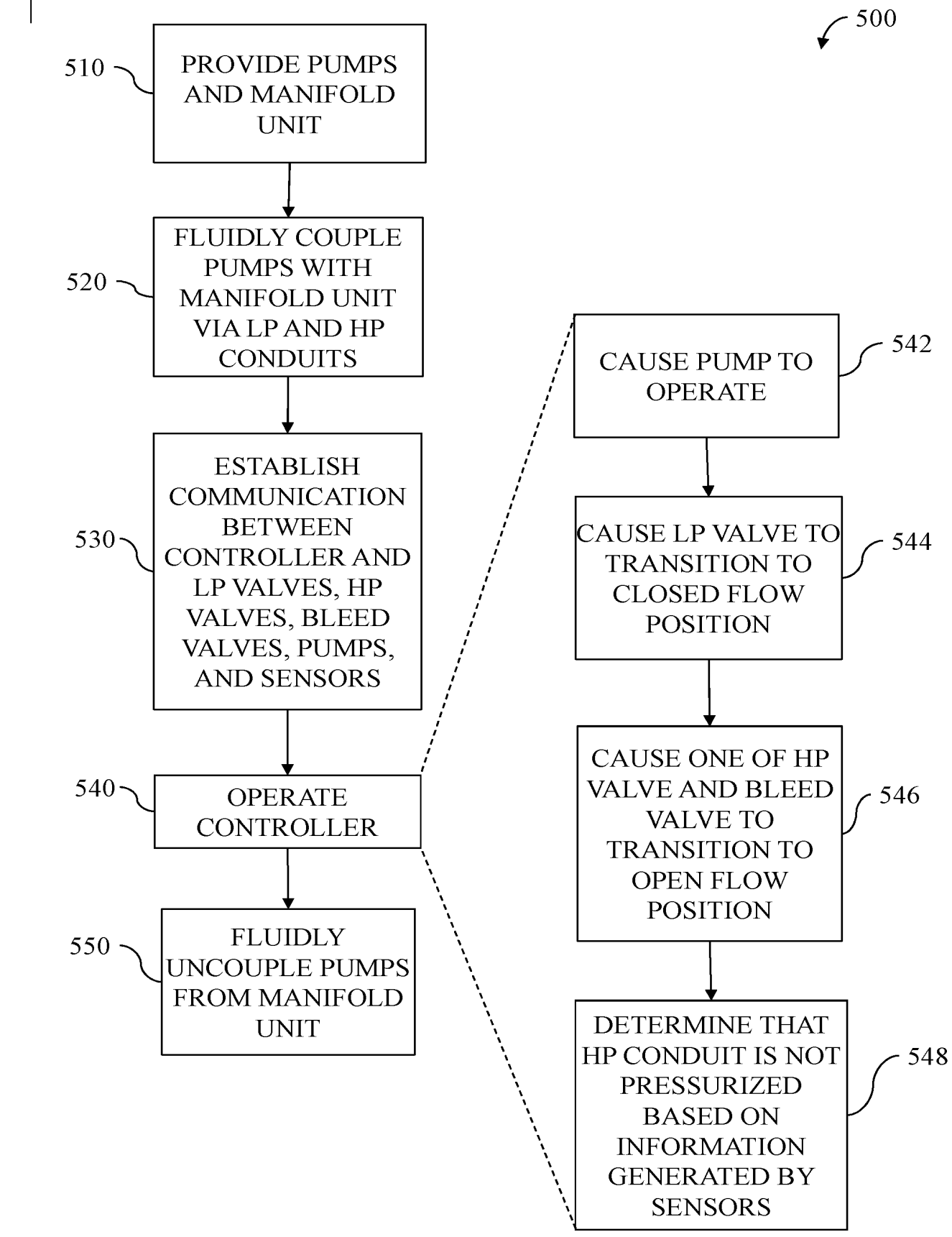

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PROVIDE PUMPS AND MANIFOLD UNIT
520
FLUIDLY COUPLE PUMPS WITH MANIFOLD UNIT VIA LP AND HP CONDUITS
530
ESTABLISH COMMUNICATION BETWEEN CONTROLLER AND LP VALVES, HP VALVES, BLEED VALVES, PUMPS, AND SENSORS
540
OPERATE CONTROLLER
550
FLUIDLY UNCOUPLE PUMPS FROM MANIFOLD UNIT
542
CAUSE PUMP TO OPERATE
544
CAUSE LP VALVE TO TRANSITION TO CLOSED FLOW POSITION
546
CAUSE ONE OF HP VALVE AND BLEED VALVE TO TRANSITION TO OPEN FLOW POSITION
548
DETERMINE THAT HP CONDUIT IS NOT PRESSURIZED BASED ON INFORMATION GENERATED BY SENSORS

FIG. 7

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2016/021336

A. CLASSIFICATION OF SUBJECT MATTER

F17D 3/01(2006.01)i, F17D 1/00(2006.01)i, F17D 1/14(2006.01)i, F17D 1/02(2006.01)i, E21B 7/18(2006.01)i, E21B 33/14(2006.01)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)
F17D 3/01; E21B 47/00; E21B 43/26; E21B 29/02; B60S 5/02; F17D 1/00; F17D 1/14; F17D 1/02; E21B 7/18; E21B 33/14

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: manifold unit, port, valve, controller, existing setting, intended setting, actual setting, operational health, pump, and sensor

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	WO 2014-158806 A1 (SCHLUMBERGER CANADA LIMITED et al.) 02 October 2014 See paragraphs [0035]-[0045], [0053], [0063]-[0077] and figures 1-6, 14.	1-20
Y	US 2014-0090475 A1 (GENERAL ELECTRIC COMPANY) 03 April 2014 See paragraphs [0033]-[0036] and figure 4.	1-12,16,20
Y	US 4821564 A (PEARSON et al.) 18 April 1989 See column 7, line 22 - column 8, line 24 and figure 1.	13-20
A	US 2013-0284455 A1 (GE OIL & GAS PRESSURE CONTROL LP) 31 October 2013 See paragraphs [0028]-[0033] and figures 1-2.	1-20
A	US 2004-0140092 A1 (ROBISON, CLARK E.) 22 July 2004 See paragraph [0037] and figure 9.	1-20

☐ Further documents are listed in the continuation of Box C.

☒ See patent family annex.

* Special categories of cited documents:
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"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	Date of mailing of the international search report
31 May 2016 (31.05.2016)	**02 June 2016 (02.06.2016)**

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INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2016/021336

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
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(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
6 October 2016 (06.10.2016)

WIPO | PCT

(10) International Publication Number
WO 2016/160458 A1

(51) International Patent Classification:
E21B 33/13 (2006.01) *G05B 19/02* (2006.01)
E21B 33/138 (2006.01) *G06F 19/00* (2011.01)

(21) International Application Number:
PCT/US2016/023856

(22) International Filing Date:
24 March 2016 (24.03.2016)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
62/139,963 30 March 2015 (30.03.2015) US

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(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE,

[Continued on next page]

(54) Title: AUTOMATED OPERATION OF WELLSITE EQUIPMENT

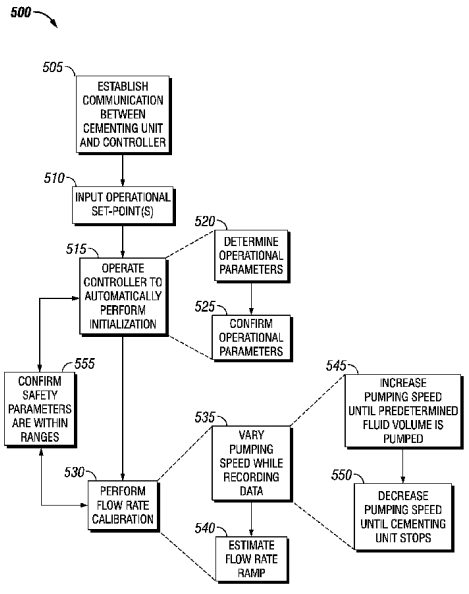


FIG. 6

(57) Abstract: Systems and methods for controlling wellsite equipment, including a cementing unit comprising a plurality of sensors operable to generate information related to operational status of the cementing unit and a controller comprising a processor and a memory including computer program code. Communication is established between the cementing unit and the controller. The controller is operable to operate the controller to automatically perform initialization of operation of the cementing unit, operate the controller to automatically perform a flow rate calibration of the cementing unit, and/or operate the controller to automatically perform a cement pumping operation of the cementing unit.

WO 2016/160458 A1

DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Published:

— *with international search report (Art. 21(3))*

AUTOMATED OPERATION OF WELLSITE EQUIPMENT

Cross-Reference to Related Applications

[0001] This application claims priority to and the benefit of U.S. Provisional Application No. 62/139,963, titled "WELL CEMENTING METHODS," filed March 30, 2015, the entire disclosure of which is hereby incorporated herein by reference.

Background of the Disclosure

[0002] High-volume, high-pressure pumps are utilized at wellsites for a variety of pumping operations. Such operations may include drilling, cementing, acidizing, water jet cutting, hydraulic fracturing, and other wellsite operations. In some pumping operations, several pumps may be fluidly connected to a well via various fluid conduits and/or a manifold. During such operations, the fluid conduits and/or the manifold distributes low-pressure fluid from a mixer, a blender, and/or other sources among the pumps and combines pressurized fluid from the pumps for injection into the well. The fluid conduits and/or the manifold may have a large physical size and weight to satisfy intended fluid flow rates and operating pressures generated by the pumps.

[0003] Success of the pumping operations at a wellsite may be affected by many factors, including efficiency, failure rates, and safety related to operation of the pumps and the manifold. High fluid pressures, flow rates, and vibrations generated by the pumps may cause mechanical fatigue, wear, and other damage to the pumps and various downstream equipment, including the manifold and associated fluid sensors, valves, couplings, and conduits. Mechanical fatigue and wear may cause leaks and/or other failures in the pumps and the various downstream equipment.

[0004] To ensure that the wellsite equipment operates as intended, human operators at the wellsite may perform pressure and flow rate calibrations, diagnostics, and other tests before commencing actual downhole pumping operations. To perform such tests and to oversee the actual downhole pumping operations, the operators typically approach the wellsite equipment to visually inspect the fluid sensors and to manually adjust the fluid valves, thus exposing themselves to a potentially dangerous environment. Approaching wellsite equipment during testing or pumping operations may be dangerous, such as because high-pressure fluid within such equipment may escape, which may lead to serious injuries. Also, performing the testing and pumping operations manually may result in inconsistent equipment settings and, thus, inconsistent performance between different operational stages or jobs caused by human error.

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Summary of the Disclosure

[0005] 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 indispensable features of the claimed subject matter, nor is it intended for use as an aid in limiting the scope of the claimed subject matter.

[0006] The present disclosure introduces a method that includes establishing communication between a cementing unit and a controller operable to control operation of the cementing unit. The controller includes a processor and a memory including computer program code. The method also includes inputting a fluid volume set-point and operating the controller to automatically perform a flow rate calibration of the cementing unit and a cement pumping operation of the cementing unit. The flow rate calibration includes automatically: varying pumping speed of the cementing unit while recording first pumping speeds and corresponding first flow rates generated by the cementing unit; and determining a flow rate ramp relating the recorded first flow rates to the corresponding recorded first pumping speeds. The cement pumping operation includes automatically: (a) increasing pumping speed of the cementing unit while recording: (i) second pumping speeds; (ii) first pressures generated by the cementing unit corresponding to the recorded second pumping speeds; and (iii) second flow rates generated by the cementing unit corresponding to the recorded second pumping speeds and/or first pressures; then (b) maintaining the pumping speed while recording the maintained pumping speed and corresponding second pressures and third flow rates; and then (c) decreasing the pumping speed while recording fourth pumping speeds and corresponding third pressures and fourth flow rates until the cementing unit has stopped pumping cement and a volume of the pumped cement is substantially equal to the fluid volume set-point.

[0007] The present disclosure also introduces a method that includes establishing communication between a cementing unit and a controller operable to control operation of the cementing unit. The cementing unit includes sensors operable to generate information related to operational status of the cementing unit, and the controller includes a processor and a memory including computer program code. The method also includes operating the controller to automatically perform initialization of the cementing unit. The initialization includes automatically: determining operational parameters related to the cementing unit operational status based on the information generated by the sensors; and confirming the operational parameters are within corresponding predetermined ranges.

[0008] The present disclosure also introduces a method that includes establishing communication between a cementing unit and a controller operable to control operation of the cementing unit. The controller includes a processor and a memory including computer program code. The method also includes operating the controller to automatically perform a flow rate calibration of the cementing unit. The flow rate calibration includes automatically: varying pumping speed of the cementing unit while recording the pumping speed and a corresponding flow rate generated by the cementing unit; and determining a flow rate ramp relating the recorded flow rates to the corresponding recorded pumping speeds.

[0009] The present disclosure also introduces a method that includes establishing communication between a cementing unit and a controller operable to control operation of the cementing unit. The controller includes a processor and a memory including computer program code. The method also includes inputting a fluid volume set-point, and operating the controller to automatically perform a cement pumping operation of the cementing unit. The cement pumping operation includes automatically: (1) increasing pumping speed of the cementing unit while recording the pumping speed, pressure generated by the cementing unit and corresponding to the pumping speed, and cement flow rate generated by the cementing unit and corresponding to the pumping speed and/or pressure; then (2) maintaining the pumping speed while recording the pumping speed and the corresponding pressure and cement flow rate; and then (3) decreasing the pumping speed while recording the pumping speed and the corresponding pressure and cement flow rate until the cementing unit has stopped pumping cement and a volume of the pumped cement is substantially equal to the fluid volume set-point.

[0010] These and additional aspects of the present disclosure are set forth in the description that follows, and/or may be learned by a person having ordinary skill in the art by reading the materials herein and/or practicing the principles described herein. At least some aspects of the present disclosure may be achieved via means recited in the attached claims.

Brief Description of the Drawings

[0011] The present disclosure is understood from the following detailed description when read with the accompanying figures. It is emphasized that, in accordance with the standard practice in the industry, various features are not drawn to scale. In fact, the dimensions of the various features may be arbitrarily increased or reduced for clarity of discussion.

[0012] FIG. 1 is a schematic view of an example implementation of apparatus according to one or more aspects of the present disclosure.

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[0013] FIG. 2 is a schematic view of a portion of an example implementation of the apparatus shown in FIG. 1 according to one or more aspects of the present disclosure.

[0014] FIG. 3 is a perspective view of a portion of an example implementation of the apparatus shown in FIG. 2 according to one or more aspects of the present disclosure.

[0015] FIG. 4 is a sectional view of a portion of the apparatus shown in FIG. 3 according to one or more aspects of the present disclosure.

[0016] FIG. 5 is a schematic view of an example implementation of apparatus according to one or more aspects of the present disclosure.

[0017] FIG. 6 is a flow-chart diagram of at least a portion of an example implementation of a method according to one or more aspects of the present disclosure.

[0018] FIG. 7 is a flow-chart diagram of at least a portion of an example implementation of a method according to one or more aspects of the present disclosure.

[0019] FIG. 8 is a flow-chart diagram of at least a portion of an example implementation of a method according to one or more aspects of the present disclosure.

[0020] FIG. 9 is a flow-chart diagram of at least a portion of an example implementation of a method according to one or more aspects of the present disclosure.

Detailed Description

[0021] It is to be understood that the following disclosure provides many different embodiments, or examples, for implementing different features of various embodiments. Specific examples of components and arrangements are described below to simplify the present disclosure. These are, of course, merely examples and are not intended to be limiting. In addition, the present disclosure may repeat reference numerals and/or letters in the various examples. This repetition is for simplicity and clarity, and does not in itself dictate a relationship between the various embodiments and/or configurations discussed.

[0022] FIG. 1 is a schematic view of at least a portion of an example wellsite system 100 according to one or more aspects of the present disclosure. The figure depicts the wellsite system 100 located on a wellsite 102 adjacent a wellbore 104 and a partial sectional view of the subterranean formation 106 penetrated by the wellbore 104 below the wellsite 102. The wellbore 104 may terminate with a wellhead 108 at the wellsite 102. The wellsite system 100 may be operable to transfer various materials and additives from corresponding sources to a destination location for blending or mixing and eventual injection into the wellbore 104 during wellbore cementing operations.

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[0023] The wellsite system 100 may comprise a cement mixing and pumping unit 110 (referred to hereinafter as a "cementing unit") fluidly connected with one or more tanks 112 and an additive container 114. The tanks 112 may contain that which is known in the art as a base fluid, which may be or comprise fresh water, brine, and/or mud. The container 114 may contain liquid or solid chemicals or additives operable to treat the base fluid. The additives may be or comprise accelerators, retarders, fluid-loss additives, dispersants, extenders, weighting agents, lost circulation additives, among other examples. The cementing unit 110 may be operable to receive the base fluid and one or more of the additives via fluid conduits 116, 118, and mix or otherwise combine the base fluid and the additives to form that which is known in the art as a mixed fluid.

[0024] The wellsite system 100 may further comprise a bulk container 120, which may contain a bulk material that is substantially different than the additives contained within the additive container 114. For example, the bulk material may be or comprise a cement powder or bulk cement, among other examples. The cementing unit 110 may be operable to receive the bulk cement from the bulk container 120 via a conduit 122, and mix or otherwise combine the mixed fluid and the bulk cement to form a mixture, which may be or comprise that which is known in the art as a cement slurry. The cementing unit 110 may then discharge or pump the cement slurry into the wellbore 104 via one or more fluid conduits 124 and/or the wellhead 108. The one or more fluid conduits 124 may be or comprise at least a portion of that which is known in the art as a treating line.

[0025] The wellsite system 100 may further comprise a batch mixer 126 operable to receive and mix predetermined quantities of the base fluid, additives, and/or bulk cement to form predetermined quantities or batches of the mixed fluid and/or cement slurry. If utilized to store the mixed fluid, the mixed fluid may be communicated to the cementing unit 110 via a fluid conduit 128 to be mixed with the bulk cement to form the cement slurry. If utilized to store the cement slurry, the cement slurry may be communicated to the cementing unit 110 via the fluid conduit 128 and pumped by the cementing unit 110 into the wellbore 104 via the fluid conduit 124 and/or the wellhead 108.

[0026] The wellsite system 100 may also comprise a control/power center 130, such as may be operable to provide control and/or centralized electric power distribution to one or more pieces of wellsite equipment or portions of the wellsite system 100. The control/power center 130 may be operable to monitor and control at least a portion of the wellsite system 100 during cementing operations. For example, the control/power center 130 may be operable to monitor and control one or more portions of the cementing unit 110 as well as

pumps and/or conveyers (not shown) for moving the fluids, materials, and/or mixtures described above to the cementing unit 110. The control/power center 130 may comprise an engine-generator set, such as a gas turbine generator, an internal combustion engine generator, and/or other sources of electric power. Electric power and/or control signals may be communicated between the control/power center 130 and other wellsite equipment via electric conductors (not shown). However, other means of signal communication, such as wireless communication, are also within the scope of the present disclosure.

[0027] The cementing unit 110, the additive container 114, the bulk container 120, the batch mixer 126, and/or the control/power center 130 may each be disposed on corresponding trucks, trailers, and/or other mobile carriers 111, 115, 121, 127, 131, respectively, such as may permit their transportation to the wellsite 102. However, the cementing unit 110, the additive container 114, the bulk container 120, the batch mixer 126, and/or the control/power center 130 may be skidded or otherwise stationary, and/or may be temporarily or permanently installed at the wellsite 102.

[0028] FIG. 1 depicts the wellsite system 100 as being operable to form fluids and/or mixtures that may be pressurized and individually or collectively injected into the wellbore 104 during wellbore cementing operations. However, it is to be understood that the wellsite system 100 may be operable to mix and/or produce other mixtures and/or fluids that may be mixed by the cementing unit 110 and injected into the wellbore 104 during other oilfield operations, such as drilling, hydraulic fracturing, acidizing, chemical injecting, and/or water jet cutting operations, among other examples.

[0029] FIG. 2 is a schematic view of at least a portion of an example implementation of the cementing unit 110 shown in FIG. 1 according to one or more aspects of the present disclosure, and designated in FIG. 2 by reference numeral 200. The cementing unit 200 may be utilized in various implementations of a wellsite system. However, for the sake of clarity and ease of understanding, the cementing unit 200 is described below in the context of the wellsite system 100 shown in FIG. 1. Thus, the following description refers to FIGS. 1 and 2, collectively.

[0030] The cementing unit 200 comprises a mixer 202 operable to receive and mix or blend the bulk cement and the mixed fluid to form the cement slurry. The mixer 202 may be a vortex type mixer or another mixer operable to mix or blend liquids and solids. For example, the mixer 202 may receive the bulk cement from a container 204, which may temporarily store and/or direct the bulk cement received from the bulk container 120 via the conduit 122. The bulk cement may be transferred to the mixer 202 via a material transfer

conduit 206, which may comprise a volumetric or mass dry metering device (not shown) operable to control the volumetric or mass flow rate of the bulk cement into the mixer 202. The bulk cement metering device may include a metering feeder, a screw feeder, an auger, and/or conveyor, among other examples.

[0031] The mixer 202 may receive the mixed fluid from displacement tanks 210, 212 via a fluid conduit 214. Each of the displacement tanks 210, 212 may receive the additives from the additive container 114 via the conduit 118 and the base fluid from the tanks 112 via the conduit 116. Within each of the displacement tanks 210, 212 a plurality of mixing blades or other agitators 216, 218 may agitate the mixture to uniformly blend the additives with the base fluid. Each of the displacement tanks 210, 212 may be or comprise a continuous flow channel or pathway for communicating or conveying the additives and the base fluid over a period of time sufficient to permit adequate blending to occur. Each displacement tank 210, 212 may have a first-in-first-out (FIFO) mode of operation, and may comprise a vessel-type outer housing enclosing a receptacle having an elongated flow pathway or space operable to store and communicate the contents therethrough. Metering systems (not shown), such as metering pumps and/or metering valves, may control the flow rate at which the additives and the base fluid are introduced into the displacement tanks 210, 212.

[0032] One or more fluid level sensors 211, 213 may be connected or otherwise disposed in association with each of the displacement tanks 210, 212. Each level sensor 211, 213 may be operable to generate signals or information indicative of the amount of base fluid, mixed fluid, or another fluid contained within a corresponding displacement tank 210, 212. Each fluid level sensor 211, 213 may comprise conductive, capacitive, vibrating, electromechanical, ultrasonic, microwave, nucleonic, and/or other level detection means, as well as load cells and/or other types of level sensors.

[0033] The cementing unit 200 may also include one or more devices operable to pump and/or meter the base fluid or mixed fluid from the displacement tanks 210, 212 to the mixer 202 via the fluid conduit 214. For example, the cementing unit 200 may include an injection pump 220 operable to pump the mixed fluid from the displacement tanks 210, 212 to the mixer 202. The injection pump 220 may be a metering pump, such as may be operable to control the flow rate at which the base fluid or mixed fluid is introduced into the mixer 202. The injection pump 220 may also be a centrifugal or another type of fluid pump. A metering valve (not shown) may be disposed along the fluid conduit 214 to further control the flow rate at which the base fluid or mixed fluid is introduced into the mixer 202.

[0034] A controller 410 may be operable to monitor and control one or more operations of the cementing unit 200. The controller 410 may be in communication with the various metering valves, metering pumps, and other metering systems described above to adjust or otherwise control density and solids fraction of the mixed fluid, the cement slurry, and/or other mixtures. For example, the controller 410 may be operable to control the volumetric flow rates at which the base fluid and the additives are introduced into the displacement tanks 210, 210, such as to control the concentration of the mixed fluid. The controller 410 may further control the volumetric flow rates at which the bulk cement and the mixed fluid are introduced into the mixer 202, such as to control density and solids fraction of the cement slurry.

[0035] The cement slurry may be selectively discharged from the mixer 202 and received by a mixing tank 222 wherein a plurality of mixing blades or other agitators 224 may agitate the cement slurry to further blend the base fluid and bulk cement. The mixing tank 222 may be or comprise a continuous flow channel or pathway for communicating or conveying the cement slurry over a period of time sufficient to permit adequate blending to occur, such that the cement slurry may reach a predetermined level viscosity and/or comprise other properties. The mixing tank 222 may have a FIFO mode of operation, and may comprise a vessel-type outer housing enclosing a receptacle having an elongated flow pathway or space operable to store and communicate the cement slurry therethrough.

[0036] A fluid level sensor 215 may be connected or otherwise disposed in association with the mixing tank 222. The level sensor 215 may be operable to generate signals or information indicative of the amount of cement slurry or another fluid contained within the mixing tank 222. The level sensor 215 may comprise the same structure and/or mode of operation as each of the fluid level sensors 211, 213 described above.

[0037] The cement slurry may be selectively recirculated through the mixer 202 via a recirculation flow path 226 comprising one or more fluid conduits. Recirculation of the cement slurry may be conducted, for example, to perform additional blending of the cement slurry and/or to introduce additional base fluid or bulk cement to the cement slurry, such as to change the composition and/or properties of the cement slurry. Flow control valves 229, 230 may be selectively opened to permit the cement slurry to recirculate through the recirculation flow path 226. During the recirculation operations, a pump 228 may be operable to recirculate or otherwise move the cement slurry through the recirculation flow path 226 from the mixing tank 222 to the mixer 202.

[0038] The cementing unit 200 may further comprise one or more high pressure pump units 241, 242 fluidly coupled to receive the fluids from the displacement tanks 210, 212 and the mixing tank 222 and discharge the fluids into the wellbore 104. For example, the pump units 241, 242 may receive the mixed fluid or the cement slurry via inlet conduits 231, 232 fluidly connected with the displacement tanks 210, 212 and the mixing tank 222. A bypass conduit 233 may extend between the displacement tanks 210, 212 and the mixing tank 222, bypassing the pump units 241, 242. The bypass conduit 233 may be fluidly connected with the conduit 128 and the inlet conduits 231, 232, such as may permit the mixed fluid or cement slurry from the batch mixer 126 to be received by the pump units 241, 242. Although the cementing unit 200 is shown comprising two pump units 241, 242, it is to be understood that the cementing unit 200 may include other quantities of pump units within the scope of the present disclosure.

[0039] One or more flow sensors 244, 245 may be disposed along the inlet conduit 231 or otherwise in association with the pump unit 241 in a manner permitting the sensing of a fluid flow rate generated by the pump unit 241. For example, the flow sensors 244, 245 may be fluidly coupled in association with fluid inlets 326 (shown in FIG. 3) of the pump unit 241. Each of the flow sensors 244, 245 may generate a signal or information indicative of a flow rate of the fluid introduced into the pump unit 241 and, thus, facilitate monitoring of the flow rate of the fluid discharged by the pump unit 241. Similarly, one or more flow sensors 246, 247 may be disposed along the inlet conduit 232 or otherwise in association with the fluid inlets 326 of the pump unit 242. Each of the flow sensors 246, 247 may generate a signal or information indicative of a flow rate of the fluid introduced into the pump unit 242 and, thus, facilitate monitoring of the flow rate of the fluid discharged by the pump unit 242.

[0040] An inlet valve 221, 223, 225, 227 may be disposed in association with each corresponding fluid inlet 326 of each pump unit 241, 242, such as to selectively fluidly connect and disconnect each pump unit 241, 242 from the mixing tank 222, the displacement tanks 210, 212, and/or other portions of the cementing unit 200. For example, the inlet valves 221, 223 may be coupled along the inlet conduit 231 on opposing sides of the pump unit 241. Similarly, the inlet valves 225, 227 may be coupled along the inlet conduit 232 on opposing sides of the pump unit 242.

[0041] The cementing unit 200 may further comprise outlet conduits 234, 235, each fluidly connected with a corresponding fluid outlet 335 (shown in FIG. 3) of each pump unit 241, 242. Each outlet conduit 234, 235 may include a corresponding fluid outlet valve 238, 239, which may selectively fluidly connect and disconnect each pump unit 241, 242 from the

wellbore 104 and/or other portions of the cementing unit 200 located downstream from the fluid outlet valves 238, 239. The outlet conduits 234, 235 may be fluidly connected with each other via an intermediate or joining conduit 236. A fluid isolation valve 237 may be disposed along the joining conduit 236 to selectively fluidly connect and disconnect the outlet conduits 234, 235. The output conduits 234, 235 and the joining conduit 236 may be or comprise at least a portion of that which is known in the art as a treating or discharge manifold 250.

[0042] The outlet conduit 234 may be fluidly connected with a fluid conduit 240, which may be or form a portion of the fluid conduit 124 to fluidly couple the pump unit 241, and perhaps the pump unit 242, with the wellbore 104. The fluid conduit 240 may be or comprise at least a portion of that which is known in the art as a cement line 240, which may be utilized to inject the cement slurry into the wellbore 104 during cementing operations. The outlet conduit 235 may be fluidly connected with a fluid conduit 243, which may form a portion of the fluid conduit 124 to fluidly couple the pump unit 242, and perhaps pump unit 241, with the wellbore 104. The fluid conduit 243 may be or comprise at least a portion of that which is known in the art as a kill line 243, which may be utilized to inject the cement slurry into the wellbore 104 during well kill operations. The outlet conduit 234 may be selectively isolated from the cement line 240 by a fluid valve 248, while the outlet conduit 235 may be selectively isolated from the kill line 243 by a fluid valve 249. The discharge manifold 250, the fluid valves 237, 238, 239, 248, 249, the cement line 240, and the kill line 243 may be or comprise that which is known in the art as treating iron or equipment.

[0043] The fluid valves 221, 223, 225, 227, 237, 238, 239, 248, 249 may be or comprise ball valves, globe valves, butterfly valves, and/or other types of fluid valves, such as may be selectively opened and closed to permit and prevent fluid flow. Each fluid valve 221, 223, 225, 227, 237, 238, 239, 248, 249 may be actuated remotely by a corresponding actuator operatively coupled with each of the fluid valves 221, 223, 225, 227, 237, 238, 239, 248, 249. For clarity, just actuator 251 associated with the fluid inlet valve 221 is identified with a numeral in FIG. 2, however each of the other fluid valves 223, 225, 227, 237, 238, 239, 248, 249 may comprise a corresponding actuator having the same or similar structure and/or mode of operation. The actuator 251 may be or comprise an electric actuator, such as a solenoid or motor, or a fluid actuator, such as a pneumatic or hydraulic cylinder or rotary actuator. Each of the fluid valves 221, 223, 225, 227, 237, 238, 239, 248, 249 may also be actuated manually, such as by a lever (not shown).

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[0044] Each fluid valve 221, 223, 225, 227, 237, 237, 238, 239, 248, 249 may also include a corresponding position sensor operable to generate a signal or information indicative of an actual position of a corresponding fluid valve 221, 223, 225, 227, 237, 237, 238, 239, 248, 249. The position sensors may be operable to monitor in-real time the actual position of the fluid valves 221, 223, 225, 227, 237, 237, 238, 239, 248, 249, which may include an open-flow position and a closed-flow position. For clarity, just position sensor 253 associated with the fluid inlet valve 221 is identified with a numeral in FIG. 2, however each of the other fluid valves 223, 225, 227, 237, 238, 239, 248, 249 may comprise a corresponding position sensor having the same or similar structure and/or mode of operation. Furthermore, each position sensor may be disposed in association with the corresponding fluid valve 221, 223, 225, 227, 237, 237, 238, 239, 248, 249 in a manner permitting sensing of the actual position of the corresponding fluid valve 221, 223, 225, 227, 237, 237, 238, 239, 248, 249. For example, each position sensor may monitor position, orientation, and/or rotation of a fluid-blocking portion of the corresponding fluid valve 221, 223, 225, 227, 237, 237, 238, 239, 248, 249 or another moving portion of the corresponding fluid valve 221, 223, 225, 227, 237, 237, 238, 239, 248, 249, such as a rotating shaft or stem. Each position sensor may be coupled with or disposed adjacent the corresponding fluid valve 221, 223, 225, 227, 237, 237, 238, 239, 248, 249, or each position sensor may be incorporated as a part of the corresponding fluid valve 221, 223, 225, 227, 237, 237, 238, 239, 248, 249. The position sensors may be or comprise proximity sensors, such as capacitive sensors, inductive sensors, magnetic sensors, Hall effect sensors, and/or reed switches, among other examples. The position sensors may also or instead include linear position sensors, such as linear potentiometers. The position sensors may also or instead include rotary position sensors, such as encoders, rotary potentiometers, synchros, resolvers, and/or rotary variable differential transformers (RVDT), among other examples.

[0045] The discharge manifold 250 may be fluidly connected with an adjustable choke valve 252, such as may be operable to bleed or otherwise relieve fluid pressure from the discharge manifold 250. The choke valve 252 may be operable to progressively open, such as to permit the pressurized fluid within the discharge manifold 250 to relieve or otherwise flow out of the discharge manifold 250 via a relief conduit 254. The relief conduit 254 may fluidly connect the discharge manifold 250 with the displacement tanks 210, 212, such as may permit the pressurized fluid within the discharge manifold 250 to be discharged into the displacement tanks 210, 212. The choke valve 252 may be or comprise a needle valve, a

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metering valve, a butterfly valve, a globe valve, or another valve operable to progressively or gradually open and close to control rate of fluid flow permitted through the choke valve 252.

[0046] The choke valve 252 may be remotely progressively opened and closed by a corresponding actuator 256 operatively coupled with the choke valve 252. The choke valve 252 may also be progressively opened and closed manually via a lever or a wheel 258. The choke valve 252 may also include a corresponding position sensor 260 operable to generate a signal or information indicative of an actual position of the choke valve, such as to monitor in-real time the actual position of the choke valve 252. The actual positions of the choke valve 252 may include a fully-open flow position, a fully-closed flow position, and intermediate or incremental positions between the fully-open flow position and the fully-closed flow positions. Each intermediate position may be indicative of an amount or percentage that the choke valve 252 is open and, thus, indicative of the flow rate through the choke valve 252. The actuator 256 and the position sensor 260 of the choke valve 252 may comprise the same or similar structure and/or mode of operation as the actuator 251 and the position sensor 253 described above. Also, the actuator 256 and the position sensors 260 may be disposed in association with the choke valve 252 in a manner that is similar in which the actuator 251 and the position sensor 253 are disposed in association with the fluid valve 221 described above.

[0047] The cementing unit 200 may further comprise bleed valves 262, 264, fluidly connected in series between the pump units 241, 242 and the choke valve 252. The bleed valves 262, 264 may be disposed along the outlet conduit 235 and may be operable to selectively fluidly connect and disconnect the choke valve 252 from the discharge manifold 250. The bleed valves 262, 264 may be or comprise ball valves, globe valves, butterfly valves, and/or other types of fluid valves, such as may be selectively opened and closed to permit and prevent fluid flow. Each bleed valve 262, 264 may be actuated remotely by a corresponding actuator 266, 268 operatively coupled in association with the bleed valves 262, 264. Each bleed valve 262, 264 may include a corresponding position sensor 272, 274 operatively connected thereto and operable to generate a signal or information indicative of an actual position of the each bleed valve 262, 264, such as to monitor in-real time the actual position of each bleed valve 262, 264. The actual positions of the bleed valves 262, 264 may include an open-flow position and a closed-flow position. The actuators 266, 268 and the position sensors 272, 274 may comprise the same or similar structure and/or mode of operation as the actuator 251 and the position sensor 253 described above. Also, the actuators 266, 268 and the position sensors 272, 274 may be disposed in association with the

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corresponding bleed valves 262, 264 in a manner that is similar in which the actuator 251 and the position sensor 253 are disposed in association with the fluid valve 221.

[0048] The cementing unit 200 may further comprise one or more pressure sensors disposed in association with the pump units 241, 242, the discharge manifold 250, and/or the cement line 240 in a manner permitting the sensing of fluid pressure within the pump units 241, 242, the discharge manifold 250, and/or the cement line 240. Each pressure sensor may be operable to generate an electrical signal and/or information indicative of the fluid pressure within the pump units 241, 242, the discharge manifold 250, and/or cement line 240. For example, a pressure sensor 276 may be disposed in association with the cement line 240, between the wellhead 108 and the fluid valve 248. As shown in FIG. 3, a pressure sensor 317 may also or instead be disposed in association with each pump unit 241, 242 to monitor the fluid pressure within each pump unit 241, 242 and/or at the corresponding fluid outlets 335.

[0049] The controller 410 may be further operable to monitor and control other operations of the cementing unit 200. To facilitate such monitoring and control, the controller 410 may be in communication with the valve actuators 251, 256, 266, 268 to permit the controller 410 to open and close or otherwise control the fluid valves 221, 223, 225, 227, 237, 238, 239, 248, 249, 252, 262, 264. The controller 410 may be in communication with the valve position sensors 253, 260, 272, 274 to permit the controller 410 to receive the feedback signals generated by the position sensors 253, 260, 272, 274 and, thus, verify that the valves 221, 223, 225, 227, 237, 238, 239, 248, 249, 252, 262, 264 transitioned to their intended position. The controller 410 may also be in communication with one or more portions of the pump units 241, 242, such as may permit the controller 410 to activate, deactivate, and control pumping or operating speed of the pump units 241, 242, as well as the flow rate and pressure generated by the pump units 241, 242. The controller 410 may also be in communication with the pressure sensors 276, 317, the flow sensors 244, 245, 246, 247, and the fluid level sensors 211, 213, 215, such as may permit the controller 410 to receive the information indicative of fluid pressure generated by the pump units 241, 242, the flow rate generated by the pump units 241, 242, and the amount of fluid available for pumping by the pump units 241, 242. Accordingly, the controller 410 may be operable to monitor and control one or more portions of the cementing unit 200, such as to control pressure, flow rates, and/or movement of fluids, including the base fluid, the mixed fluid, and the cement slurry, to implement the example methods and/or processes described herein.

[0050] Communication between the controller 410 and the various portions of the cementing unit 200 may be via wired and/or wireless communication means. However, for

clarity and ease of understanding, such communication means are not depicted in FIG. 2, as a person having ordinary skill in the art will appreciate that such communication means are within the scope of the present disclosure. Furthermore, although the controller 410 is shown as being associated with the cementing unit 200, the controller 410 may be implemented as part of the control/power center 130 or otherwise located externally from the cementing unit 200.

[0051] FIG. 3 is a perspective view of a portion of an example implementation of the pump unit 241, 242 shown in FIG. 2 according to one or more aspects of the present disclosure, and designated in FIG. 3 by reference numeral 300. FIG. 4 is a side sectional view of a portion of the pump unit 300 shown in FIG. 3. Portions of the pump unit 300 shown in FIGS. 3 and 4 are shown in phantom lines, such as to prevent obstruction from view of other portions of the pump unit 300. The following description refers to FIGS. 1-4, collectively.

[0052] The pump unit 300 comprises a pump 302 operatively coupled with and actuated by a prime mover 304. The pump 302 includes a power section 308 and a fluid section 310. The fluid section 310 may comprise a pump housing 316 having a plurality of fluid chambers 318. One end of each fluid chamber 318 may be plugged by a cover plate 320, such as may be threadedly engaged with the pump housing 316 while an opposite end of each fluid chamber 318 may contain a reciprocating member 322 slidably disposed therein and operable to displace the fluid within the corresponding fluid chamber 318. Although the reciprocating member 322 is depicted as a plunger, the reciprocating member 322 may also be implemented as a piston, diaphragm, or another reciprocating fluid displacing member.

[0053] Each fluid chamber 318 is fluidly connected with a corresponding one of a plurality of fluid inlet cavities 324 each adapted for communicating fluid from fluid inlets 326 into a corresponding fluid chamber 318. The fluid inlets 326 may be in fluid communication with a corresponding inlet conduit 231, 232. Each fluid inlet cavity 324 may contain an inlet valve 328 operable to control fluid flow from the fluid inlets 326 into the fluid chamber 318. Each inlet valve 328 may be biased toward a closed flow position by a first spring or another biasing member 330, which may be held in place by an inlet valve stop 332. Each inlet valve 328 may be actuated to an open flow position by a selected or predetermined differential pressure between the corresponding fluid inlet cavity 324 and the fluid inlets 326.

[0054] Each fluid chamber 318 is also fluidly connected with a fluid outlet cavity 334 extending through the pump housing 316 transverse to the reciprocating members 322. The

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fluid outlet cavity 334 is adapted for communicating pressurized fluid from each fluid chamber 318 into one or more fluid outlets 335 fluidly connected at one or both ends of the fluid outlet cavity 334. The fluid outlets 335 may be in fluid communication with a corresponding outlet conduit 234, 235. The fluid section 310 also contains a plurality of outlet valves 336 each operable to control fluid flow from a corresponding fluid chamber 318 into the fluid outlet cavity 334. Each outlet valve 336 may be biased toward a closed flow position by a spring or another biasing member 338, which may be held in place by an outlet valve stop 340. Each outlet valve 336 may be actuated to an open flow position by a selected or predetermined differential pressure between the corresponding fluid chamber 318 and the fluid outlet cavity 334. The fluid outlet cavity 334 may be plugged by cover plates 342, such as may be threadedly engaged with the pump housing 316.

[0055] During pumping operations, portions of the power section 308 of the pump unit 300 rotate in a manner that generates a reciprocating linear motion to move the reciprocating members 322 longitudinally within the corresponding fluid chambers 318, thereby alternatingly drawing and displacing the fluid within the fluid chambers 318. With regard to each reciprocating member 322, as the reciprocating member 322 moves out of the fluid chamber 318, as indicated by arrow 321, the pressure of the fluid inside the corresponding fluid chamber 318 decreases, thus creating a differential pressure across the corresponding fluid inlet valve 328. The pressure differential operates to compress the biasing member 330, thus actuating the fluid inlet valve 328 to an open flow position to permit the fluid from the fluid inlets 326 to enter the corresponding fluid inlet cavity 324. The fluid then enters the fluid chamber 318 as the reciprocating member 322 continues to move longitudinally out of the fluid chamber 318 until the pressure difference between the fluid inside the fluid chamber 318 and the fluid at the fluid inlets 326 is low enough to permit the biasing member 330 to actuate the fluid inlet valve 328 to the closed flow position. As the reciprocating member 322 begins to move longitudinally back into the fluid chamber 318, as indicated by arrow 323, the pressure of the fluid inside of fluid chamber 318 begins to increase. The fluid pressure inside the fluid chamber 318 continues to increase as the reciprocating member 322 continues to move into the fluid chamber 318 until the pressure of the fluid inside the fluid chamber 318 is high enough to overcome the pressure of the fluid inside the fluid outlet cavity 334 and compress the biasing member 338, thus actuating the fluid outlet valve 336 to the open flow position and permitting the pressurized fluid to move into the fluid outlet cavity 334, the fluid outlets 335, and the corresponding fluid outlet conduit 234, 235.

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[0056] The pump unit 300 may further comprise a pressure sensor 317 disposed in association with the fluid section 310 in a manner permitting the sensing of fluid pressure at the fluid outlets 335. For example, the pressure sensor 317 may extend through one or more of the cover plates 342 or other portions of the corresponding pump housing 316 to monitor pressure within the fluid outlet cavity 334 and, thus, the fluid outlets 335 and the corresponding outlet conduits 234, 235.

[0057] The fluid flow rate generated by the pump unit 300 may depend on the physical size of the reciprocating members 322 and fluid chambers 318, as well as the pump unit operating speed, which may be defined by the speed or rate at which the reciprocating members 322 cycle or move within the fluid chambers 318. The pumping speed, such as the speed or the rate at which the reciprocating members 322 move, may be related to the rotational speed of the power section 308 and/or the prime mover 304. Accordingly, the fluid flow rate generated by the pump unit 300 may be controlled by controlling the rotational speed of the power section 308 and/or the prime mover 304.

[0058] The prime mover 304 may comprise an engine, such as a gasoline engine or a diesel engine, an electric motor, such as a synchronous or asynchronous electric motor, including a synchronous permanent magnet motor, a hydraulic motor, or another prime mover operable to drive or otherwise rotate a drive shaft 352 of the power section 308. The drive shaft 352 may be enclosed and maintained in position by a power section housing 354. To prevent relative rotation between the power section housing 354 and the prime mover 304, the power section housing 354 and prime mover 304 may be fixedly coupled together or to a common base, such as a trailer of the mobile carrier 111.

[0059] The prime mover 304 may comprise a rotatable output shaft 356 operatively connected with the drive shaft 352 by a gear train or transmission 362, which may comprise at least one spur gear 358 coupled with the drive shaft 352 and at least one pinion gear 360 coupled with a support shaft 361. The output shaft 356 and the support shaft 361 may be coupled, such as may facilitate transfer of torque from the prime mover 304 to the support shaft 361, the pinion gear 360, the spur gear 358, and the drive shaft 352. For clarity, FIGS. 3 and 4 show the transmission 362 comprising a single spur gear 358 engaging a single pinion gear 360, however, it is to be understood that the transmission 362 may comprise two or more sets of gears, such as may permit the transmission 362 to be shifted between different gear configurations to control the operating speed of the drive shaft 352 and/or torque transferred to the drive shaft 352. Accordingly, the transmission 362 may be shifted to

control the rotational speed of the power section 308 and, thus, the pumping speed of the pump unit 300 to control the fluid flow rate generated by the pump unit 300.

[0060] The drive shaft 352 may be implemented as a crankshaft comprising a plurality of axial journals 364 and offset journals 366. The axial journals 364 may extend along a central axis of rotation of the drive shaft 352, while the offset journals 366 may be offset from the central axis of rotation by a selected or predetermined distance and spaced 120 degrees apart with respect to the axial journals 364. The drive shaft 352 may be supported in position within the power section 308 by the power section housing 354, wherein two of the axial journals 364 may extend through opposing openings in the power section housing 354.

[0061] The power section 308 and the fluid section 310 may be coupled or otherwise connected together. For example, the pump housing 316 may be fastened with the power section housing 354 by a plurality of threaded fasteners 382. The pump 302 may further comprise an access door 398, which may facilitate access to portions of the pump 302 located between the power section 308 and the fluid section 310, such as during assembly and/or maintenance of the pump 302.

[0062] To transform and transmit the rotational motion of the drive shaft 352 to a reciprocating linear motion of the reciprocating members 322, a plurality of crosshead mechanisms 385 may be utilized. For example, each crosshead mechanism 385 may comprise a connecting rod 386 pivotally coupled with a corresponding offset journal 366 at one end and with a pin 388 of a crosshead 390 at an opposing end. During pumping operations, walls and/or interior portions of the power section housing 354 may guide each crosshead 390, such as may reduce or eliminate lateral motion of each crosshead 390. Each crosshead mechanism 385 may further comprise a piston rod 392 coupling the crosshead 390 with the reciprocating member 322. The piston rod 392 may be coupled with the crosshead 390 via a threaded connection 394 and with the reciprocating member 322 via a flexible connection 396.

[0063] The pump unit 300 may further comprise one or more rotary sensors 311 operable to generate a signal or information indicative of rotational position, rotational speed, and/or operating frequency of the pump 302. For example, one or more of the rotary sensors 311 may be operable to convert angular position or motion of the drive shaft 352 or another rotating portion of the power section 308 to an electrical signal indicative of pumping speed of the pump unit 300. The rotary sensor 311 may be mounted in association with an external portion of the drive shaft 352 or other rotating members of the power section 308. The rotary sensor 311 may also or instead be mounted in association of the prime mover 304 to monitor

the rotational position and/or rotational speed of the prime mover 304, which may be utilized to determine the pumping speed of the pump unit 300. The rotary sensor 311 may be or comprise an encoder, a rotary potentiometer, a synchro, a resolver, and/or an RVDT, among other examples.

[0064] The pump unit 300 may also include prime mover power and/or control components, such as a variable speed or frequency drive (VFD) 313 and/or an engine throttle control 315, which may be utilized to facilitate control of the prime mover 304 by the controller 410. The VFD 313/throttle control 315 may be connected with or otherwise in communication with the prime mover 304 via mechanical and/or electrical communication means 314. For example, the VFD 313 may receive control signals from the controller 410 and output corresponding electrical power to control the speed of the prime mover 304 and, thus, control the speed of the pump unit 300. The throttle control 315 may receive control signals from the controller 410 and output a corresponding electrical or mechanical throttle control signal to control the speed of the prime mover 304. Although the VFD 313/throttle control 315 is shown located near or in association with the prime mover 304, the VFD 313/throttle control 315 may be located or disposed at a distance from the prime mover 304. For example, the VFD 313/throttle control 315 may be or form a portion of the control/power center 130. The pump unit 300 may comprise the VFD 313 in implementations in which the prime mover 304 is or comprises an electric motor and the pump unit 300 may comprise the engine throttle control 315 in implementations in which the prime mover 304 is or comprises an engine.

[0065] The prime mover 304 may be cooled and/or lubricated by a lube pump unit 312 operatively coupled with the prime mover 304. The lube pump unit 312 may impart flow of lubricant through portions of the prime mover 304, such as to remove heat from the prime mover 304 and/or lubricate moving portions of the prime mover 304. The lube pump unit 312 may comprise a pump portion (not shown) and an actuator portion (not shown) operable to actuate the pump portion. The actuator portion of the lube pump unit 312 and, thus, the pumping operations of the lube pump unit 312 may be controlled and/or powered by the VFD 313, which may be connected with or otherwise in communication with the lube pump unit 312 via the communication means 314, such as electrical communication means. Functionality or operation of the lube pump unit 312 may be monitored or confirmed by monitoring lubricant pressure and/or lubricant flow rate generated by the lube pump unit 312. For example, the lubricant pressure and flow rate may be monitored by corresponding

pressure and flow rate sensors (not shown) disposed in association with the lube pump unit 312 and in communication with the controller 410.

[0066] The prime mover 304 may also or instead be cooled by a cooling fan assembly or blower unit 305 disposed in association with the prime mover 304. The blower unit 305 may impart air movement, such as to remove heat from the prime mover 304 or otherwise prevent the prime mover 304 from overheating. The blower unit 305 may also remove heat from the lubricant being pumped by the lube pump unit 312. The blower unit 305 may comprise a plurality of blades (not shown) and an actuator portion (not shown) operable to actuate the blades. The actuator portion of the blower unit 305 and, thus, the cooling operations of the blower unit 305 may be controlled and/or powered by the VFD 313. The VFD 313 may be connected with or otherwise in communication with the blower unit 305 via the communication means 314, such as electrical communication means. Functionality or operation of the blower unit 305 may be monitored or confirmed by monitoring air pressure and/or air flow rate generated by the blower unit 305. The air pressure and air flow rate may be monitored by corresponding pressure and flow rate sensors (not shown) disposed in association with the blower unit 305 and in communication with the controller 410.

[0067] A temperature sensor 307, such as a resistance temperature detector (RTD), may be disposed in association with the prime mover 304, such as to generate a signal or information indicative of a temperature of the prime mover 304. For example, the temperature sensor 307 may monitor the temperature within a motor winding, an engine housing, or within another portion of the prime mover 304. The temperature sensor 307 may be in communication with the controller 410, which may shut down the prime mover 304 if the detected temperature level exceeds a predetermined temperature level.

[0068] A moisture sensor 309 may also be disposed in association with the prime mover 304, such as to generate a signal or information indicative of moisture present at or near the prime mover 304. The moisture sensor 309 may be in communication with the controller 410, which may shut down the prime mover 304 if the moisture is detected by the moisture sensor 309.

[0069] Although FIGS. 3 and 4 show the pump unit 300 comprising a triplex reciprocating pump 302, which has three fluid chambers 318 and three reciprocating members 322, implementations within the scope of the present disclosure may include the pump 302 as or comprising a quintuplex reciprocating pump having five fluid chambers 318 and five reciprocating members 322, or a pump having other quantities of fluid chambers 318 and reciprocating members 322. It is further noted that the pump 302 described above and

shown in FIGS. 3 and 4 is merely an example, and that other pumps, such as diaphragm pumps, gear pumps, external circumferential pumps, internal circumferential pumps, lobe pumps, and other positive displacement pumps, are also within the scope of the present disclosure.

[0070] Various portions of the cementing unit 200 described above may collectively form a control system 400, which may be operable to monitor and/or control operations of the cementing unit 200, including the fluid pressure and fluid flow rate generated by the pump units 241, 242. FIG. 5 is a schematic view of a portion of an example implementation of a control system 400 according to one or more aspects of the present disclosure. The following description refers to FIGS. 1-5, collectively.

[0071] The control system 400 may include the controller 410 in communication with the valve actuators 251, 256, 266, 268, the position sensors 253, 260, 272, 274, the flow sensors 244, 245, 246, 247, the pressure sensors 276, 317, the transmission 362, the rotary sensor 311, the temperature sensor 307, the moisture sensor 309, the fluid level sensors 211, 213, 215, and the prime mover 304, the lube pump unit 312, and the blower unit 305 via the VFD 313/throttle control 315. For clarity, these and other components in communication with the controller 410 will be collectively referred to hereinafter as "sensors and controlled components." The controller 410 may be operable to execute example machine-readable instructions to implement at least a portion of one or more of the example methods and/or processes described herein, and/or to implement at least a portion of one or more of the example systems described herein.

[0072] The controller 410 may be or comprise, for example, one or more processors, special-purpose computing devices, servers, personal computers, personal digital assistant (PDA) devices, smartphones, internet appliances, and/or other types of computing devices. The controller 410 may comprise a processor 412, such as a general-purpose programmable processor. The processor 412 may comprise a local memory 414, and may execute coded instructions 432 present in the local memory 414 and/or another memory device. The processor 412 may execute, among other things, machine-readable instructions or programs to implement the example methods and/or processes described herein. The programs stored in the local memory 414 may include program instructions or computer program code that, when executed by an associated processor, facilitate the cementing unit 200 to perform the example methods and/or processes described herein. The processor 412 may be, comprise, or be implemented by one or a plurality of processors of various types suitable to the local application environment, and may include one or more of general-purpose computers,

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special-purpose computers, microprocessors, digital signal processors (DSPs), field-programmable gate arrays (FPGAs), application-specific integrated circuits (ASICs), and processors based on a multi-core processor architecture, as non-limiting examples. Of course, other processors from other families are also appropriate.

[0073] The processor 412 may be in communication with a main memory 417, such as may include a volatile memory 418 and a non-volatile memory 420, perhaps via a bus 422 and/or other communication means. The volatile memory 418 may be, comprise, or be implemented by random access memory (RAM), static random access memory (SRAM), synchronous dynamic random access memory (SDRAM), dynamic random access memory (DRAM), RAMBUS dynamic random access memory (RDRAM), and/or other types of random access memory devices. The non-volatile memory 420 may be, comprise, or be implemented by read-only memory, flash memory, and/or other types of memory devices. One or more memory controllers (not shown) may control access to the volatile memory 418 and/or non-volatile memory 420. The controller 410 may be operable to store or record information entered by the human operators and/or information generated by the sensors and controlled components on the main memory.

[0074] The controller 410 may also comprise an interface circuit 424. The interface circuit 424 may be, comprise, or be implemented by various types of standard interfaces, such as an Ethernet interface, a universal serial bus (USB), a third generation input/output (3GIO) interface, a wireless interface, and/or a cellular interface, among others. The interface circuit 424 may also comprise a graphics driver card. The interface circuit 424 may also comprise a communication device, such as a modem or network interface card to facilitate exchange of data with external computing devices via a network (*e.g.*, Ethernet connection, digital subscriber line (DSL), telephone line, coaxial cable, cellular telephone system, satellite, *etc.*). One or more of the sensors and controlled components may be connected with the controller 410 via the interface circuit 424, such as may facilitate communication between the sensors and controlled components and the controller 410.

[0075] One or more input devices 426 may also be connected to the interface circuit 424. The input devices 426 may permit the human operators to enter the coded instructions 432, operational set-points, and/or other data into the processor 412. The operational set-points may include, but not limited to, a pressure ramp set-point, a pressure set-point, a pressure duration set-point, flow rate ramp set-point, a flow rate set-point, a fluid volume set-point, pump unit operating speed set-point, among other examples. Additional operational set-points may be described below. The input devices 426 may be, comprise, or be implemented

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by a keyboard, a mouse, a touchscreen, a track-pad, a trackball, an isopoint, and/or a voice recognition system, among other examples. One or more output devices 428 may also be connected to the interface circuit 424. The output devices 428 may be, comprise, or be implemented by display devices (*e.g.*, a liquid crystal display (LCD) or cathode ray tube display (CRT), among others), printers, and/or speakers, among other examples. The controller 410 may also connect with one or more mass storage devices 430 and/or a removable storage medium 434, such as may be or include floppy disk drives, hard drive disks, compact disk (CD) drives, digital versatile disk (DVD) drives, and/or USB and/or other flash drives, among other examples.

[0076] The coded instructions 432, the operational set-points, and/or other data may be stored in the mass storage device 430, the main memory 417, the local memory 414, and/or the removable storage medium 434. Thus, the controller 410 may be implemented in accordance with hardware (perhaps implemented in one or more chips including an integrated circuit, such as an application specific integrated circuit), or may be implemented as software or firmware for execution by the processor 412. In the case of firmware or software, the implementation may be provided as a computer program product including a computer readable medium or storage structure embodying computer program code (*i.e.*, software or firmware) thereon for execution by the processor 412.

[0077] The coded instructions 432 may include program instructions or computer program code that, when executed by the processor 412, may cause the cementing unit 200 to perform methods, processes, and/or routines described herein. For example, the controller 410 may receive and process the operational set-points and/or the signals or information generated by the various sensors described herein. Based on the received operational set-points and sensor information, the controller 410 may cause the cementing unit 200 and/or other portions of the wellsite system 100 to automatically perform and/or undergo one or more operations or routines within the scope of the present disclosure. For example, the controller 410 may cause the cementing unit 200 to perform an initialization of the cementing unit 200, a pressure calibration of the cementing unit 200, a pressure test of the cementing unit 200, a flow rate calibration of the cementing unit 200, a flow rate test of the cementing unit 200, a cement pumping operation of the cementing unit 200, among other examples, substantially without manual control of the various portions of the cementing unit 200 by human operators. The controller 410 may also assess operational health of the cementing unit 200, including the pump units 241, 242, the fluid valves 221, 223, 225, 227, 237, 238, 239, 248, 249, 252, 262, 264, and the discharge manifold 250. Also, if a plurality of

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cementing units 200 are utilized at the wellsite 102 to perform a cementing job or operation, the controller 410 may receive information designating which one or more of the plurality of cementing units 200 may perform the operations or routines described herein.

[0078] The pressure and flow rate tests may be performed by the cementing unit 200 before the cement pumping operations. For example, the pressure test may permit an automated verification that the high pressure portions of the cementing unit 200, including the manifold 250 and the fluid valves 237, 238, 239, 248, 249, 252, 262, 264, are properly fastened and that there are no leaks that may cause safety or service quality issues during the cement pumping operation. The pressure test may also validate that the cementing unit 200 is functioning well enough to reach intended high pressures to perform the cement pumping operation. The flow rate test may validate that the cementing unit 200, including the pump units 241, 242, is functioning well enough to reach intended high flow rates that may be utilized during the cement pumping operation. The cement pumping operation may include automated pumping of the cement slurry into the wellbore 104 in a predetermined manner and at a predetermined flow rate and/or pressure.

[0079] The initialization of the cementing unit 200 may be performed before the cement pumping operation to verify that the cementing unit 200 may pump the cement slurry at the intended flow rate and measure the cement flow rate accurately. During or after the initialization, the flow rate calibration of the cementing unit 200 may be performed. The flow rate calibration may include the controller 410 executing the coded instructions 432 or an algorithm to sweep through various prime mover speed settings and/or transmission gear settings to generate a baseline for a database comprising data points correlating a particular operating speed of the cementing unit 200 and a resulting flow rate generated by the cementing unit 200. During flow rate calibration, the coded instructions 432 may cause the controller 410 to increase the output flow rate of the cementing unit 200 to automatically and continuously check for deviations from an expected baseline behavior and utilize feedback, feedforward, and ramping control to update the database with the optimal correlation of the various cementing unit pumping speeds. Accordingly, the flow rate calibration may provide an estimated flow rate ramp indicative of fluid flow rate generated by the cementing unit 200 in response or with respect to the operating or pumping speed of the cementing unit 200. Accordingly, the estimated flow rate ramp may be utilized by the controller 410 to automatically control the pumping speed of the cementing unit 200 by controlling the prime mover 304 and/or transmission 362 to control the flow rate of the cement or other fluid during the cement pumping operation and/or another pumping operation.

[0080] During the initialization of the cementing unit 200, the pressure calibration of the cementing unit 200, the pressure test of the cementing unit 200, the flow rate calibration of the cementing unit 200, the flow rate test of the cementing unit 200, and the cement pumping operation of the cementing unit 200, the cementing unit 200 may utilize the pump units 241, 242 to pump water, brine, mud, the base fluid, the mixed fluid, the cement slurry, and/or other fluids from the mixing tank 222, the displacement tanks 210, 212, and/or other sources, such as the tanks 112, the container 114, and/or the batch mixer 126. Accordingly, unless described otherwise, the one or more fluids being pumped by the pump units 241, 242, may be referred to hereinafter simply as "a fluid."

[0081] FIG. 6 is a flow-chart diagram of at least a portion of an example implementation of a method (500) according to one or more aspects of the present disclosure. The method (500) may be performed utilizing or otherwise in conjunction with at least a portion of one or more implementations of one or more instances of the apparatus shown in one or more of FIGS. 1-5 and/or otherwise within the scope of the present disclosure. For example, the method (500) may be performed and/or caused, at least partially, by the controller 410 executing the coded instructions 432 according to one or more aspects of the present disclosure. Thus, the following description of the method (500) also refers to apparatus shown in one or more of FIGS. 1-5. However, the method (500) may also be performed in conjunction with implementations of apparatus other than those depicted in FIGS. 1-5 that are also within the scope of the present disclosure.

[0082] The method (500) may comprise establishing (505) communication between the cementing unit 200 and the controller 410. As described above, the controller 410 is operable to control operation of the cementing unit 200, such as via operation of the processor 412, the memory 417, and the computer program code 432. The method (500) may further comprise inputting (510) operational set-points, such as may be utilized by the controller 410 to automatically perform a flow rate calibration and/or other operation of the cementing unit 200. Such inputs (510) may be performed by a human operator via the input devices 426 described above, although the controller 410 may also be operable to retrieve the inputs as predetermined values/ranges included in the computer program code 432.

[0083] The method (500) also comprises operating (515) the controller 410 to automatically perform initialization of operation of the cementing unit 200. The initialization may comprise automatically determining (520) operational parameters related to operational status of the cementing unit 200 based on the information generated by the sensors 253, 244, 276, 307, 309, 311, 317, and confirming (525) the operational parameters are within

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corresponding predetermined ranges. The operational parameters may comprise at least one of cementing unit temperature, cementing unit pressure, presence of moisture in association with the cementing unit, cementing unit cooling system pressure, and cementing unit lubrication system pressure, among other examples.

[0084] The determination (520) and confirmation (525) of the operational parameters may be or comprise a pre-calibration parameter condition check performed by the controller 410, such as may include monitoring the operational parameters or signals from the various sensors 253, 244, 276, 307, 309, 311, 317 and confirming that the detected operational parameters are within the corresponding predetermined ranges. If the detected parameters match or are within the predetermined parameters, pre-conditions are met and the initialization may continue. For example, the controller 410 may monitor the temperature sensor 307 to verify that the temperature of the prime mover 304 does not exceed a predetermined threshold. The controller 410 may also monitor the moisture sensor 309 to check if the prime mover 304 is exposed to moisture. If the temperature of the prime mover 304 is greater than, for example, 170 °Celsius (°C) or if the prime mover 304 is exposed to moisture, the initialization (515) may be stopped. The controller 410 may also monitor functionality of the lube pump unit 312 and/or the blower unit 305 by monitoring the lubricant and air pressure and/or flow rate.

[0085] The initialization and/or other portion of the method (500) may also comprise performing (530) the flow rate calibration and/or other operation utilizing the entered (510) operational set-points. The operational set-points may relate to at least one of a fluid volume to be pumped by the cementing unit 200 and a pumping speed of the cementing unit 200 during the performance (530) of the flow rate calibration and/or other operation.

[0086] For example, performing (530) the flow rate calibration may comprise varying (535) pumping speed of the cementing unit 200 while recording the pumping speed and a corresponding flow rate generated by the cementing unit, and estimating or otherwise determining (540) a flow rate ramp relating the flow rate to the pumping speed. The flow rate ramp may relate the recorded fluid flow rate generated by the cementing unit 200 to the recorded pumping speed or operating rate of the cementing unit 200. The flow rate ramp may be utilized as an estimate or projection of an actual fluid flow rate in response to the pumping speed during cement or other pumping operations. The flow rate ramp may be utilized during the cement pumping operations or other pumping operations to control the fluid flow rate by controlling the pumping speed of the cementing unit 200.

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[0087] Varying (535) the pumping speed may comprise increasing (545) the pumping speed of the cementing unit 200 while recording the pumping speed and the corresponding flow rate generated by the cementing unit until a predetermined fluid volume is pumped by the cementing unit 200. Varying (535) the pumping speed may further comprise decreasing (550) the pumping speed of the cementing unit 200 while recording the pumping speed and the corresponding flow rate generated by the cementing unit 200 until the cementing unit 200 stops pumping the fluid. Varying (535) the pumping speed of the cementing unit 200 may be performed by varying the speed of the prime mover 304 via the VFD/engine throttle 313, 315 and/or by shifting between lower and higher speeds or gear ratios of the transmission 362.

[0088] The pumping speed may be increased (545) by a first incremental speed set-point until the predetermined fluid volume is pumped, and the pumping speed may be decreased (550) by a second incremental speed set-point until the cementing unit 200 stops pumping the fluid. In an example implementation, the first and second incremental speed set-points may range between about one and about five revolutions per minute (RPM) for each flow rate and pumping speed reading performed by the controller 410. The predetermined fluid volume may range, for example, between about 50 barrels (BBL) and about 200 BBL of fluid.

[0089] Performing (530) the flow rate calibration may further comprise the controller 410, before varying the pumping speed, confirming that the cementing unit 200 has stopped pumping, confirming that the cementing unit 200 is depressurized, detecting a volume of fluid available for performing the flow rate calibration, and opening (and/or confirming to be open) fluid inlet valves 221, 223, 225, 227 and fluid outlet valves 238, 239 of the cementing unit 200. The controller 410 may confirm that the cementing unit 200 has stopped via the rotary sensors 311. The controller 410 may confirm that the cementing unit 200 is depressurized if the pressure detected by the pressure sensor 317 ranges, for example, between about zero and about 100 pounds per square inch (PSI). Furthermore, the controller 410 may confirm that the fluid volume available for performing the flow rate calibration is sufficient if, for example, the fluid level sensors 211, 213, 215 indicate between about 50 BBL and about 200 BBL of fluid. Also, the controller 410 may confirm that the fluid inlet valves 221, 223, 225, 227 and the fluid outlet valves 238, 239 are open via the valve position sensors 253.

[0090] The method (500) may further comprise operating the controller 410 to automatically confirm (555) that safety parameters are within corresponding predetermined ranges. Safety parameters may include pressure and temperature readings, which if exceeding the predetermined ranges, may cause the controller 410 to shut down the

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initialization. For example, a predetermined threshold of safety related to the prime mover 304 may be a temperature exceeding 170 °C. A predetermined threshold of safety related to the pump units 241, 242 may be a pressure exceeding 20,000 PSI or another pressure exceeding pump unit specifications. A sudden pressure drop detected, for example, within the pump units 241, 242 and/or the manifold 250 may be indicative of a leak or structural failure and may also cause the controller 410 to shut down the initialization. The automatic confirmation (555) that safety parameters are within corresponding predetermined ranges may be perform before, during, and/or after the initialization (515), the flow rate calibration (530), and/or other operations of the cementing unit 200.

[0091] FIG. 7 is a flow-chart diagram of at least a portion of an example implementation of another method (600) according to one or more aspects of the present disclosure. The method (600) may be performed utilizing or otherwise in conjunction with at least a portion of one or more implementations of one or more instances of the apparatus shown in one or more of FIGS. 1-5 and/or otherwise within the scope of the present disclosure. For example, the method (600) may be performed and/or caused, at least partially, by the controller 410 executing the coded instructions 432 according to one or more aspects of the present disclosure. Thus, the following description of the method (600) also refers to apparatus shown in one or more of FIGS. 1-5. However, the method (600) may also be performed in conjunction with implementations of apparatus other than those depicted in FIGS. 1-5 that are also within the scope of the present disclosure.

[0092] The method (600) may comprise establishing (605) communication between the cementing unit 200 and the controller 410. The method (600) also comprises operating (610) the controller 410 to automatically perform a flow rate calibration of the cementing unit 200. Automatically performing (610) the flow rate calibration may include automatically varying (615) the pumping speed of the cementing unit 200 while recording the pumping speed monitored by the rotary sensor 311 and a corresponding flow rate of the cementing unit 200 monitored by the flow sensors 244, 245, 246, 247. The pumping speed may be controlled by controlling the operating speed of the prime mover 304 and/or the gear settings of the transmission 362. A flow rate ramp relating the flow rate to the pumping speed is then estimated or otherwise determined (620) based on the recorded (615) data.

[0093] The method (600) may further include inputting (625) one or more operational set-points, such as a predetermined fluid volume to be pumped by the cementing unit 200. Such inputs (625) may be performed by a human operator via the input devices 426 described above, although the controller 410 may also be operable to retrieve the inputs as

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predetermined values/ranges included in the computer program code 432. Varying (615) the pumping speed may comprise increasing (630) the pumping speed while recording the pumping speed and the corresponding flow rate generated by the cementing unit 200 until the predetermined fluid volume or other operational set-point is met, and decreasing (635) the pumping speed of the cementing unit 200 while recording the pumping speed and the corresponding flow rate generated by the cementing unit 200 until the cementing unit 200 stops pumping a fluid. For example, the operational set-point may be a predetermined range of the fluid volume to be pumped by the cementing unit 200, such as between about 20 BBL and about 100 BBL of fluid, and/or between about 20% and about 30% of a fluid volume allocated for the performance (610) of the flow rate calibration.

[0094] The entered (625) set-points may also comprise first and second incremental speed set-points, such that the pumping speed may be increased (630) by the first incremental speed set-point until the operational set-point is met, and the pumping speed may be decreased (635) by the second incremental speed set-point until the cementing unit 200 stops pumping the fluid. For example, the first and second incremental speed set-points may range between about one and about five RPM for each flow rate and pumping speed recording (615) performed by the controller 410.

[0095] The entered (625) set-points may also comprise a first incremental percentage set-point, a second incremental percentage set-point, a fluid flow rate set-point, and a fluid volume set-point. For example, determining (620) the flow rate ramp may include determining a first flow rate ramp based on the data recorded (615) while increasing (630) and decreasing (635) the pumping speed, and varying (615) the pumping speed while recording data may further comprise increasing (640) the pumping speed by a speed corresponding to the first incremental percentage set-point of the fluid flow rate set-point based on the first flow rate ramp while recording the pumping speed monitored by the rotary sensor 311 and the corresponding flow rate of the cementing unit 200 monitored by the flow sensors 244, 245, 246, 247 until the fluid volume set-point is met. Varying (615) the pumping speed may further comprise decreasing (645) the pumping speed by a speed corresponding to the second incremental percentage set-point of the fluid flow rate set-point based on the first flow rate ramp while recording the pumping speed monitored by the rotary sensor 311 and a corresponding flow rate of the cementing unit 200 monitored by the flow sensors 244, 245, 246, 247 until the cementing unit stops pumping the fluid. Determining (620) the flow rate ramp(s) may thus also comprise determining a second flow rate ramp relating the flow rate to the pumping speed after the first flow rate ramp was estimated, based

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on the data recorded (615) during the second pump speed increase (640) and/or decrease (645) and/or the first flow rate ramp.

[0096] Similarly to the first flow rate ramp, the second flow rate ramp may relate the recorded fluid flow rate to the recorded pumping speed. However, in determining (620) the second flow rate ramp, the controller 410 may cause the cementing unit 200 to increase (640) and then decrease (645) by the first and second incremental percentage set-points of the fluid flow rate set-point. Accordingly, the controller 410 may increase (640) and decrease (645) the flow rate of the cementing unit 200 by the incremental percentage set-points by increasing and decreasing the operating speed of the cementing unit 200 by a speed that corresponds to the incremental percentage set-point of the fluid flow rate set-point based on the first flow rate ramp.

[0097] In an example implementation, the first and second incremental percentage set-points may each range between about 1% and about 10% of the fluid flow rate set-point. The fluid flow rate set-point may range, for example, between about four BBL per minute (BPM) and about ten BPM. The fluid volume set-point may range between about 50 BBL and about 200 BBL of fluid. The fluid volume set-point may instead range, for example, between about 70% and about 80% of the fluid volume allocated for performance (610) of the flow rate calibration.

[0098] Similarly to as described above with respect to performing (530) the flow rate calibration of the method (500) shown in FIG. 6, performing (610) the flow rate calibration may further comprise, before varying (615) the pumping speed, confirming that the cementing unit 200 has stopped pumping, confirming that the cementing unit 200 is depressurized, detecting a volume of fluid available for the performance (610) of the flow rate calibration, and opening the fluid inlet valves 221, 223, 225, 227 and fluid outlet valves 238, 239 of the cementing unit 200. The method (600) may also comprise operating the controller 410 to automatically confirm (650) that safety parameters are within corresponding predetermined ranges before, during, and/or after the performance (610) of the flow rate calibration, such as before, during, and/or after varying (615) the pumping speed while recording data as described above.

[0099] FIG. 8 is a flow-chart diagram of at least a portion of an example implementation of another method (700) according to one or more aspects of the present disclosure. The method (700) may be performed utilizing or otherwise in conjunction with at least a portion of one or more implementations of one or more instances of the apparatus shown in one or more of FIGS. 1-5 and/or otherwise within the scope of the present disclosure. For example,

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the method (700) may be performed and/or caused, at least partially, by the controller 410 executing the coded instructions 432 according to one or more aspects of the present disclosure. Thus, the following description of the method (700) also refers to apparatus shown in one or more of FIGS. 1-5. However, the method (700) may also be performed in conjunction with implementations of apparatus other than those depicted in FIGS. 1-5 that are also within the scope of the present disclosure.

[00100] The method (700) may comprise establishing (705) communication between the cementing unit 200 and the controller 410. The method (700) may also comprise inputting (710) one or more set-points. For example, an input (710) set-point may be a fluid volume set-point, such as may range between about 50 BBL and about 500 BBL of fluid, although other values/ranges are also within the scope of the present disclosure. The inputs (710) may be performed by a human operator via the input devices 426 described above, although the controller 410 may also be operable to retrieve the inputs as predetermined values/ranges included in the computer program code 432.

[00101] The method also comprises operating (715) the controller 410 to automatically perform a cement pumping operation of the cementing unit 200. Performing (715) the cement pumping operation may comprise automatically increasing (720) pumping speed of the cementing unit 200 while recording the pumping speed, the pressure generated by the cementing unit 200 corresponding to the pumping speed, and the cement flow rate corresponding to the pumping speed and/or pressure. Performing (715) the cement pumping operation may then comprise automatically maintaining (725) the pumping speed while recording the pumping speed and the corresponding pressure and cement flow rate, and then decreasing (730) the pumping speed while recording the pumping speed and the corresponding pressure and cement flow rate until the cementing unit 200 has stopped pumping cement and the volume of the pumped cement is substantially equal to the fluid volume set-point.

[00102] The input (710) set-points may also comprise a fluid flow rate set-point. For example, the cement pumping operation (715) may comprise increasing (720) pumping speed to reach the flow rate set-point and maintaining (725) the pumping speed to maintain the fluid flow rate set-point. The fluid flow rate set-point may range, for example, between about four BPM and about ten BPM. The fluid flow rate may be increased (720) and decreased (730), for example, at a rate ranging between about 0.50 BPM/minute and about 5 BPM/minute.

[00103] Similarly to as described above with respect to the method (500), operation (715) of the controller 410 for the cementing operation may further comprise, before increasing

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(720), maintaining (725), and decreasing (730) the pumping speed, confirming that the cementing unit 200 has stopped pumping and is depressurized, confirming that a volume of fluid is available for performing the cement pumping operation, and opening (and/or confirming to be open) the fluid inlet valves 221, 223, 225, 227 and fluid outlet valves 238, 239 of the cementing unit 200.

[00104] The method (700) may also comprise operating (750) the controller 410 to initialize the cementing unit 200, as described above with respect to FIG. 6. The method (700) may also comprise confirming (760) that safety parameters are within predetermined ranges, similar to as described above. Such confirmation (760) may be performed before, during, and/or after the initialization (750) and/or the cementing operation (715). For example, such confirmation (760) may be or comprise a pre-calibration parameter condition check performed by the controller 410, such as may include monitoring the operational parameters or signals from the various sensors 253, 244, 276, 307, 309, 311, 317 and confirming that the detected operational parameters are within the corresponding predetermined ranges. If the detected parameters match the predetermined parameters, pre-conditions are met and the cementing operation (715) may continue.

[00105] FIG. 9 is a flow-chart diagram of at least a portion of an example implementation of another method (800) according to one or more aspects of the present disclosure. The method (800) may be performed utilizing or otherwise in conjunction with at least a portion of one or more implementations of one or more instances of the apparatus shown in one or more of FIGS. 1-5 and/or otherwise within the scope of the present disclosure. For example, the method (800) may be performed and/or caused, at least partially, by the controller 410 executing the coded instructions 432 according to one or more aspects of the present disclosure. Thus, the following description of the method (800) also refers to apparatus shown in one or more of FIGS. 1-5. However, the method (800) may also be performed in conjunction with implementations of apparatus other than those depicted in FIGS. 1-5 that are also within the scope of the present disclosure.

[00106] The method (800) may comprise establishing (805) communication between the cementing unit 200 and the controller 410. The method (800) may also comprise inputting (810) one or more set-points. For example, an input (810) set-point may be a fluid volume set-point and/or a flow rate set-point, as described above. The inputs (810) may be performed by a human operator via the input devices 426 described above, although the controller 410 may also be operable to retrieve the inputs as predetermined values/ranges included in the computer program code 432.

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[00107] The method (800) also comprises operating the controller 410 to automatically initialize (815) the cementing unit 200 and perform (820) a cementing operation utilizing the cementing unit 200. Initializing (815) the cementing unit 200 may be via the method (500) shown in FIG. 6, or at least portions thereof. Performing (820) the cementing operation may be via the method (700) shown in FIG. 8, or at least portions thereof. The method (800) may also comprise operating the controller 410 to perform (825) a flow rate calibration of the cementing unit 200. The flow rate calibration (825) may be via the method (600) shown in FIG. 7, or at least portions thereof. The method (800) may also comprise confirming (830) that safety parameters are within predetermined ranges, similar to as described above. Other implementations of the method (800) shown in FIG. 9 also within the scope of the present disclosure may comprise other combinations of one or more aspects of two or more of the method (500) shown in FIG. 6, the method (600) shown in FIG. 7, and/or the method (700) shown in FIG. 8.

[00108] In view of the entirety of the present disclosure, including the claims and the figures, a person having ordinary skill in the art will readily recognize that the present disclosure introduces a method comprising: (A) establishing communication between a cementing unit and a controller operable to control operation of the cementing unit, wherein the controller comprises a processor and a memory including computer program code; (B) inputting a fluid volume set-point; and (C) operating the controller to automatically perform: (1) a flow rate calibration of the cementing unit, wherein the flow rate calibration comprises automatically: (a) varying pumping speed of the cementing unit while recording first pumping speeds and corresponding first flow rates generated by the cementing unit; and (b) determining a flow rate ramp relating the recorded first flow rates to the corresponding recorded first pumping speeds; and then (2) a cement pumping operation of the cementing unit, wherein the cement pumping operation comprises automatically: (a) increasing pumping speed of the cementing unit while recording: (i) second pumping speeds; (ii) first pressures generated by the cementing unit corresponding to the recorded second pumping speeds; and (iii) second flow rates generated by the cementing unit corresponding to the recorded second pumping speeds and/or first pressures; then (b) maintaining the pumping speed while recording the maintained pumping speed and corresponding second pressures and third flow rates; and then (c) decreasing the pumping speed while recording fourth pumping speeds and corresponding third pressures and fourth flow rates until the cementing unit has stopped pumping cement and a volume of the pumped cement is substantially equal to the fluid volume set-point.

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[00109] The method may further comprise inputting an operational set-point, and varying the pumping speed may comprise: increasing pumping speed of the cementing unit while recording the first pumping speeds and the corresponding first flow rates generated by the cementing unit until the operational set-point is met; and decreasing pumping speed of the cementing unit while recording the first pumping speeds and the corresponding first flow rates generated by the cementing unit until the cementing unit stops pumping a fluid. The operational set-point may comprise a predetermined fluid volume to be pumped by the cementing unit. The method may further comprise inputting first and second incremental speed set-points, wherein the pumping speed may be increased during the flow rate calibration by the first incremental speed set-point until the operational set-point is met, and wherein the pumping speed may be decreased during the flow rate calibration by the second incremental speed set-point until the cementing unit stops pumping the fluid.

[00110] The method may further comprise inputting a fluid flow rate set-point, wherein: increasing pumping speed of the cementing unit may comprise increasing pumping speed of the cementing unit to reach the flow rate set-point; and maintaining the pumping speed may comprise maintaining the pumping speed to maintain the fluid flow rate set-point.

[00111] The cementing unit may comprise a plurality of sensors operable to generate information related to operational status of the cementing unit. In such implementations, among others within the scope of the present disclosure, operating the controller may further comprise operating the controller to automatically perform initialization of operation of the cementing unit prior to the flow rate calibration. The initialization may comprise automatically: determining operational parameters related to the cementing unit operational status based on the information generated by the sensors; and confirming the operational parameters are within corresponding predetermined ranges.

[00112] The present disclosure also introduces a method comprising: (A) establishing communication between a cementing unit and a controller operable to control operation of the cementing unit, wherein the cementing unit comprises a plurality of sensors operable to generate information related to operational status of the cementing unit, and wherein the controller comprises a processor and a memory including computer program code; (B) operating the controller to automatically perform initialization of the cementing unit, wherein the initialization comprises automatically: (1) determining operational parameters related to the cementing unit operational status based on the information generated by the sensors; and (2) confirming the operational parameters are within corresponding predetermined ranges.

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[00113] The operational parameters may comprise at least one of cementing unit temperature, cementing unit pressure, presence of moisture in association with the cementing unit, cementing unit cooling system pressure, and cementing unit lubrication system pressure.

[00114] The method may further comprise inputting operational set-points to be utilized by the controller to automatically perform an operation of the cementing unit, wherein the initialization further comprises, after confirming the operational parameters are within the corresponding predetermined ranges, automatically performing a flow rate calibration utilizing the operational set-points. The operational set-points may relate to at least one of a fluid volume to be pumped by the cementing unit and a pumping speed of the cementing unit. The flow rate calibration may comprise: varying pumping speed of the cementing unit while recording the pumping speed and a corresponding flow rate generated by the cementing unit; and determining a flow rate ramp relating the recorded flow rates to the corresponding recorded pumping speeds. Varying the pumping speed may comprise: increasing the pumping speed of the cementing unit while recording the pumping speed and the corresponding flow rate generated by the cementing unit until a predetermined fluid volume is pumped by the cementing unit; and decreasing the pumping speed of the cementing unit while recording the pumping speed and the corresponding flow rate generated by the cementing unit until the cementing unit stops pumping the fluid. The pumping speed may be increased by a first incremental speed set-point until the predetermined fluid volume is pumped, and the pumping speed may be decreased by a second incremental speed set-point until the cementing unit stops pumping the fluid. The flow rate calibration may further comprise, before varying the pumping speed: confirming that the cementing unit is not pumping; confirming that the cementing unit is depressurized; confirming that a sufficient volume of fluid is available for performing the flow rate calibration; and either: (1) opening fluid inlet and outlet valves of the cementing unit; or (2) confirming that the fluid inlet and outlet valves of the cementing unit are open. The flow rate calibration may comprise each of: (1) opening the fluid inlet and outlet valves of the cementing unit; and (2) confirming that the fluid inlet and outlet valves of the cementing unit are open.

[00115] The method may further comprise operating the controller to automatically confirm that safety parameters are within corresponding predetermined ranges during the initialization.

[00116] The present disclosure also introduces a method comprising: (A) establishing communication between a cementing unit and a controller operable to control operation of the cementing unit, wherein the controller comprises a processor and a memory including

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computer program code; and (B) operating the controller to automatically perform a flow rate calibration of the cementing unit, wherein the flow rate calibration comprises automatically: (1) varying pumping speed of the cementing unit while recording the pumping speed and a corresponding flow rate generated by the cementing unit; and (2) determining a flow rate ramp relating the recorded flow rates to the corresponding recorded pumping speeds.

[00117] The method may further comprise inputting an operational set-point, and varying the pumping speed may comprise: increasing the pumping speed of the cementing unit while recording the pumping speed and the corresponding flow rate generated by the cementing unit until the operational set-point is met; and decreasing the pumping speed of the cementing unit while recording the pumping speed and the corresponding flow rate generated by the cementing unit until the cementing unit stops pumping a fluid. The operational set-point may comprise a predetermined fluid volume to be pumped by the cementing unit. The method may further comprise inputting first and second incremental speed set-points, wherein the pumping speed may be increased by the first incremental speed set-point until the operational set-point is met, and wherein the pumping speed may be decreased by the second incremental speed set-point until the cementing unit stops pumping the fluid. In such implementations, among others within the scope of the present disclosure, the recorded flow rates and corresponding recorded pumping speeds may be first recorded flow rates and first recorded pumping speeds; the flow rate ramp may be a first flow rate ramp; the method may further comprise inputting a first incremental percentage set-point, a second incremental percentage set-point, a fluid flow rate set-point, and a fluid volume set-point; and varying the pumping speed may further comprise, after estimating the first flow rate ramp: (a) increasing the pumping speed of the cementing unit by a speed corresponding to the first incremental percentage set-point of the fluid flow rate set-point based on the first flow rate ramp while recording second pumping speeds and corresponding second flow rates generated by the cementing unit until the fluid volume set-point is met; (b) decreasing the pumping speed of the cementing unit by a speed corresponding to the second incremental percentage set-point of the fluid flow rate set-point based on the first flow rate ramp while recording third pumping speeds and corresponding third flow rates generated by the cementing unit until the cementing unit stops pumping the fluid; and (c) determining a second flow rate ramp relating the second and third recorded flow rates to the corresponding second and third recorded pumping speeds.

[00118] The flow rate calibration may further comprise, before varying the pumping speed: (3) confirming that the cementing unit is not pumping; (4) confirming that the

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cementing unit is depressurized; (5) confirming that a sufficient volume of fluid is available for performing the flow rate calibration; and (6) either or both of: (i) opening fluid inlet and outlet valves of the cementing unit; or (ii) confirming that the fluid inlet and outlet valves of the cementing unit are open.

[00119] The method may further comprise operating the controller to automatically confirm that safety parameters are within corresponding predetermined ranges during the flow rate calibration.

[00120] The present disclosure also introduces a method comprising: (A) establishing communication between a cementing unit and a controller operable to control operation of the cementing unit, wherein the controller comprises a processor and a memory including computer program code; (B) inputting a fluid volume set-point; and (C) operating the controller to automatically perform a cement pumping operation of the cementing unit, wherein the cement pumping operation comprises automatically: (1) increasing pumping speed of the cementing unit while recording the pumping speed, pressure generated by the cementing unit and corresponding to the pumping speed, and cement flow rate generated by the cementing unit and corresponding to the pumping speed and/or pressure; then (2) maintaining the pumping speed while recording the pumping speed and the corresponding pressure and cement flow rate; and then (3) decreasing the pumping speed while recording the pumping speed and the corresponding pressure and cement flow rate until the cementing unit has stopped pumping cement and a volume of the pumped cement is substantially equal to the fluid volume set-point.

[00121] The method may further comprise inputting a fluid flow rate set-point, and the cement pumping operation may further comprise: increasing pumping speed of the cementing unit to reach the flow rate set-point; and maintaining the pumping speed to maintain the fluid flow rate set-point.

[00122] The cementing unit may further comprise a plurality of sensors operable to generate information related to operational status of the cementing unit, and the method may further comprise: determining operational parameters related to the cementing unit operational status based on the information generated by the sensors; and confirming that the operational parameters are within corresponding predetermined ranges.

[00123] The cement pumping operation may further comprise performing a flow rate calibration of the cementing unit before increasing, maintaining, and decreasing the pumping speed, wherein the flow rate calibration comprises automatically: varying pumping speed of the cementing unit while recording the pumping speed and a corresponding flow rate

generated by the cementing unit; and determining a flow rate ramp relating the recorded flow rates to the corresponding recorded pumping speeds. The flow rate calibration may further comprise, before varying the pumping speed: confirming that the cementing unit is not pumping; confirming that the cementing unit is depressurized; confirming that a sufficient volume of fluid is available for performing the flow rate calibration; and either or both of: opening fluid inlet and outlet valves of the cementing unit; or confirming that the fluid inlet and outlet valves of the cementing unit are open.

[00124] The method may further comprise operating the controller to automatically confirm that safety parameters are within corresponding predetermined ranges during the cement pumping operation.

[00125] The present disclosure also introduces apparatus operable to perform: the methods described above; one or more of such methods; one or more aspects of such methods; and/or other methods within the scope of the present disclosure.

[00126] The foregoing outlines features of several embodiments so that a person having ordinary skill in the art may better understand the aspects of the present disclosure. A person having ordinary skill in the art should appreciate that they may readily use the present disclosure as a basis for designing or modifying other processes and structures for carrying out the same purposes and/or achieving the same advantages of the embodiments introduced herein. A person having ordinary skill in the art should also realize that such equivalent constructions do not depart from the scope of the present disclosure, and that they may make various changes, substitutions and alterations herein without departing from the spirit and scope of the present disclosure.

[00127] The Abstract at the end of this disclosure is provided to comply with 37 C.F.R. §1.72(b) to allow the reader to quickly ascertain the nature of the technical disclosure. It is submitted with the understanding that it will not be used to interpret or limit the scope or meaning of the claims.

WHAT IS CLAIMED IS:

1. A method comprising:

establishing communication between a cementing unit and a controller operable to control operation of the cementing unit, wherein the controller comprises a processor and a memory including computer program code;

inputting a fluid volume set-point; and

operating the controller to automatically perform:

a flow rate calibration of the cementing unit, wherein the flow rate calibration comprises automatically:

varying pumping speed of the cementing unit while recording first pumping speeds and corresponding first flow rates generated by the cementing unit; and

determining a flow rate ramp relating the recorded first flow rates to the corresponding recorded first pumping speeds; and then

a cement pumping operation of the cementing unit, wherein the cement pumping operation comprises automatically:

increasing pumping speed of the cementing unit while recording:

second pumping speeds;

first pressures generated by the cementing unit corresponding to the recorded second pumping speeds; and

second flow rates generated by the cementing unit corresponding to the recorded second pumping speeds and/or first pressures; then

maintaining the pumping speed while recording the maintained pumping speed and corresponding second pressures and third flow rates; and then

decreasing the pumping speed while recording fourth pumping speeds and corresponding third pressures and fourth flow rates until the cementing unit has stopped pumping cement and a volume of the pumped cement is substantially equal to the fluid volume set-point.

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2. The method of claim 1 further comprising inputting an operational set-point, and wherein varying the pumping speed comprises:

increasing pumping speed of the cementing unit while recording the first pumping speeds and the corresponding first flow rates generated by the cementing unit until the operational set-point is met; and

decreasing pumping speed of the cementing unit while recording the first pumping speeds and the corresponding first flow rates generated by the cementing unit until the cementing unit stops pumping a fluid.

3. The method of claim 2 wherein the operational set-point comprises a predetermined fluid volume to be pumped by the cementing unit.

4. The method of claim 2 further comprising inputting first and second incremental speed set-points, wherein the pumping speed is increased during the flow rate calibration by the first incremental speed set-point until the operational set-point is met, and wherein the pumping speed is decreased during the flow rate calibration by the second incremental speed set-point until the cementing unit stops pumping the fluid.

5. The method of claim 1 further comprising inputting a fluid flow rate set-point, wherein:

increasing pumping speed of the cementing unit comprises increasing pumping speed of the cementing unit to reach the flow rate set-point; and

maintaining the pumping speed comprises maintaining the pumping speed to maintain the fluid flow rate set-point.

6. The method of claim 1 wherein:

the cementing unit comprises a plurality of sensors operable to generate information related to operational status of the cementing unit; and

operating the controller further comprises operating the controller to automatically perform initialization of operation of the cementing unit prior to the flow rate calibration, wherein the initialization comprises automatically:

determining operational parameters related to the cementing unit operational status based on the information generated by the sensors; and

confirming the operational parameters are within corresponding predetermined ranges.

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7. A method comprising:

establishing communication between a cementing unit and a controller operable to control operation of the cementing unit, wherein the cementing unit comprises a plurality of sensors operable to generate information related to operational status of the cementing unit, and wherein the controller comprises a processor and a memory including computer program code;

operating the controller to automatically perform initialization of the cementing unit, wherein the initialization comprises automatically:

determining operational parameters related to the cementing unit operational status based on the information generated by the sensors; and

confirming the operational parameters are within corresponding predetermined ranges.

8. The method of claim 7 wherein the operational parameters comprise at least one of cementing unit temperature, cementing unit pressure, presence of moisture in association with the cementing unit, cementing unit cooling system pressure, and cementing unit lubrication system pressure.

9. The method of claim 7 further comprising inputting operational set-points to be utilized by the controller to automatically perform an operation of the cementing unit, wherein the initialization further comprises, after confirming the operational parameters are within the corresponding predetermined ranges, automatically performing a flow rate calibration utilizing the operational set-points.

10. The method of claim 9 wherein the operational set-points relate to at least one of a fluid volume to be pumped by the cementing unit and a pumping speed of the cementing unit.

11. The method of claim 9 wherein the flow rate calibration comprises:

varying pumping speed of the cementing unit while recording the pumping speed and a corresponding flow rate generated by the cementing unit; and

determining a flow rate ramp relating the recorded flow rates to the corresponding recorded pumping speeds.

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12. The method of claim 11 wherein varying the pumping speed comprises:

increasing the pumping speed of the cementing unit while recording the pumping speed and the corresponding flow rate generated by the cementing unit until a predetermined fluid volume is pumped by the cementing unit; and

decreasing the pumping speed of the cementing unit while recording the pumping speed and the corresponding flow rate generated by the cementing unit until the cementing unit stops pumping the fluid.

13. The method of claim 12 wherein the pumping speed is increased by a first incremental speed set-point until the predetermined fluid volume is pumped, and wherein the pumping speed is decreased by a second incremental speed set-point until the cementing unit stops pumping the fluid.

14. The method of claim 11 wherein the flow rate calibration further comprises, before varying the pumping speed:

confirming that the cementing unit is not pumping;

confirming that the cementing unit is depressurized;

confirming that a sufficient volume of fluid is available for performing the flow rate calibration; and

either:

opening fluid inlet and outlet valves of the cementing unit; or

confirming that the fluid inlet and outlet valves of the cementing unit are open.

15. The method of claim 7 further comprising operating the controller to automatically confirm that safety parameters are within corresponding predetermined ranges during the initialization.

16. A method comprising:

establishing communication between a cementing unit and a controller operable to control operation of the cementing unit, wherein the controller comprises a processor and a memory including computer program code; and

operating the controller to automatically perform a flow rate calibration of the cementing unit, wherein the flow rate calibration comprises automatically:

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varying pumping speed of the cementing unit while recording the pumping speed and a corresponding flow rate generated by the cementing unit; and

determining a flow rate ramp relating the recorded flow rates to the corresponding recorded pumping speeds.

17. The method of claim 16 further comprising inputting an operational set-point, and wherein varying the pumping speed comprises:

increasing the pumping speed of the cementing unit while recording the pumping speed and the corresponding flow rate generated by the cementing unit until the operational set-point is met; and

decreasing the pumping speed of the cementing unit while recording the pumping speed and the corresponding flow rate generated by the cementing unit until the cementing unit stops pumping a fluid.

18. The method of claim 17 wherein the operational set-point comprises a predetermined fluid volume to be pumped by the cementing unit.

19. The method of claim 17 further comprising inputting first and second incremental speed set-points, wherein the pumping speed is increased by the first incremental speed set-point until the operational set-point is met, and wherein the pumping speed is decreased by the second incremental speed set-point until the cementing unit stops pumping the fluid.

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20. The method of claim 19 wherein:

the recorded flow rates and corresponding recorded pumping speeds are first recorded flow rates and first recorded pumping speeds;

the flow rate ramp is a first flow rate ramp;

the method further comprises inputting a first incremental percentage set-point, a second incremental percentage set-point, a fluid flow rate set-point, and a fluid volume set-point; and

varying the pumping speed further comprises, after estimating the first flow rate ramp:

increasing the pumping speed of the cementing unit by a speed corresponding to the first incremental percentage set-point of the fluid flow rate set-point based on the first flow rate ramp while recording second pumping speeds and corresponding second flow rates generated by the cementing unit until the fluid volume set-point is met;

decreasing the pumping speed of the cementing unit by a speed corresponding to the second incremental percentage set-point of the fluid flow rate set-point based on the first flow rate ramp while recording third pumping speeds and corresponding third flow rates generated by the cementing unit until the cementing unit stops pumping the fluid; and

determining a second flow rate ramp relating the second and third recorded flow rates to the corresponding second and third recorded pumping speeds.

21. The method of claim 16 wherein the flow rate calibration further comprises, before varying the pumping speed:

confirming that the cementing unit is not pumping;

confirming that the cementing unit is depressurized;

confirming that a sufficient volume of fluid is available for performing the flow rate calibration; and

either:

opening fluid inlet and outlet valves of the cementing unit; or

confirming that the fluid inlet and outlet valves of the cementing unit are open.

22. The method of claim 16 further comprising operating the controller to automatically confirm that safety parameters are within corresponding predetermined ranges during the flow rate calibration.

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23. A method comprising:

establishing communication between a cementing unit and a controller operable to control operation of the cementing unit, wherein the controller comprises a processor and a memory including computer program code;

inputting a fluid volume set-point; and

operating the controller to automatically perform a cement pumping operation of the cementing unit, wherein the cement pumping operation comprises automatically:

increasing pumping speed of the cementing unit while recording:

the pumping speed;

pressure generated by the cementing unit and corresponding to the pumping speed; and

cement flow rate generated by the cementing unit and corresponding to the pumping speed and/or pressure; then

maintaining the pumping speed while recording the pumping speed and the corresponding pressure and cement flow rate; and then

decreasing the pumping speed while recording the pumping speed and the corresponding pressure and cement flow rate until the cementing unit has stopped pumping cement and a volume of the pumped cement is substantially equal to the fluid volume set-point.

24. The method of claim 23 further comprising inputting a fluid flow rate set-point, and wherein the cement pumping operation further comprises:

increasing pumping speed of the cementing unit to reach the flow rate set-point; and

maintaining the pumping speed to maintain the fluid flow rate set-point.

25. The method of claim 23 wherein the cementing unit further comprises a plurality of sensors operable to generate information related to operational status of the cementing unit, and wherein the method further comprises:

determining operational parameters related to the cementing unit operational status based on the information generated by the sensors; and

confirming that the operational parameters are within corresponding predetermined ranges.

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26. The method of claim 23 wherein the cement pumping operation further comprises performing a flow rate calibration of the cementing unit before increasing, maintaining, and decreasing the pumping speed, wherein the flow rate calibration comprises automatically:

varying pumping speed of the cementing unit while recording the pumping speed and a corresponding flow rate generated by the cementing unit; and

determining a flow rate ramp relating the recorded flow rates to the corresponding recorded pumping speeds.

27. The method of claim 26 wherein the flow rate calibration further comprises, before varying the pumping speed:

confirming that the cementing unit is not pumping;

confirming that the cementing unit is depressurized;

confirming that a sufficient volume of fluid is available for performing the flow rate calibration; and

either:

opening fluid inlet and outlet valves of the cementing unit; or

confirming that the fluid inlet and outlet valves of the cementing unit are open.

28. The method of claim 23 further comprising operating the controller to automatically confirm that safety parameters are within corresponding predetermined ranges during the cement pumping operation.

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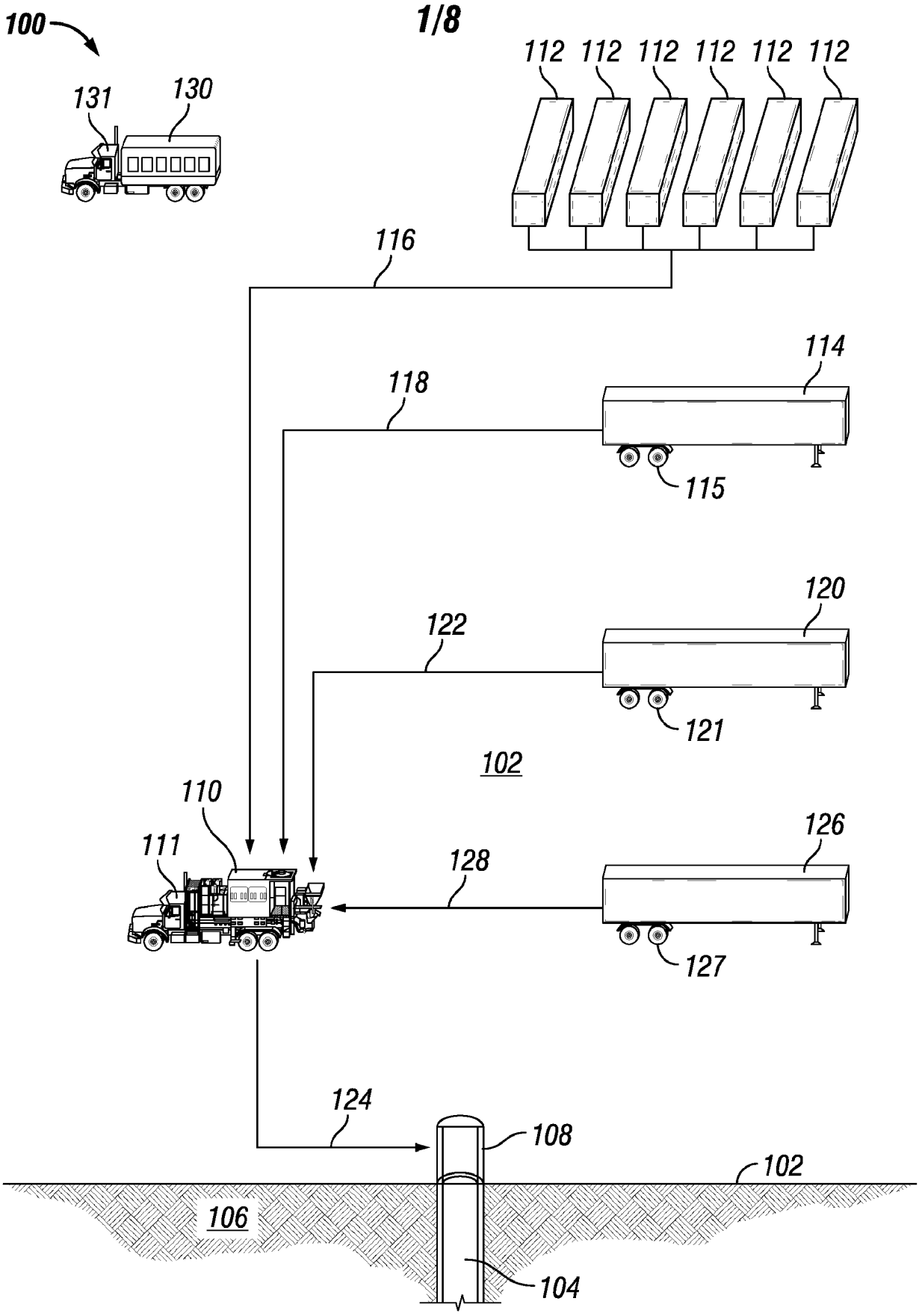

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FIG. 1

SUBSTITUTE SHEET (RULE 26)

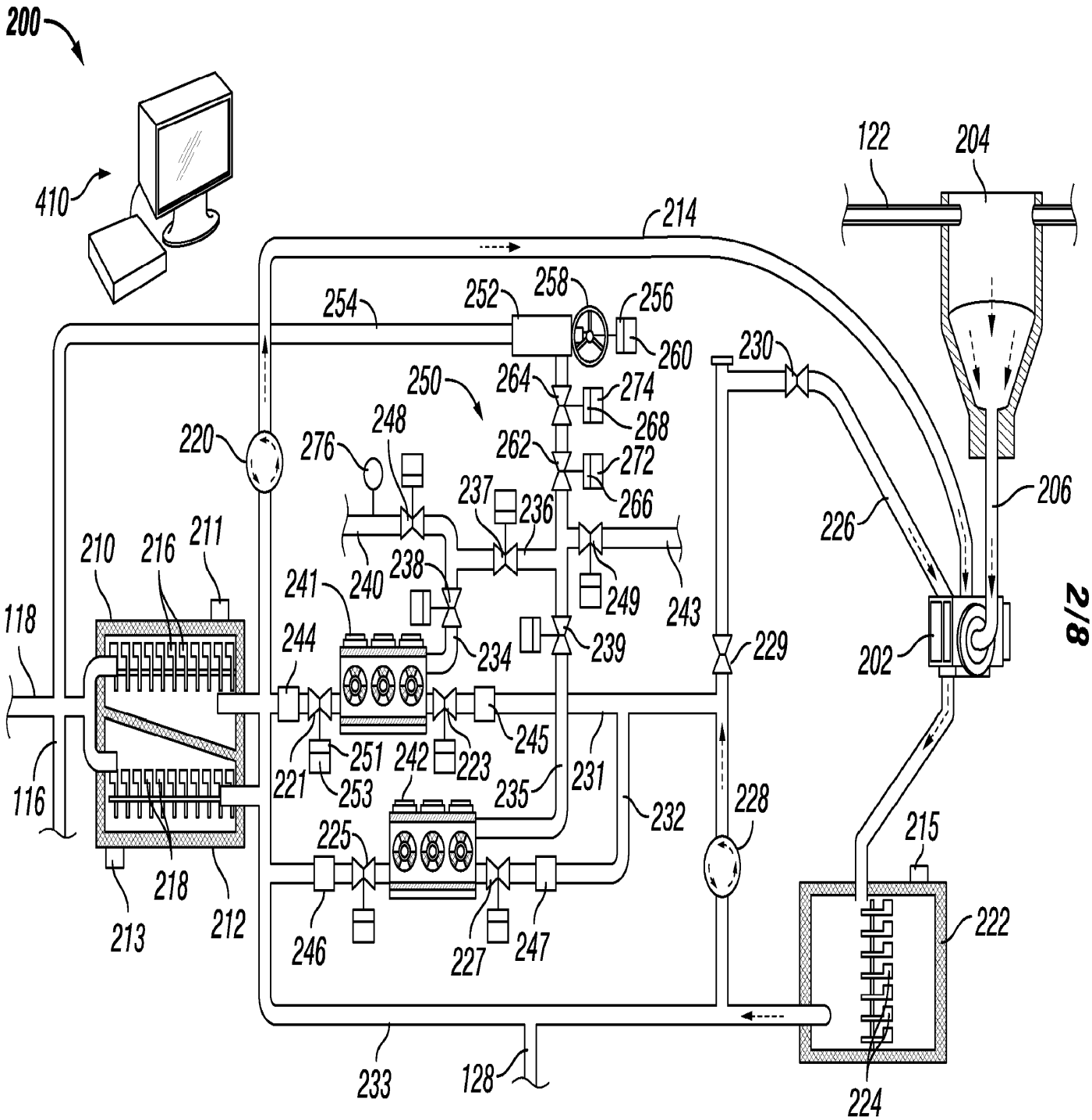


FIG. 2

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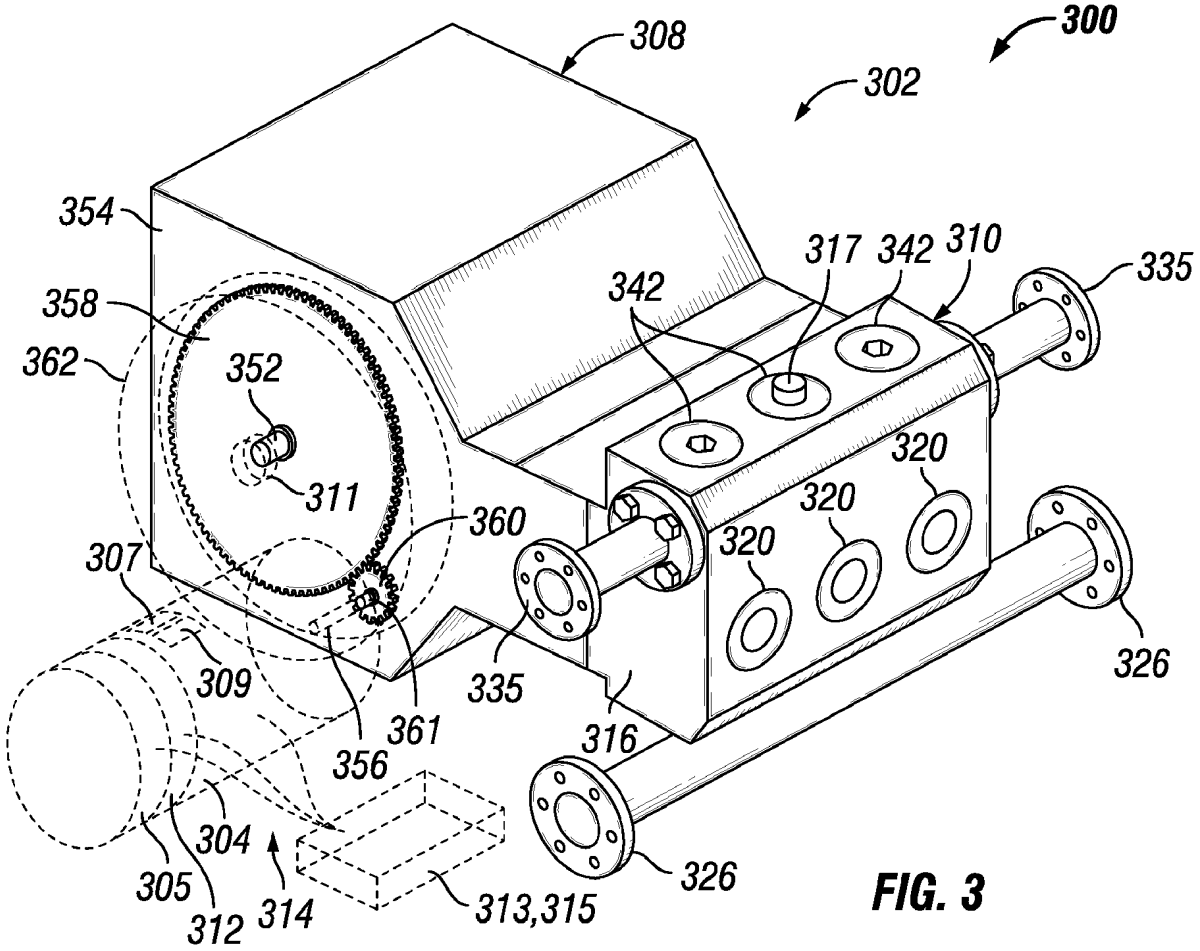

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FIG. 3

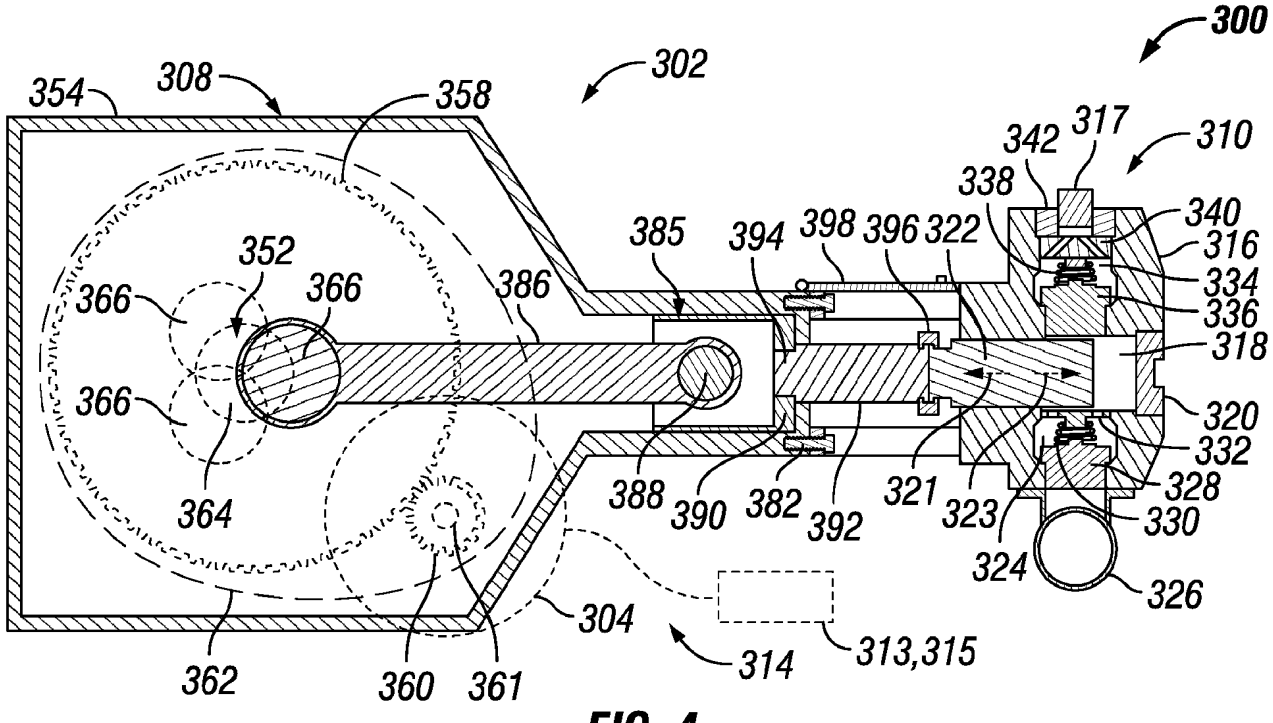

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FIG. 4

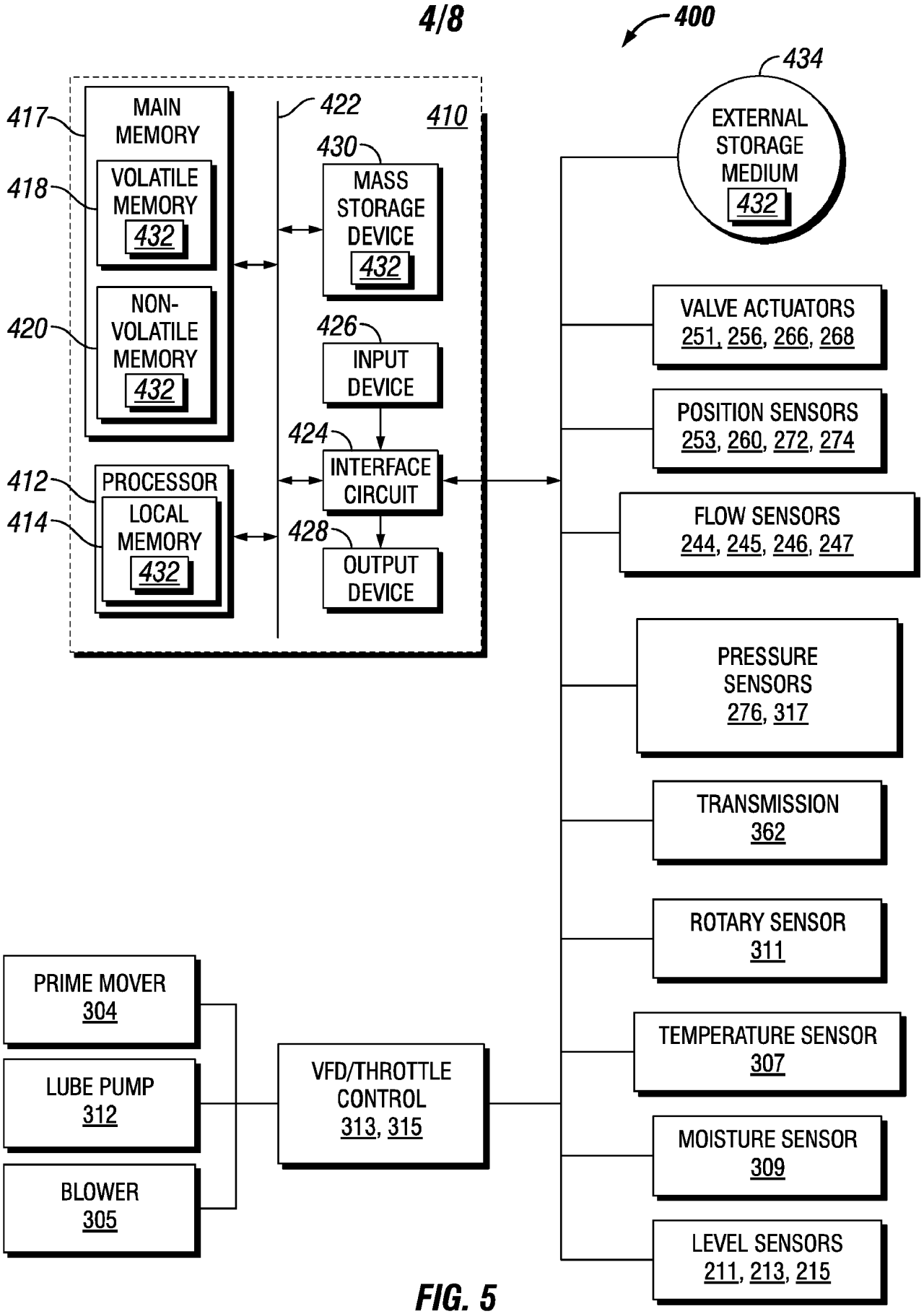

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434
EXTERNAL STORAGE MEDIUM 432
417
MAIN MEMORY
418
VOLATILE MEMORY 432
420
NON-VOLATILE MEMORY 432
412
PROCESSOR
414
LOCAL MEMORY 432
422
410
430
MASS STORAGE DEVICE 432
426
INPUT DEVICE
424
INTERFACE CIRCUIT
428
OUTPUT DEVICE
VALVE ACTUATORS 251, 256, 266, 268
POSITION SENSORS 253, 260, 272, 274
FLOW SENSORS 244, 245, 246, 247
PRESSURE SENSORS 276, 317
TRANSMISSION 362
ROTARY SENSOR 311
TEMPERATURE SENSOR 307
MOISTURE SENSOR 309
LEVEL SENSORS 211, 213, 215
PRIME MOVER 304
LUBE PUMP 312
BLOWER 305
VFD/THROTTLE CONTROL 313, 315

FIG. 5

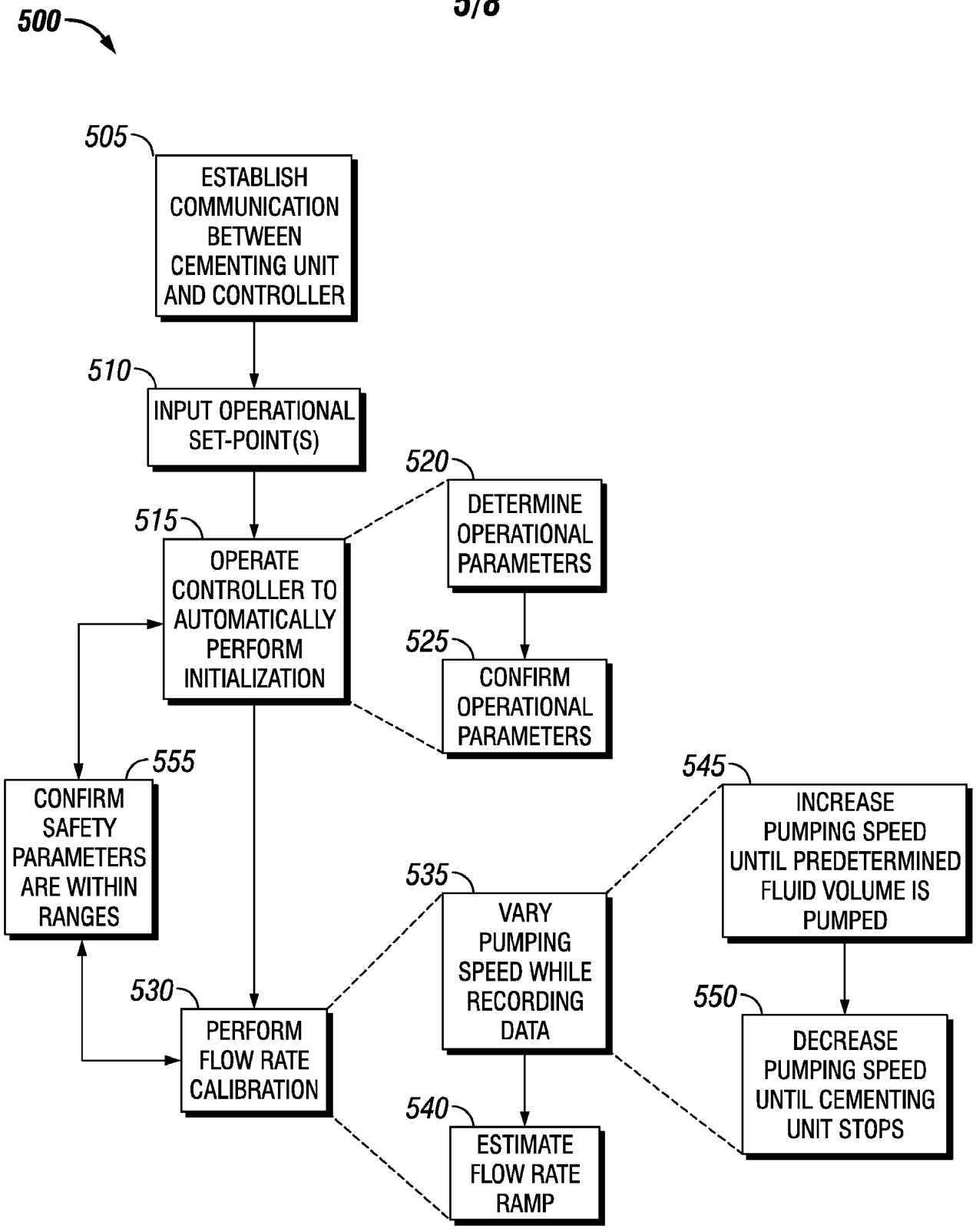

500
505
ESTABLISH COMMUNICATION BETWEEN CEMENTING UNIT AND CONTROLLER
510
INPUT OPERATIONAL SET-POINT(S)
515
OPERATE CONTROLLER TO AUTOMATICALLY PERFORM INITIALIZATION
520
DETERMINE OPERATIONAL PARAMETERS
525
CONFIRM OPERATIONAL PARAMETERS
530
PERFORM FLOW RATE CALIBRATION
535
VARY PUMPING SPEED WHILE RECORDING DATA
540
ESTIMATE FLOW RATE RAMP
545
INCREASE PUMPING SPEED UNTIL PREDETERMINED FLUID VOLUME IS PUMPED
550
DECREASE PUMPING SPEED UNTIL CEMENTING UNIT STOPS
555
CONFIRM SAFETY PARAMETERS ARE WITHIN RANGES

FIG. 6

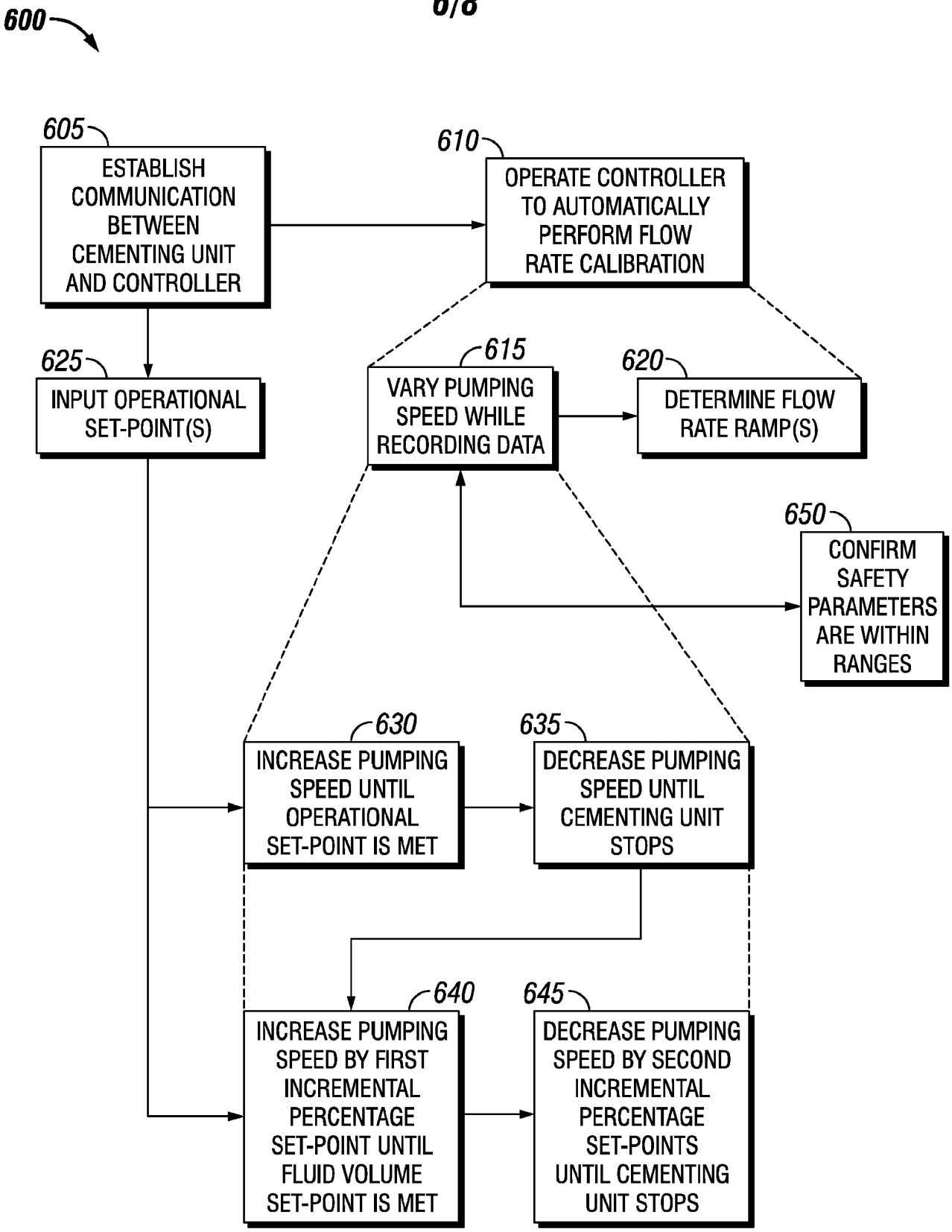

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ESTABLISH COMMUNICATION BETWEEN CEMENTING UNIT AND CONTROLLER
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OPERATE CONTROLLER TO AUTOMATICALLY PERFORM FLOW RATE CALIBRATION
625
INPUT OPERATIONAL SET-POINT(S)
615
VARY PUMPING SPEED WHILE RECORDING DATA
620
DETERMINE FLOW RATE RAMP(S)
650
CONFIRM SAFETY PARAMETERS ARE WITHIN RANGES
630
INCREASE PUMPING SPEED UNTIL OPERATIONAL SET-POINT IS MET
635
DECREASE PUMPING SPEED UNTIL CEMENTING UNIT STOPS
640
INCREASE PUMPING SPEED BY FIRST INCREMENTAL PERCENTAGE SET-POINT UNTIL FLUID VOLUME SET-POINT IS MET
645
DECREASE PUMPING SPEED BY SECOND INCREMENTAL PERCENTAGE SET-POINTS UNTIL CEMENTING UNIT STOPS

FIG. 7

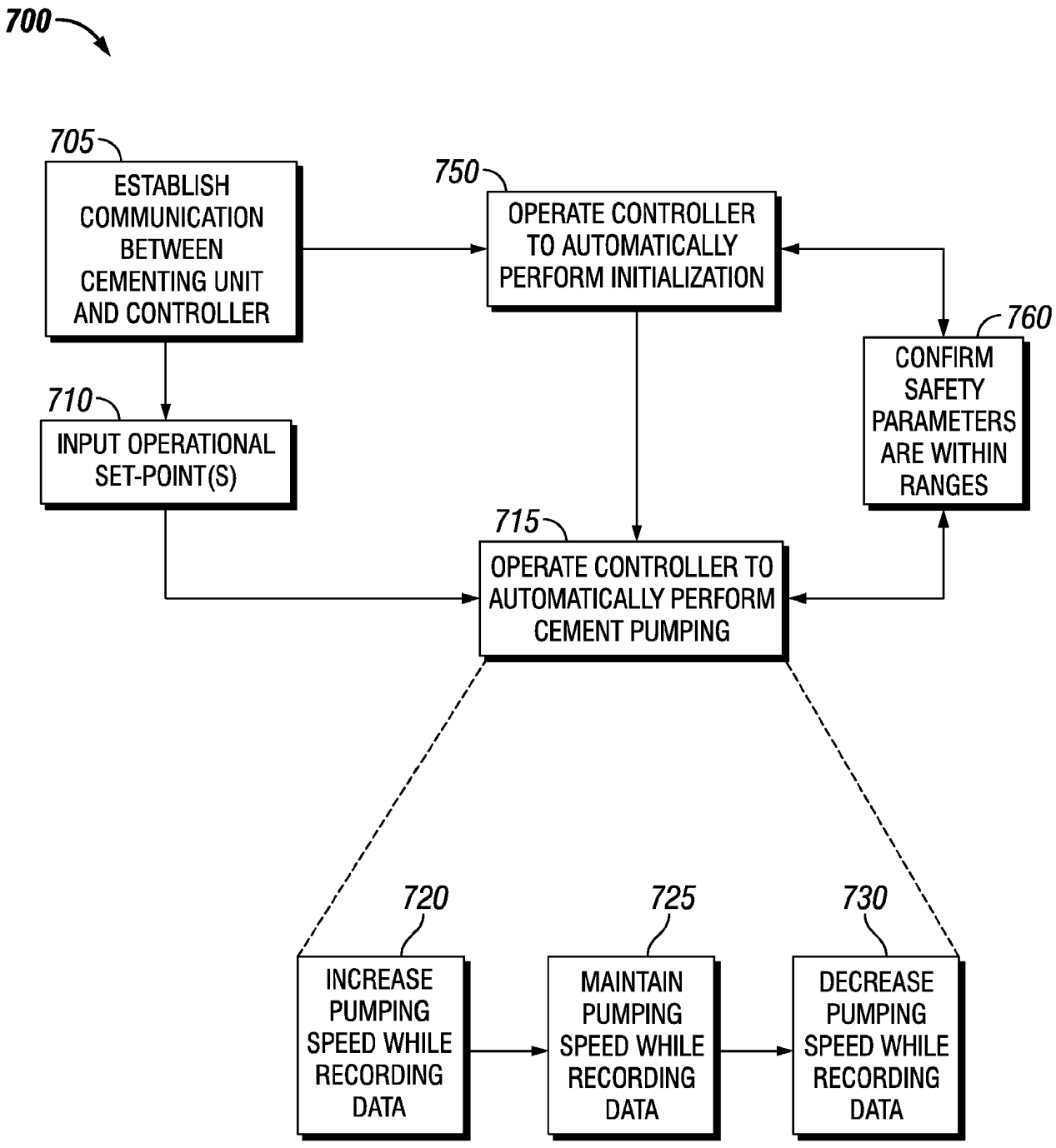

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ESTABLISH COMMUNICATION BETWEEN CEMENTING UNIT AND CONTROLLER
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OPERATE CONTROLLER TO AUTOMATICALLY PERFORM INITIALIZATION
760
CONFIRM SAFETY PARAMETERS ARE WITHIN RANGES
710
INPUT OPERATIONAL SET-POINT(S)
715
OPERATE CONTROLLER TO AUTOMATICALLY PERFORM CEMENT PUMPING
720
INCREASE PUMPING SPEED WHILE RECORDING DATA
725
MAINTAIN PUMPING SPEED WHILE RECORDING DATA
730
DECREASE PUMPING SPEED WHILE RECORDING DATA

FIG. 8

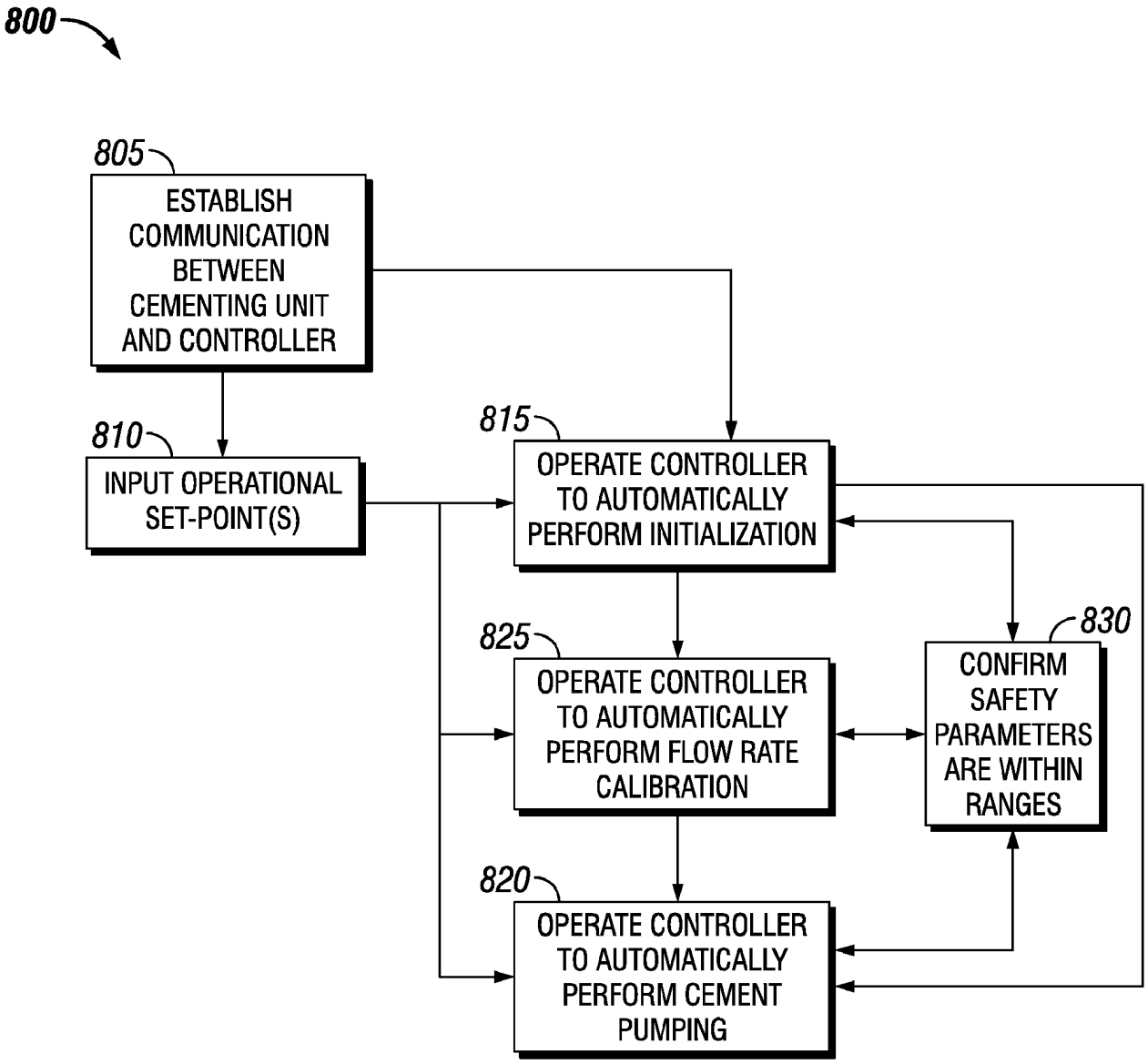

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ESTABLISH COMMUNICATION BETWEEN CEMENTING UNIT AND CONTROLLER
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INPUT OPERATIONAL SET-POINT(S)
815
OPERATE CONTROLLER TO AUTOMATICALLY PERFORM INITIALIZATION
825
OPERATE CONTROLLER TO AUTOMATICALLY PERFORM FLOW RATE CALIBRATION
830
CONFIRM SAFETY PARAMETERS ARE WITHIN RANGES
820
OPERATE CONTROLLER TO AUTOMATICALLY PERFORM CEMENT PUMPING

FIG. 9

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2016/023856

A. CLASSIFICATION OF SUBJECT MATTER

E21B 33/13(2006.01)i, E21B 33/138(2006.01)i, G05B 19/02(2006.01)i, G06F 19/00(2011.01)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)
E21B 33/13; F04B 49/00; F04D 29/00; F04B 47/02; E21B 33/138; G05B 19/02; G06F 19/00

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: pump, automatically, cementing, flow rate, calibration, speed, ramp, volume, pressure, vary

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US 2004-0120804 A1 (SABINI et al.) 24 June 2004 See paragraphs [0002], [0022]-[0030], [0040]-[0046], [0052], [0060]; and figures 1, 4, 8.	1-28
Y	WO 97-08459 A1 (BAKER HUGHES INCORPORATED et al.) 06 March 1997 See page 36, line 26 - page 37, line 8; page 46, lines 3-15; page 51, lines 5-16; page 63, line 30 - page 64, line 1; and figures 2B, 2D.	1-28
A	US 3705626 A (GLENN, JR. et al.) 12 December 1972 See column 5, line 18 - column 6, line 51; and figures 1-2.	1-28
A	US 2012-0301320 A1 (SEITTER, LARRY E.) 29 November 2012 See paragraphs [0041]-[0070]; and figures 4-7.	1-28
A	US 5006044 A (WALKER, SR. et al.) 09 April 1991 See column 21, line 48 - column 24, line 10; and figure 2.	1-28

☐ 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
"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	Date of mailing of the international search report
26 June 2016 (26.06.2016)	**27 June 2016 (27.06.2016)**

Name and mailing address of the ISA/KR
International Application Division
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

Information on patent family members

International application No.

PCT/US2016/023856

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
US 2004-0120804 A1	24/06/2004	AU 2003-297991 A1	22/07/2004
		AU 2003-297991 A8	22/07/2004
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		DE 10393946 T5	24/05/2007
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WO 97-08459 A1	06/03/1997	AU 2001-57514 A1	20/11/2001
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		CA 2230691 C	30/03/2004
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		NO 324610 B1	26/11/2007
		NO 980882 A	27/04/1998
		US 2001-0032721 A1	25/10/2001
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		US 7248178 B2	24/07/2007
		WO 01-86831 A1	15/11/2001
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US 2012-0301320 A1	29/11/2012	EP 2715059 A2	09/04/2014
		EP 2715059 A4	04/11/2015
		US 9121270 B2	01/09/2015
		WO 2012-162528 A2	29/11/2012
		WO 2012-162528 A3	21/03/2013
US 5006044 A	09/04/1991	US 5063775 A	12/11/1991
		US 5222867 A	29/06/1993

Electronic Patent Application Fee Transmittal

Application Number:	16597014
Filing Date:	09-Oct-2019
Title of Invention:	MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT
First Named Inventor/Applicant Name:	Jared Oehring
Filer:	Taylor P. Evans/Stephanie McDonough
Attorney Docket Number:	047158.100048

Filed as Large Entity

Filing Fees for Utility under 35 USC 111(a)

Description	Fee Code	Quantity	Amount	Sub-Total in USD($)
Basic Filing:				
Pages:				
Claims:				
Miscellaneous-Filing:				
Petition:				
Patent-Appeals-and-Interference:				
Post-Allowance-and-Post-Issuance:				
Extension-of-Time:				

Description	Fee Code	Quantity	Amount	Sub-Total in USD($)
Miscellaneous:				
SUBMISSION- INFORMATION DISCLOSURE STMT	1806	1	240	240
		Total in USD ($)		**240**

Electronic Acknowledgement Receipt

EFS ID:	39742520
Application Number:	16597014
International Application Number:	
Confirmation Number:	4687
Title of Invention:	MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT
First Named Inventor/Applicant Name:	Jared Oehring
Customer Number:	132858
Filer:	Taylor P. Evans/Stephanie McDonough
Filer Authorized By:	Taylor P. Evans
Attorney Docket Number:	047158.100048
Receipt Date:	17-JUN-2020
Filing Date:	09-OCT-2019
Time Stamp:	11:08:21
Application Type:	Utility under 35 USC 111(a)

Payment information:

Submitted with Payment	yes
Payment Type	DA
Payment was successfully received in RAM	$240
RAM confirmation Number	E20206GB08566554
Deposit Account	501349
Authorized User	Stephanie McDonough

The Director of the USPTO is hereby authorized to charge indicated fees and credit any overpayment as follows:

37 CFR 1.16 (National application filing, search, and examination fees)

37 CFR 1.17 (Patent application and reexamination processing fees)

37 CFR 1.19 (Document supply fees)

37 CFR 1.20 (Post Issuance fees)

37 CFR 1.21 (Miscellaneous fees and charges)

File Listing:

Document Number	Document Description	File Name	File Size(Bytes)/ Message Digest	Multi Part /.zip	Pages (if appl.)
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Information:					
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24	Foreign Reference	WO2016144939A1.pdf	2806113 872bb70d656a1509be358ed84d26d96df024df95	no	51
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25	Foreign Reference	WO2016160458A1.pdf	2943101 c19c0fff68082843578b747bb7ab73e084460695	no	57
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26	Non Patent Literature	NPL-1.pdf	265555 591acdd0884e7418b119f5770a99b349ff7fdd1b	no	2
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Information:					
			Total Files Size (in bytes):	77907380	

This Acknowledgement Receipt evidences receipt on the noted date by the USPTO of the indicated documents, characterized by the applicant, and including page counts, where applicable. It serves as evidence of receipt similar to a Post Card, as described in MPEP 503.

New Applications Under 35 U.S.C. 111

If a new application is being filed and the application includes the necessary components for a filing date (see 37 CFR 1.53(b)-(d) and MPEP 506), a Filing Receipt (37 CFR 1.54) will be issued in due course and the date shown on this Acknowledgement Receipt will establish the filing date of the application.

National Stage of an International Application under 35 U.S.C. 371

If a timely submission to enter the national stage of an international application is compliant with the conditions of 35 U.S.C. 371 and other applicable requirements a Form PCT/DO/EO/903 indicating acceptance of the application as a national stage submission under 35 U.S.C. 371 will be issued in addition to the Filing Receipt, in due course.

New International Application Filed with the USPTO as a Receiving Office

If a new international application is being filed and the international application includes the necessary components for an international filing date (see PCT Article 11 and MPEP 1810), a Notification of the International Application Number and of the International Filing Date (Form PCT/RO/105) will be issued in due course, subject to prescriptions concerning national security, and the date shown on this Acknowledgement Receipt will establish the international filing date of the application.

IN THE UNITED STATES PATENT AND TRADEMARK OFFICE

In re Application of:	§	
Oehring	§	Attorney Docket No.: 047158.100048
	§	
Serial No.: 16/597,014	§	Confirmation No. : 4687
	§	
Filed: October 9, 2019	§	Art Unit: 3746
	§	
MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT	§	Examiner: Bobish, Christopher S.

Mail Stop Amendment
Commissioner for Patents
P.O. Box 1450
Alexandria, VA 22313-1450

AMENDMENT

Dear Sir/Madam:

In response to the Non-Final Office Action mailed January 10, 2020, Applicant hereby requests reconsideration of the above-referenced Application for patent, and reconsideration of the rejections in view of the amendments and the following arguments. Applicant hereby authorizes the Commissioner to charge any fees necessary for continued prosecution of this Application to **Hogan Lovells US LLP's Deposit Account Number 501349**.

Electronic Acknowledgement Receipt

EFS ID:	39109824
Application Number:	16597014
International Application Number:	
Confirmation Number:	4687
Title of Invention:	MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT
First Named Inventor/Applicant Name:	Jared Oehring
Customer Number:	132858
Filer:	Joe Grdinovac/Stephanie McDonough
Filer Authorized By:	Joe Grdinovac
Attorney Docket Number:	047158.100048
Receipt Date:	09-APR-2020
Filing Date:	09-OCT-2019
Time Stamp:	12:20:41
Application Type:	Utility under 35 USC 111(a)

Payment information:

Submitted with Payment	no

File Listing:

Document Number	Document Description	File Name	File Size(Bytes)/ Message Digest	Multi Part /.zip	Pages (if appl.)
1		100048_Response.pdf	90846 e1a163a2ba9448ea1ebdb4becfff20cfabc31e78	yes	14

	Multipart Description/PDF files in .zip description		
	Document Description	**Start**	**End**
	Applicant Arguments/Remarks Made in an Amendment	7	14
	Claims	2	6
	Amendment/Req. Reconsideration-After Non-Final Reject	1	1
Warnings:			
Information:			
	Total Files Size (in bytes):	90846	

This Acknowledgement Receipt evidences receipt on the noted date by the USPTO of the indicated documents, characterized by the applicant, and including page counts, where applicable. It serves as evidence of receipt similar to a Post Card, as described in MPEP 503.

New Applications Under 35 U.S.C. 111

If a new application is being filed and the application includes the necessary components for a filing date (see 37 CFR 1.53(b)-(d) and MPEP 506), a Filing Receipt (37 CFR 1.54) will be issued in due course and the date shown on this Acknowledgement Receipt will establish the filing date of the application.

National Stage of an International Application under 35 U.S.C. 371

If a timely submission to enter the national stage of an international application is compliant with the conditions of 35 U.S.C. 371 and other applicable requirements a Form PCT/DO/EO/903 indicating acceptance of the application as a national stage submission under 35 U.S.C. 371 will be issued in addition to the Filing Receipt, in due course.

New International Application Filed with the USPTO as a Receiving Office

If a new international application is being filed and the international application includes the necessary components for an international filing date (see PCT Article 11 and MPEP 1810), a Notification of the International Application Number and of the International Filing Date (Form PCT/RO/105) will be issued in due course, subject to prescriptions concerning national security, and the date shown on this Acknowledgement Receipt will establish the international filing date of the application.

REMARKS

This amendment is in response to the Non-Final Office Action mailed January 10, 2020. Claims 1-20 are pending with claims 1, 9, and 17 being independent. Claims 1-20 stand rejected. Specifically, claims 4 and 11 are objected to for alleged informalities. Claims 7, 9, 14, 18, and 19 are rejected under 35 U.S.C. § 112(b) as allegedly indefinite. Claims 1, 2, 5, 6, 9, 12, 13, 16, and 17 are rejected under 35 U.S.C. § 103 as allegedly unpatentable over Morris et al. (U.S. Patent Publication No. 2019/0203572; hereinafter "Morris"). Claims 3, 4, 10, 11, and 18-20 stand rejected under 35 U.S.C. § 103 as allegedly unpatentable over Morris and Mori et al. (U.S. Patent No. 7,835,140; hereinafter "Mori"). Claims 8 and 15 stand rejected under 35 U.S.C. § 103 as allegedly unpatentable over Morris and Symchuk (U.S. Patent No. 9,932,799; hereinafter "Symchuk"). Claims 7 and 14 stand rejected under 35 U.S.C. § 103 as allegedly unpatentable over Morris and Oehring et al. (U.S. Patent Publication No. 2016/0105022; hereinafter "Oehring"). Applicant respectfully disagrees and traverses these rejections.

By the present response, claims 4, 7, 9, 11, 14, 18, and 19 are amended, without prejudice. No new matter is added. Upon entry of the amendments, Claims 1-20 will remain pending. Applicant respectfully requests reconsideration and allowance of the pending claims.

I. Examiner Interview

A telephone interview was conducted with Examiner Bobish on April 8, 2020. The undersigned attorney represented Applicant during the interview. No agreement as to patentability was reached during the interview, but claim 1 and the interpretation of Morris was discussed. Applicant thanks the Examiner for conducting the interview.

II. Claims 4 and 11 Comply with Formalities

The Office Action objects to claims 4 and 11 for alleged informalities. Applicant has amended claims 4 and 11 to address inadvertent typographical errors. Accordingly, Applicant respectfully requests withdrawal of the objections to claims 4 and 11.

III. Claims 7, 9, 14, 18, and 19 are Definite

The Office Action rejects claims 7, 9, 14, 18, and 19 as allegedly indefinite. While Applicant does not necessarily agree with the rejections, in order to advance prosecution, Applicant has amended claims 7, 9, 14, 18, and 19. Accordingly, Applicant respectfully requests withdrawal of the rejections.

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IV. Claims 1, 2, 5, 6, 9, 12, 13, 16, and 17 are Patentable over Morris

The Office Action rejects claims 1, 2, 5, 6, 9, 12, 13, 16, and 17 under 35 U.S.C. § 103 as allegedly unpatentable over Morris. Applicant respectfully disagrees and traverses this rejection.

As an initial matter, for claimed subject matter to be obvious, either the prior art references must expressly teach each claim limitation or else the record must disclose a reason for a person of ordinary skill in the art to modify the prior art teachings to obtain the claimed invention. *Beckson Marine, Inc. v. NFM, Inc.*, 292 F.3d 718, 727 (Fed. Cir. 2002). The rejection must make "a searching comparison of the claimed invention—including all its limitations—with the teaching of the prior art." *In re Wada and Murphy*, Appeal 2007-3733, citing *In re Ochiai*, 71 F.3d 1565, 1572 (Fed. Cir. 1995) and *CMFT v. Yieldup Intern. Corp.*, 349 F.3d 1333, 1342 (Fed. Cir. 2003) (emphasis added). Indeed, the references used to make the rejection must, at the very least, suggest all of the claim elements. Further, the Office must provide evidence which, as a whole, shows that the legal determination sought to be proved (i.e., the reference teachings establish a prima facie case of obviousness) is more probable than not. M.P.E.P. § 2142. Accordingly, "the key to supporting any rejection under … 103 is the clear articulation of the reason(s) why the claimed invention would have been obvious." *Id. See also KSR Int'l Co. v. Teleflex, Inc.*, 550 U.S. 398, 82 U.S.P.Q.2d 1385, 1395-97 (2007).

Additionally, Section 2142 of the M.P.E.P. states that, in an obviousness analysis, "impermissible hindsight must be avoided and the legal conclusion must be reached on the basis of the facts *gleaned from the prior art*" (emphasis added). *See also* M.P.E.P. § 2145(X)(A) (stating "[a]ny judgment on obviousness is in a sense necessarily a reconstruction based on hindsight reasoning, but so long as it takes into account only knowledge which was within the level of ordinary skill in the art at the time the claimed invention was made and *does not include knowledge gleaned only from applicant's disclosure*, such a reconstruction is proper" (quoting *In re McLaughlin*, 443 F.2d 1392, 1395 (C.C.P.A. 1971)) (emphasis added)). The mere fact that references can be combined or modified does not render the resultant combination obvious unless the prior art also suggests the desirability of the combination. *In re Mills*, 916 F.2d 680, 683 (Fed. Cir 1990); M.P.E.P. § 2143.01. Moreover, the Federal Circuit has instructed that "[o]ne cannot use hindsight reconstruction to pick and choose among isolated disclosures in the prior art to deprecate the claimed invention." *In re Fine*, 837 F.2d 1071, 1075 (Fed. Cir. 1988).

Finally, it is improper to combine references where the references teach away from their combination. *In re Grasselli*, 713 F.2d 731, 743 (Fed. Cir. 1983).

A. Independent Claim 1

Applicant's independent claim 1 recites:

> A hydraulic fracturing system for fracturing a subterranean formation, comprising:
>
> a support structure having a first area, a second area, a third area, and a fourth area arranged adjacent one another;
>
> an electric powered, multi-plunger pump with up to 15 plungers, arranged in the first area, the electric powered pump coupled to a well associated with the subterranean formation and powered by at least one electric motor, also arranged in the first area, the electric powered pump configured to pump fluid into a wellbore associated with the well at a high pressure so that the fluid passes from the wellbore into the subterranean formation and fractures the subterranean formation;
>
> a variable frequency drive (VFD), arranged in the second area proximate the first area, connected to the at least one electric motor to control the speed of the at least one electric motor;
>
> a transformer, arranged in the third area proximate the second area, the transformer positioned within an enclosure, the transformer distributing power to the electric pump, the power being received from at least one generator at a voltage higher than an operating voltage of the electric pump; and
>
> a cooling system, arranged in the fourth area proximate the third area, the cooling system providing a cooling fluid to the VFD via one or more headers.

Applicant respectfully asserts that the Office Action at least fails to identify each feature of claim 1 in the prior art, and moreover, fails to provide sufficient rationale to support a rejection under 35 U.S.C. § 103. Accordingly, Applicant respectfully requests withdrawal of the rejection of claim 1.

1. The cited reference does not teach the claimed "variable frequency drive" of claim 1.

The Office Action contends that paragraphs 77 and 79 support the contention that the variable frequency drive (VFD) is "arranged in the second area proximate the first area," as recited in claim 1. *See* Office Action, 4. Applicant respectfully disagrees. By way of example, cited paragraph 77 makes a passing reference to VFDs regarding various transports arranged at the well site. There is no indication that the pumps and VFDs share this transport. Moreover, FIG. 1 illustrates that they do not. For example, paragraph 46 indicates that "drive

power transports 104 comprise one or more variable frequency drives (VFDs)…" *See* Morris, ¶ [0046]. These drive power transports 104 are clearly illustrated as being separate and distinct from the "fracturing pump transports 108." *See id.* at ¶ [0046] and FIG. 1. Additionally, the rejections set forth in the Office Action make particular reference to FIGS. 7A and 7B, which Morris explicitly states illustrate details of the pump transports 108, which are shown separate from the drive power transports 104. *See id.* at ¶ [0047]. Accordingly, the interpretation offered by the Examiner is directly contradicted by the disclosure of the cited reference. Accordingly, Applicant respectfully requests withdrawal of the rejection of claim 1.

The citation to paragraph 79 offers no improvement. Once again, VFDs are only mentioned in passing, with no indication that the VFD is positioned on the same support structure as the pumps. As previously indicated, a different configuration of components is specifically disclosed in Morris. Because there is no indication that the VFD and pump are arranged on the same support structure, and moreover Morris explicitly illustrates they are not, Applicant respectfully submits that the obviousness rejection is in error, conclusory, and based on hindsight, using Applicant's disclosure as a roadmap. Accordingly, Applicant respectfully requests withdrawal of the rejection of claim 1.

2. The cited reference does not teach the claimed "cooling system" of claim 1.

The Office Action concedes "Morris does not explicitly teach a cooling system for the VFD on the pump trailer 710…." Office Action at 4. Applicant agrees. However, the Office Action contends, with reference to paragraph 46, that this arrangement would be obvious. *See id.* Applicant respectfully disagrees.

As an initial matter, Applicant has already explained why Morris does not disclosure the arrangement of the VFD on the same support structure as the pumps, and moreover, how Morris teaches a contradictory arrangement including the VFDs on separate support structures. *See* Morris, FIG. 1. Cited paragraph 46 is further in reference to the drive power transports 104, which are separate from the pump transports 108. Accordingly, Applicant asserts that the combination is improper and respectfully requests withdrawal of the rejection of claim 1.

B. Independent Claim 9

Applicant's independent claim 9 recites:

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A hydraulic fracturing system for fracturing a subterranean formation, comprising:

at least one generator;

at least one switchgear receiving electrical power from the generator;

an electric powered pump, arranged on a support structure, the electric powered pump coupled to a well associated with the subterranean formation and powered by at least one electric motor, the electric powered pump configured to pump fluid into a wellbore associated with the well at a high pressure so that the fluid passes from the wellbore into the subterranean formation and fractures the subterranean formation;

a variable frequency drive (VFD), arranged on the support structure proximate the electric powered pump, connected to the at least one electric motor to control the speed of the at least one electric motor;

a transformer, arranged on the support structure proximate the VFD, the transformer distributing power to the electric powered pump, the power being received from the least one generator at a voltage higher than an operating voltage of the electric powered pump; and

a cooling system, arranged on the support structure proximate the transformer, the cooling system providing a cooling fluid to the VFD.

Applicant respectfully asserts that the Office Action at least fails to identify each feature of claim 8 in the prior art, and moreover, fails to provide sufficient rationale to support a rejection under 35 U.S.C. § 103, for at least the reasons stated above with respect to claim 1. Independent claim 9 recites certain features that are similar to claim 1, including at least, "a variable frequency drive (VFD), arranged on the support structure proximate the electric powered pump, connected to the at least one electric motor to control the speed of the at least one electric motor" and "a cooling system, arranged on the support structure proximate the transformer, the cooling system providing a cooling fluid to the VFD." Accordingly, Applicant respectfully requests withdrawal of the rejection of claim 9.

C. Independent Claim 17

Applicant's independent claim 17 recites:

A hydraulic fracturing system for fracturing a subterranean formation, comprising:

a plurality of electric powered pumps coupled to a well associated with the subterranean formation and powered by at least one electric motor, the electric powered pump configured to pump fluid into a wellbore associated with the well at a high pressure so that the fluid passes from the wellbore into the subterranean formation and fractures the subterranean formation;

a variable frequency drive (VFD) connected to the at least one electric motor to control the speed of the at least one electric motor;

a transformer for conditioning power to the electric powered pump, the power being received from at least one generator at a voltage higher than an operating voltage of the electric pump; and

a switchgear, receiving power from at least one generator, configured to distribute power to a plurality of pieces of wellsite equipment, the switchgear having a common load sharing bus.

Applicant respectfully asserts that the Office Action at least fails to identify each feature of claim 17 in the prior art, and moreover, fails to provide sufficient rationale to support a rejection under 35 U.S.C. § 103. For example, the cited reference at least fails to teach or suggest "a switchgear, receiving power from at least one generator, configured to distribute power to a plurality of pieces of wellsite equipment, the switchgear having a common load sharing bus." Accordingly, Applicant respectfully requests withdrawal of the rejection.

The Office Action contends paragraph 44 taches the claimed switchgear and common bus. *See* Office Action at 4. The cited paragraph is reproduced below:

> The mobile source of electricity 102 may supply electric power to fracturing equipment within the mobile fracturing system 103 that may include, but is not limited to, at least one switch gear transport 112, a plurality of drive power transports 104, at least one auxiliary power transport 106, at least one blender transport 110, at least one data van 114 and a plurality of fracturing pump transports 108 that deliver fracturing fluid through wellhead 101 to subsurface geological formations. The switch gear transport 112 may receive the electricity generated from the mobile source of electric power 102 via one or more electrical connections. In one embodiment, the switch gear transport 112 may use 13.8 kilovolts (KV) electrical connections to receive power from the mobile source of electric power 102. The switch gear transport 112 may comprise a plurality of electrical disconnect switches, fuses, transformers, and/or circuit protectors to protect the fracturing equipment. The switch gear transport 112 may transfer the electricity received from the mobile source of electricity 102 to the drive power transports 104 and auxiliary power transports 106.

Morris, ¶ [0044]. As shown, there is no reference to a "common bus" and the Office Action provides no rationale why one skilled in the art would assume "a plurality of electrical disconnect switches, fuses, transformers, and/or circuit protectors" would correspond to the

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claimed "common bus." Instead, the Office Action merely provides a conclusory citation to the paragraph with no further description or rationale to support the rejection. This is improper, and as such, Applicant respectfully requests withdrawal of the rejection of claim 17.

D. Dependent Claims 2, 5, 6, 12, 13, and 16

Claims 2, 5, 6, 12, 13, and 16 depend from at least one of independent claims 1 and 9. Accordingly, Applicant respectfully asserts these claims are allowable at least due to their dependence from an allowable base claim. Accordingly, Applicant respectfully requests withdrawal of the rejection of claims 2, 5, 6, 12, 13, and 16.

V. Claims 3, 4, 10, 11, and 18-20 are Patentable over Morris and Mori

The Office Action rejects claims 3, 4, 10, 11, and 18-20 as allegedly unpatentable over Morris and Mori. Applicant respectfully disagrees and traverses this rejection.

Claims 3, 4, 10, 11, and 18-20 depend from at least one of independent claims 1, 9, and 17. Accordingly, Applicant respectfully asserts the claims are allowable at least due to their dependence from an allowable base claim. Accordingly, Applicant respectfully requests withdrawal of the rejection of claims 3, 4, 10, 11, and 18-20.

VI. Claims 8 and 15 are Patentable over Morris and Symchuk

The Office Action rejects claims 8 and 15 as allegedly unpatentable over Morris and Symchuk. Applicant respectfully disagrees and traverses this rejection.

Claims 8 and 15 depend from at least one of independent claims 1 and 9. Accordingly, Applicant respectfully asserts the claims are allowable at least due to their dependence from an allowable base claim. Accordingly, Applicant respectfully requests withdrawal of the rejection of claims 8 and 15.

VII. Claims 7 and 14 are Patentable over Morris and Oehring

The Office Action rejects claims 7 and 14 as allegedly unpatentable over Morris and Oehring. Applicant respectfully disagrees and traverses this rejection.

Claims 7 and 14 depend from at least one of independent claims 1 and 9. Accordingly, Applicant respectfully asserts the claims are allowable at least due to their dependence from an allowable base claim. Accordingly, Applicant respectfully requests withdrawal of the rejection of claims 7 and 14.

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VIII. Conclusion

The foregoing response is full, complete, and timely filed. Amendments to the claims are made without prejudice, including under the doctrine of equivalents. In addition, the comments made herein are without prejudice. Applicant respectfully requests reconsideration of the instant application in light of the foregoing response and amendments. Should the Examiner have any questions, comments or suggestions in furtherance of the prosecution of the application, the Examiner is invited to contact the Applicant's representative by telephone or fax.

Respectfully submitted,

Date: April 9, 2020

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AMENDMENTS TO THE CLAIMS

The following listing of claims replaces all prior versions and listing of claims in the application.

Listing of claims:

1. (Original) A hydraulic fracturing system for fracturing a subterranean formation, comprising:

a support structure having a first area, a second area, a third area, and a fourth area arranged adjacent one another;

an electric powered, multi-plunger pump with up to 15 plungers, arranged in the first area, the electric powered pump coupled to a well associated with the subterranean formation and powered by at least one electric motor, also arranged in the first area, the electric powered pump configured to pump fluid into a wellbore associated with the well at a high pressure so that the fluid passes from the wellbore into the subterranean formation and fractures the subterranean formation;

a variable frequency drive (VFD), arranged in the second area proximate the first area, connected to the at least one electric motor to control the speed of the at least one electric motor;

a transformer, arranged in the third area proximate the second area, the transformer positioned within an enclosure, the transformer distributing power to the electric pump, the power being received from at least one generator at a voltage higher than an operating voltage of the electric pump; and

a cooling system, arranged in the fourth area proximate the third area, the cooling system providing a cooling fluid to the VFD via one or more headers.

2. (Original) The system of claim 1, further comprising:

a control system arranged in the fourth area, the control system including one or more operating parameters of the electric pump, VFD, transformer, or cooling system.

3. (Original) The system of claim 1, further comprising:

a switchgear subassembly, the switchgear subassembly having integrated core units configured to operate in a connected position, an open position, or a grounded position.

4. (Currently Amended) The system of claim 3, wherein the switchgear subassembly comprises:

a busbar shielded, at least partially, by solid insulation;

an isolating ground ~~round~~ switch, enclosed within a tank arranged proximate the busbar; and

cable connections for coupling to the switchgear.

5. (Original) The system of claim 1, wherein the fourth section is arranged at a higher elevation than the first section, the fourth section associated with a gooseneck portion of a trailer.

6. (Original) The system of claim 1, wherein the support structure is at least one of a trailer, a skid, a pad, a truck bed, or a combination thereof.

7. (Currently Amended) The system of claim 1, further comprising:

cable trays positioned below a walking surface of the fourth section, the cable trays ~~channels~~ being covered by a hinged cover that pivots to provide access to the cable trays ~~channels~~.

8. (Original) The system of claim 1, wherein the cooling system comprises a radiator that utilizes a water/glycol mixture.

9. (Currently Amended) A hydraulic fracturing system for fracturing a subterranean formation, comprising:

at least one generator;

at least one switchgear receiving electrical power from the generator;

an electric powered pump, arranged on a support structure, the electric powered pump coupled to a well associated with the subterranean formation and powered by at least one electric

motor, the electric powered pump configured to pump fluid into a wellbore associated with the well at a high pressure so that the fluid passes from the wellbore into the subterranean formation and fractures the subterranean formation;

a variable frequency drive (VFD), arranged on the support structure proximate the electric powered pump, connected to the at least one electric motor to control the speed of the at least one electric motor;

a transformer, arranged on the support structure proximate the VFD, the transformer distributing power to the electric powered pump, the power being received from the least one generator at a voltage higher than an operating voltage of the electric powered pump; and

a cooling system, arranged on the support structure proximate the transformer, the cooling system providing a cooling fluid to ~~at least~~ the VFD.

10. (Original) The system of claim 9, wherein the at least one switchgear comprises integrated core units configured to operate in a connected position, an open position, or a grounded position.

11. (Currently Amended) The system of claim 10, wherein the switchgear subassembly comprises:

a busbar shielded, at least partially, by solid insulation;

an isolating ground ~~round~~ switch, enclosed within a tank arranged proximate the busbar; and

cable connections for coupling to the switchgear.

12. (Original) The system of claim 9, further comprising:

a transformer service platform that provides access to the transformer, the transformer service platform positioned at a higher elevation than at least a portion of a base of the electric powered pump.

13. (Original) The system of claim 9, wherein the support structure is at least one of a trailer, a skid, a pad, a truck bed, or a combination thereof.

14. (Currently Amended) The system of claim 9, further comprising:

cable trays positioned below a walking surface of the support structure, the cable trays ~~channels~~ being covered by a hinged cover that pivots to provide access to the cable trays ~~channels~~.

15. (Original) The system of claim 9, wherein the cooling system comprises a radiator that utilizes a water/glycol mixture.

16. (Original) The system of claim 9, further comprising:

a human machine interface, positioned proximate the VFD; and

a platform cover at least partially covering the humane machine interface and VFD.

17. (Original) A hydraulic fracturing system for fracturing a subterranean formation, comprising:

a plurality of electric powered pumps coupled to a well associated with the subterranean formation and powered by at least one electric motor, the electric powered pump configured to pump fluid into a wellbore associated with the well at a high pressure so that the fluid passes from the wellbore into the subterranean formation and fractures the subterranean formation;

a variable frequency drive (VFD) connected to the at least one electric motor to control the speed of the at least one electric motor;

a transformer for conditioning power to the electric powered pump, the power being received from at least one generator at a voltage higher than an operating voltage of the electric pump; and

a switchgear, receiving power from at least one generator, configured to distribute power to a plurality of pieces of wellsite equipment, the switchgear having a common load sharing bus.

18. (Currently Amended) The system of claim 17, wherein the common load sharing bus is configured to synchronize three-phase power of a similar voltage and frequency from different sources, the switchgear evenly distributing an electrical load between the plurality of electric pumps and the at least one generator ~~turbine generators~~.

19. (Currently Amended) The system of claim 17, wherein the common load sharing bus is configured to isolate one or more of the plurality of electric powered pumps, the at least one ~~turbine~~ generator, and the switchgear.

20. (Original) The system of claim 17, wherein the plurality of electric pumps, VFD, and transformer are mounted on a common support structure and a single cable couples the switchgear to the common support structure.

PTO/SB/06 (09-11)
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PATENT APPLICATION FEE DETERMINATION RECORD Substitute for Form PTO-875	Application or Docket Number 16/597,014	Filing Date 10/09/2019	☐ To be Mailed

ENTITY: ☑ LARGE ☐ SMALL ☐ MICRO

APPLICATION AS FILED - PART I

FOR	(Column 1) NUMBER FILED	(Column 2) NUMBER EXTRA		RATE ($)	FEE ($)
☐ BASIC FEE (37 CFR 1.16(a), (b), or (c))	N/A	N/A		N/A	
☐ SEARCH FEE (37 CFR 1.16(k), (i), or (m))	N/A	N/A		N/A	
☐ EXAMINATION FEE (37 CFR 1.16(o), (p), or (q))	N/A	N/A		N/A	
TOTAL CLAIMS (37 CFR 1.16(i))	minus 20 =	*		x $100 =	
INDEPENDENT CLAIMS (37 CFR 1.16(h))	minus 3 =	*		x $460 =	
☐ APPLICATION SIZE FEE (37 CFR 1.16(s))	If the specification and drawings exceed 100 sheets of paper, the application size fee due is $310 ($155 for small entity) for each additional 50 sheets or fraction thereof. See 35 U.S.C. 41(a)(1)(G) and 37 CFR 1.16(s).				
☐ MULTIPLE DEPENDENT CLAIM PRESENT (37 CFR 1.16(j))					
* If the difference in column 1 is less than zero, enter "0" in column 2.				TOTAL	

APPLICATION AS AMENDED - PART II

		(Column 1)		(Column 2)	(Column 3)			
AMENDMENT	04/09/2020	CLAIMS REMAINING AFTER AMENDMENT		HIGHEST NUMBER PREVIOUSLY PAID FOR	PRESENT EXTRA		RATE ($)	ADDITIONAL FEE ($)
	Total (37 CFR 1.16(i))	* 20	Minus	** 20	= 0		x $100 =	0
	Independent (37 CFR 1.16(h))	* 3	Minus	*** 3	= 0		x $460 =	0
	☐ Application Size Fee (37 CFR 1.16(s))							
	☐ FIRST PRESENTATION OF MULTIPLE DEPENDENT CLAIM (37 CFR 1.16(j))							
							TOTAL ADD'L FEE	0

		(Column 1)		(Column 2)	(Column 3)			
AMENDMENT		CLAIMS REMAINING AFTER AMENDMENT		HIGHEST NUMBER PREVIOUSLY PAID FOR	PRESENT EXTRA		RATE ($)	ADDITIONAL FEE ($)
	Total (37 CFR 1.16(i))	*	Minus	**	=		x $0 =	
	Independent (37 CFR 1.16(h))	*	Minus	***	=		x $0 =	
	☐ Application Size Fee (37 CFR 1.16(s))							
	☐ FIRST PRESENTATION OF MULTIPLE DEPENDENT CLAIM (37 CFR 1.16(j))							
							TOTAL ADD'L FEE	

* If the entry in column 1 is less than the entry in column 2, write "0" in column 3.	LIE
** If the "Highest Number Previously Paid For" IN THIS SPACE is less than 20, enter "20".	/POLIN ANG/
*** If the "Highest Number Previously Paid For" IN THIS SPACE is less than 3, enter "3".	
The "Highest Number Previously Paid For" (Total or Independent) is the highest number found in the appropriate box in column 1.	

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APPLICATION NUMBER	FILING OR 371(C) DATE	FIRST NAMED APPLICANT	ATTY. DOCKET NO./TITLE
16/597,014	10/09/2019	Jared Oehring	047158.100048

CONFIRMATION NO. 4687

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PUBLICATION NOTICE

OC000000116093260

Title:MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT

Publication No.US-2020-0109617-A1
Publication Date:04/09/2020

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The above-identified application will be electronically published as a patent application publication pursuant to 37 CFR 1.211, et seq. The patent application publication number and publication date are set forth above.

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APPLICATION NO.	FILING DATE	FIRST NAMED INVENTOR	ATTORNEY DOCKET NO.	CONFIRMATION NO.
16/597,014	10/09/2019	Jared Oehring	047158.100048	4687

132858 7590 01/10/2020

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EXAMINER	
BOBISH, CHRISTOPHER S	

ART UNIT	PAPER NUMBER
3746	

NOTIFICATION DATE	DELIVERY MODE
01/10/2020	ELECTRONIC

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The time period for reply, if any, is set in the attached communication.

Notice of the Office communication was sent electronically on above-indicated "Notification Date" to the following e-mail address(es):

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Office Action Summary	Application No. 16/597,014	Applicant(s) Oehring et al.	
	Examiner CHRISTOPHER S BOBISH	Art Unit 3746	AIA (FITF) Status Yes

-- The MAILING DATE of this communication appears on the cover sheet with the correspondence address --

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- Failure to reply within the set or extended period for reply will, by statute, cause the application to become ABANDONED (35 U.S.C. § 133). Any reply received by the Office later than three months after the mailing date of this communication, even if timely filed, may reduce any earned patent term adjustment. See 37 CFR 1.704(b).

Status

1)☑ Responsive to communication(s) filed on 10/09/2019.

☐ A declaration(s)/affidavit(s) under **37 CFR 1.130(b)** was/were filed on _____.

2a)☐ This action is **FINAL.** 2b) ☑ This action is non-final.

3)☐ An election was made by the applicant in response to a restriction requirement set forth during the interview on _____; the restriction requirement and election have been incorporated into this action.

4)☐ Since this application is in condition for allowance except for formal matters, prosecution as to the merits is closed in accordance with the practice under *Ex parte Quayle*, 1935 C.D. 11, 453 O.G. 213.

Disposition of Claims*

5) ☑ Claim(s) 1-20 is/are pending in the application.

5a) Of the above claim(s) _____ is/are withdrawn from consideration.

6) ☐ Claim(s) _____ is/are allowed.

7) ☑ Claim(s) 1-20 is/are rejected.

8) ☐ Claim(s) _____ is/are objected to.

9) ☐ Claim(s) _____ are subject to restriction and/or election requirement

* If any claims have been determined allowable, you may be eligible to benefit from the **Patent Prosecution Highway** program at a participating intellectual property office for the corresponding application. For more information, please see http://www.uspto.gov/patents/init_events/pph/index.jsp or send an inquiry to **PPHfeedback@uspto.gov.**

Application Papers

10)☐ The specification is objected to by the Examiner.

11)☑ The drawing(s) filed on 10/09/2019 is/are: a)☑ accepted or b)☐ objected to by the Examiner.

Applicant may not request that any objection to the drawing(s) be held in abeyance. See 37 CFR 1.85(a).

Replacement drawing sheet(s) including the correction is required if the drawing(s) is objected to. See 37 CFR 1.121(d).

Priority under 35 U.S.C. § 119

12)☐ Acknowledgment is made of a claim for foreign priority under 35 U.S.C. § 119(a)-(d) or (f).

Certified copies:

a)☐ All b)☐ Some** c)☐ None of the:

1.☐ Certified copies of the priority documents have been received.

2.☐ Certified copies of the priority documents have been received in Application No. _____.

3.☐ Copies of the certified copies of the priority documents have been received in this National Stage application from the International Bureau (PCT Rule 17.2(a)).

** See the attached detailed Office action for a list of the certified copies not received.

Attachment(s)

1) ☑ Notice of References Cited (PTO-892)

2) ☐ Information Disclosure Statement(s) (PTO/SB/08a and/or PTO/SB/08b) Paper No(s)/Mail Date _____.

3) ☐ Interview Summary (PTO-413) Paper No(s)/Mail Date _____.

4) ☐ Other: _____.

Notice of Pre-AIA or AIA Status

The present application, filed on or after March 16, 2013, is being examined under the first inventor to file provisions of the AIA.

Claim Objections

Claims 4 and 11 are objected to because of the following informalities: The claims include a limitation to a "round switch"; the examiner suggests correcting this to read "*ground* switch". Appropriate correction is required.

Claim Rejections - 35 USC § 112

The following is a quotation of 35 U.S.C. 112(b):
(b) CONCLUSION.—The specification shall conclude with one or more claims particularly pointing out and distinctly claiming the subject matter which the inventor or a joint inventor regards as the invention.

The following is a quotation of 35 U.S.C. 112 (pre-AIA), second paragraph:
The specification shall conclude with one or more claims particularly pointing out and distinctly claiming the subject matter which the applicant regards as his invention.

Claims 7, 9, 14, 18, 19, and their dependents are rejected under 35 U.S.C. 112(b) or 35 U.S.C. 112 (pre-AIA), second paragraph, as being indefinite for failing to particularly point out and distinctly claim the subject matter which the inventor or a joint inventor, or for pre-AIA the applicant regards as the invention.

Claims 7 and 14 recite the limitation "the cable channels" in line 2-3. There is insufficient antecedent basis for this limitation in the claim.

Claim 9 recites the limitation "the *at least one* VFD" in line 18. There is insufficient antecedent basis for this limitation in the claim.

Claim 18 recites the limitation "the at least one turbine generator" in line 4. There is insufficient antecedent basis for this limitation in the claim.

Claim 19 recites the limitation "the at least one turbine generator" in line 2 and 3. There is insufficient antecedent basis for this limitation in the claim.

Claim Rejections - 35 USC § 103

The following is a quotation of 35 U.S.C. 103 which forms the basis for all obviousness rejections set forth in this Office action:

> A patent for a claimed invention may not be obtained, notwithstanding that the claimed invention is not identically disclosed as set forth in section 102, if the differences between the claimed invention and the prior art are such that the claimed invention as a whole would have been obvious before the effective filing date of the claimed invention to a person having ordinary skill in the art to which the claimed invention pertains. Patentability shall not be negated by the manner in which the invention was made.

Claims 1-2, 5-6, 9, 12-13, and 16-17 is/are rejected under 35 U.S.C. 103 as being unpatentable over Morris et al (US PGPub No. 2019/0203572).

Morris teaches:

limitations from claims 1 and 9, a hydraulic fracturing system for fracturing a subterranean formation (FIG. 7. paragraph 77), comprising: a support structure (710) having a first area, a second area, a third area, and a fourth area arranged adjacent one another (see FIG. 7A-7B with various components at different locations on the trailer 710); an electric powered, multi-plunger pump (702) with

up to 15 plungers (paragraph 77), arranged in the first area, the electric powered pump coupled to a well associated with the subterranean formation (see paragraph 39 for example) and powered by at least one electric motor (704, paragraph 79), also arranged in the first area (next to the pumps 702), the electric powered pump configured to pump fluid into a wellbore associated with the well at a high pressure so that the fluid passes from the wellbore into the subterranean formation and fractures the subterranean formation (see paragraph 2); a variable frequency drive (paragraph 77, 79 teaching the use of VFD with the motors; and paragraph 78 teaching the drives being located in the control system 708), arranged in the second area proximate the first area, connected to the at least one electric motor to control the speed of the at least one electric motor (paragraph 77, 79); a transformer (see paragraph 78), arranged in the third area proximate the second area (near controls 708), the transformer positioned within an enclosure (see FIG. 7), the transformer distributing power to the electric pump, the power being received from at least one generator at a voltage higher than an operating voltage of the electric pump (paragraph 77 teaches the pump transport receives power from a mobile source of electricity; paragraph 51 teaches the generator of the mobile power source; paragraph 78 teaching control of the pumps); and a cooling system, arranged in the fourth area proximate the third area, the cooling system providing a cooling fluid to the VFD via one or more headers (Morris does not explicitly teach a cooling system for the VFD on the pump trailer 710; but teaches cooling VFD's in general (paragraph 46) using water cooling for example; it would have been obvious to one of ordinary skill in the art to utilize a similar cooling system on the pump VFD's to maintain the temperature of the components at a safe level during use); and at least one switchgear assembly (112) receiving power from the generator to distribute power via a common bus (paragraph 44);

limitations from claim 2, further comprising: a control system (708; "PLC") arranged in the fourth area, the control system including one or more operating

parameters of the electric pump, VFD, transformer, or cooling system (paragraph 78);

limitations from claim 5, wherein the fourth section (722) is arranged at a higher elevation than the first section, the fourth section associated with a gooseneck portion of a trailer (see FIG. 7B; paragraph 82);

limitations from claims 6 and 13, wherein the support structure is at least one of a trailer, a skid, a pad, a truck bed, or a combination thereof (710; paragraph 78);

limitations from claim 12, further comprising: a transformer service platform (at back end 722) that provides access to the transformer, the transformer service platform positioned at a higher elevation than at least a portion of a base of the electric powered pump (see FIG. 7B; paragraph 78);

limitations from claim 16, further comprising: a human machine interface (1304), positioned proximate the VFD (at 708; paragraph 78 and 88); and a platform cover at least partially covering the humane machine interface and VFD (see FIG. 7 and FIG. 13 showing a box (cover) about the control unit 708);

Claims 3-4, 10-11, and 18-20 is/are rejected under 35 U.S.C. 103 as being unpatentable over Morris et al (US PGPub No. 2019/0203572) as applied to claims 1 above, and in further view of Mori et al (US Patent No. 7,835,140).

Morris teaches a switchgear assembly (112) but does not teach details of the assembly;

Mori teaches:

limitations from claims 3-4, 10-11 and 19, an electric supply system including a switchgear assembly (for example FIG. 1); wherein

the switchgear subassembly having integrated core units configured to operate in a connected position, an open position, or a grounded position (isolator/ground switches DS1/ES1; C. 7 Lines 5-18); and wherein the switchgear subassembly comprises: a busbar (X, Y) shielded, at least partially, by solid insulation (for example GIBT2); an isolating ground switch (E1, E2), enclosed within a tank arranged proximate the busbar (FIG. 2; GIBT1-2); and cable connections for coupling to the switchgear (C. 7 Lines 5-18); such that the bus can isolate the components of the assembly including a power source, switch gear, and load (via isolators DS1-2; C. 6 Line 61 through C. 7 Line 18);

It would have been obvious to one of ordinary skill in the art of switchgears to include common elements such as switches and busbars in the system of Morris, and to insulate the elements as taught by Mori, in order to convey a desired electrical power safely and efficiently to the pumps while maintain a small footprint (C. 2 Lines 55-59 of Mori);

Morris further teaches:

limitations from claim 18, the switch gear (112) receives power from multiple sources and distributes the power to the pumps from the generators (power sources; paragraph 44 and 47), and wherein the power is three phase (see paragraph 79 teaching AC current of which 3-phase is a known variant);

The system of claim 20, wherein the plurality of electric pumps, VFD, and transformer are mounted on a common support structure (710, paragraph 78) and a single cable couples the switchgear to the common support structure (paragraph 44, 78 teaching the use of cables connecting the power to the pumping components; Morris does not teach a particular number of cables, however the examiner maintains that the number of cables is a matter of design choice based upon the number of pumps to be power and the amount of electricity required);

Claims 8 and 15 is/are rejected under 35 U.S.C. 103 as being unpatentable over Morris et al (US PGPub No. 2019/0203572) as applied to claims 1 and 9 above, and in further view of Symchuk (US Patent No. 9,932,799).

Morris teaches cooling VFD's using water cooling and/or ac units, but does not explicitly teach a radiator and glycol;

However, Symchuk teaches a fracturing assembly (FIG. 1) wherein a cooling system includes a radiator and glycol based cooling system (C. 7 Lines 61-67);

It would have been obvious to one of ordinary skill in the art of pumping systems at the time the invention was filed, to substitute one known cooling system for another in order to cool components of the pumping system taught by Morris, such as the use of radiators and glycol as taught by Symchuk, in order to reach an expected result (i.e. cooling of system components).

Claims 7 and 14 is/are rejected under 35 U.S.C. 103 as being unpatentable over Morris et al (US PGPub No. 2019/0203572) as applied to claims 1 and 9 above, and in further view of Oehring et al (US Patent No. 2016/0105022).

Morris does not teach cable trays;

Oehring teaches a fracturing system including pumps (110), motors (114), (VFD (115), and cable trays on a walkable portion (112) for running cables between the components (paragraph 41);

It would have been obvious to one of ordinary skill in the art of fracturing systems at the time of the invention to provide accessible cable trays in the system of Morris, as taught by Oehring, in order to allow for the organization of the various cables in a safe manner along the trailer;

Conclusion

Any inquiry concerning this communication or earlier communications from the examiner should be directed to CHRISTOPHER S BOBISH whose telephone number is (571)270-5289. The examiner can normally be reached on Mon-Fri 9-5.

Examiner interviews are available via telephone, in-person, and video conferencing using a USPTO supplied web-based collaboration tool. To schedule an interview, applicant is encouraged to use the USPTO Automated Interview Request (AIR) at http://www.uspto.gov/interviewpractice.

If attempts to reach the examiner by telephone are unsuccessful, the examiner's supervisor, Devon Kramer can be reached on 571-272-7118. The fax phone number for the organization where this application or proceeding is assigned is 571-273-8300.

Information regarding the status of an application may be obtained from the Patent Application Information Retrieval (PAIR) system. Status information for published applications may be obtained from either Private PAIR or Public PAIR. Status information for unpublished applications is available through Private PAIR only. For more information about the PAIR system, see http://pair-direct.uspto.gov. Should you have questions on access to the Private PAIR system, contact the Electronic Business Center (EBC) at 866-217-9197 (toll-free). If you would like assistance from a USPTO Customer Service Representative or access to the automated information system, call 800-786-9199 (IN USA OR CANADA) or 571-272-1000.

/CHRISTOPHER S BOBISH/
Examiner, Art Unit 3746

Notice of References Cited	Application/Control No. 16/597,014	Applicant(s)/Patent Under Reexamination Oehring et al.	
	Examiner CHRISTOPHER S BOBISH	Art Unit 3746	Page 1 of 2

U.S. PATENT DOCUMENTS

*		Document Number Country Code-Number-Kind Code	Date MM-YYYY	Name	CPC Classification	US Classification
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*	B	US-20170222409-A1	08-2017	Oehring; Jared	E21B41/00	1/1
*	C	US-20170114625-A1	04-2017	NORRIS; Mark A.	E21B47/0007	1/1
*	D	US-20170051732-A1	02-2017	Hemandez; Jennifer	F04B17/06	1/1
*	E	US-20190203572-A1	07-2019	Morris; Jeffrey G.	E21B43/26	1/1
*	F	US-20150114652-A1	04-2015	Lestz; Robert S.	E21B43/26	166/308.1
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*		Document Number Country Code-Number-Kind Code	Date MM-YYYY	Country	Name	CPC Classification
	N					
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	P					
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	S					
	T					

NON-PATENT DOCUMENTS

*		Include as applicable: Author, Title Date, Publisher, Edition or Volume, Pertinent Pages)
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	W	
	X	

*A copy of this reference is not being furnished with this Office action. (See MPEP § 707.05(a).)
Dates in MM-YYYY format are publication dates. Classifications may be US or foreign.

Notice of References Cited	Application/Control No. 16/597,014	Applicant(s)/Patent Under Reexamination Oehring et al.	
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U.S. PATENT DOCUMENTS

*		Document Number Country Code-Number-Kind Code	Date MM-YYYY	Name	CPC Classification	US Classification
*	A	US-20170030177-A1	02-2017	OEHRING; Jared	E21B7/02	1/1
*	B	US-20150252661-A1	09-2015	Glass; Cory	E21B43/267	166/308.1
*	C	US-20150027712-A1	01-2015	Vicknair; Bruce A	E21B43/162	166/305.1
*	D	US-20140219824-A1	08-2014	Burnette; Blake	F04B23/06	417/53
*	E	US-20140095114-A1	04-2014	Thomeer; Hubertus V.	G06Q10/20	702/187
*	F	US-10393108-B2	08-2019	Chong; Jonathan Wun Shiung	F04B49/20	1/1
*	G	US-10378326-B2	08-2019	Morris; Jeffrey G.	F04B23/04	1/1
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*	K	US-20160105022-A1	04-2016	Oehring; Jared	E21B43/26	700/293
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	M					

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NON-PATENT DOCUMENTS

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*A copy of this reference is not being furnished with this Office action. (See MPEP § 707.05(a).)
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Index of Claims	Application/Control No.	Applicant(s)/Patent Under Reexamination
	16/597,014	Oehring et al.
	Examiner	**Art Unit**
	CHRISTOPHER S BOBISH	3746

✓	Rejected	-	Cancelled	N	Non-Elected	A	Appeal
=	Allowed	÷	Restricted	I	Interference	O	Objected

CLAIMS

☐ Claims renumbered in the same order as presented by applicant ☐ CPA ☐ T.D. ☐ R.1.47

CLAIM		DATE								
Final	Original	12/20/2019								
	1	✓								
	2	✓								
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	4	✓								
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	19	✓								
	20	✓								

Search Notes	Application/Control No.	Applicant(s)/Patent Under Reexamination
	16/597,014	Oehring et al.
	Examiner	Art Unit
	CHRISTOPHER S BOBISH	3746

CPC - Searched*		
Symbol	Date	Examiner
F04B17/06	12/10/2019	CSB
F02B63/047, 06	12/10/2019	CSB

CPC Combination Sets - Searched*		
Symbol	Date	Examiner

US Classification - Searched*			
Class	Subclass	Date	Examiner

* See search history printout included with this form or the SEARCH NOTES box below to determine the scope of the search.

Search Notes		
Search Notes	Date	Examiner
Inventor Name Search	12/10/2019	CSB
EAST Search	12/10/2019	CSB

Interference Search			
US Class/CPC Symbol	US Subclass/CPC Group	Date	Examiner

/CHRISTOPHER S BOBISH/ Examiner, Art Unit 3746	

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EAST Search History

EAST Search History (Prior Art)

Ref #	Hits	Search Query	DBs	Default Operator	Plurals	Time Stamp
S1	68	((("OEHRING") near3 ("Jared")) OR (("HINDERLITER") near3 ("Brandon")) OR (("ROBINSON") near3 ("Lon"))).INV.	US-PGPUB; USPAT; USOCR; EPO; JPO; DERWENT	OR	ON	2019/12/10 11:53
S2	28	("20040040746" | "20060052903" | "20110247878" | "20140095114" | "20140379300" | "20150075778" | "20150217672" | "20160208595" | "20160230524" | "20170022807" | "20170037717" | "20170114625" | "20170292513" | "20170328179" | "4432064" | "5006044").PN.	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 11:57
S5	126	("2183364" | "2220622" | "2248051" | "2753940" | "3061039" | "3066503" | "3334495" | "3722595" | "3764233" | "3773140" | "3837179" | "3849662" | "3881551" | "4037431" | "4151575" | "4226299" | "4265266" | "4442665" | "4456092" | "4506982" | "4512387" | "4529887" | "4538916" | "4676063" | "4793386" | "4845981" | "4922463" | "5025861" | "5130628" | "5131472" | "5422550" | "5548093" | "5590976" | "5655361" | "5736838" | "5790972" | "5865247" | "5879137" | "5894888" | "5907970" | "6138764" | "6142878" | "6164910" | "6202702" | "6254462" | "6271637" | "6315523" | "6477852" | "6491098" | "6529135" | "6776227" | "6802690" | "6808303" | "6931310" | "7104233" | "7170262" | "7173399" | "7312593" | "7336514" | "7445041" | "7494263" | "7500642" | "7525264" | "7563076" | "7675189" | "7683499" | "7717193" | "7755310" | "7807048" | "7845413" | "7977824" | "8037936" | "8054084" | "8083504" | "8096891" | "8139383" | "8146665" | "8154419" | "8232892" | "8261528" | "8272439" | "8310272" | "8354817" | "8474521" | "8534235" | "8573303" | "8596056" | "8616274" | "8692408" | "8727068" | "8760657" | "8774972" | "8789601" | "8807960" | "8838341" | "8857506" | "8899940" | "8905056" | "8905138" | "8997904" | "9018881" | "9051822" | "9067182" | "9103193" | "9121257" | "9140110" | "9160168" | "9322239" | "9366114" | "9410410" | "9450385" | "9475020" | "9475021" | "9534473" |	US-PGPUB; USPAT	OR	ON	2019/12/10 11:58

		"9562420" | "9587649" | "9611728" | "9650871" | "9650879" | "9738461" | "9745840" | "9840901" | "9863228" | "9893500" | "9970278" | "9995218").PN.				
S3	1	("20140255214").PN.	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 11:58
S6	206	("10008880" | "10232332" | "10254732" | "10280724" | "20030056514" | "20040167738" | "20080264625" | "20100038907" | "20100045109" | "20120049625" | "20140060658" | "20140219824" | "20140255214" | "20150027712" | "20150136043" | "20150211512" | "20160105022" | "20160265457" | "20160281484" | "20160290563" | "20170096885" | "20170159570" | "20170218727" | "20170234250" | "20180028992" | "20190010793" | "20190063309" | "20190112910" | "20190120024" | "20190162061" | "20190169971" | "20190178235" | "20190211661" | "20190245348" | "5172009" | "5755096" | "6484490" | "7581379" | "8616005" | "20060260331" | "20080236818" | "20080264640" | "20090090504" | "20100101785" | "20100200224" | "20110166046" | "20150330172" | "20170241221" | "9175554" | "9206684" | "9458687" | "20050274508" | "20070131410" | "20070277982" | "20090045782" | "20140277772" | "20140290768" | "20150097504" | "20160102537" | "20160341281" | "20170051732" | "20180038216" | "20180320483" | "20190003329" | "4100822" | "5189388" | "6208098" | "8851860" | "20040040746" | "20060052903" | "20110247878" | "20140095114" | "20140379300" | "20150075778" | "20150217672" | "20160208595" | "20160230524" | "20170022807" | "20170037717" | "20170114625" | "20170292513" | "20170328179" | "4432064" | "5006044" | "10020711" | "10036238" | "10107086" | "10119381" | "1671436" | "20020169523" | "20030138327" | "20040000077" | "20040102109" | "20050116541" | "20070187163" | "20070201305" | "20070226089" | "20070278140" | "20080112802" | "20080137266" | "20080208478" | "20080217024" | "20080264649" | "20090065299" | "20090078410" | "20090093317" | "20090095482" | "20090153354" | "20090188181" | "20090200035" | "20090260826" | "20090308602" |	US-PGPUB; USPAT	OR	ON	2019/12/10 13:34

		"20100000508" | "20100019574" | "20100051272" | "20100132949" | "20100146981" | "20100172202" | "20100250139" | "20100293973" | "20100303655" | "20100322802" | "20110005757" | "20110017468" | "20110061855" | "20110085924" | "20110272158" | "20120018016" | "20120085541" | "20120127635" | "20120205301" | "20120205400" | "20120232728" | "20120255734" | "20130009469" | "20130025706" | "20130175038" | "20130175039" | "20130199617" | "20130233542" | "20130306322" | "20130341029" | "20130343858" | "20140000899" | "20140010671" | "20140054965" | "20140096974" | "20140124162" | "20140138079" | "20140174717" | "20140246211" | "20140251623" | "20150068724" | "20150068754" | "20150083426" | "20150114652" | "20150144336" | "20150159911" | "20150175013" | "20150176386" | "20150211524" | "20150225113" | "20150252661" | "20150300145" | "20150314225" | "20160032703" | "20160160889" | "20160177675" | "20160177678" | "20160186531" | "20160208592" | "20160208593" | "20160208594" | "20160221220" | "20160230525" | "20160258267" | "20160273328" | "20160290114" | "20160312108" | "20160319650" | "20160326854" | "20160326855" | "20160348479" | "20160349728" | "20160369609" | "20170021318" | "20170022788" | "20170028368" | "20170030177" | "20170030178" | "20170036178" | "20170037718" | "20170104389" | "20170145918" | "20170218843" | "20170222409" | "20170226839" | "20170226842" | "20170259227" | "20170313499" | "20170314380" | "20170369258" | "20180156210" | "20180183219" | "20180258746" | "20180274446").PN.				
S8	1046	F04B17/06.cpc.	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 13:36
S10	504	F02B63/047.cpc.	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 13:41
S9	0	(15/689484).APP.	USPAT; USOCR	OR	ON	2019/12/10 13:41
S11	16	("20090015021" | "20130106114" | "20150184591" | "20160333777" | "3791682" | "4317556" | "5517822" | "6765304" | "6786051" | "7036318" |	US-PGPUB; USPAT; USOCR	OR	ON	2019/12/10 13:45

		"7267319" | "8587136" | "8872366" | "9103193" | "9121257" | "9140110").PN. OR ("10371012").URPN.				
S16	3575718	(skid or pad or bed or trailer)	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 13:48
S17	16955	(generator and pump and (motor or engine) and transformer)	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 13:48
S15	109473	(fracking or fracturing)	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 13:48
S19	733	S18 and (cool$4)	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 13:49
S18	784	S15 and S16 and S17	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 13:49
S21	5	S19 and bus$bar	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:20
S23	172	S19 and triplex	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:21
S22	0	S19 and multi$plunger	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:21
S24	18	(US-20190063309-$ or US-20190003329-$ or US-20170222409-$ or US-20170114625-$ or US-20170104389-$ or US-20170051732-$ or US-20170030177-$ or US-20150252661-$ or US-20150027712-$ or US-20140219824-$ or US-20140095114-$ or US-20190203572-$ or US-20150114652-$).did. or (US-10393108-$ or US-10378326-$ or US-10371012-$ or US-10227854-$ or US-9103193-$).did.	US-PGPUB; USPAT	OR	ON	2019/12/10 14:24
S25	1	S24 and bus$bar	US-PGPUB; USPAT; USOCR;	OR	ON	2019/12/10 14:25

			FPRS			
S27	2	S24 and radiator and glycol	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:46
S26	5	S24 and radiator	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:46
S28	0	S19 and radiator with glycol	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:47
S30	82	S29 and radiator and glycol	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:48
S29	23162	S15 and S16	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:48
S31	2	S29 and radiator with glycol	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:49
S33	0	S29 and switch$gear and busbar	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:50
S32	46	S29 and switch$gear	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:50
S36	4	round adj switch with tank	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:51
S35	435	round adj switch	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:51
S34	0	isolat$4 adj round adj switch	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:51
S37	22	round adj switch same tank	US-PGPUB; USPAT; USOCR;	OR	ON	2019/12/10 14:52

			FPRS			
S39	77	generator same switch$gear same busbar	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:54
S40	15	generator same switch$gear same (busbar with insulat$4)	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:54
S38	1814	generator same switch$gear	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 14:54
S41	15	generator same switch$gear same (isolator)	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 15:02
S42	52	isolat$4 adj ground adj switch	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/10 15:10
S43	0	(2006/0216147).CCLS.	US-PGPUB; USPAT; USOCR	OR	OFF	2019/12/16 15:08
S44	1	("20060216147").PN.	US-PGPUB; USPAT; USOCR	OR	OFF	2019/12/16 15:11
L7	1481	F02B63/06.cpc.	US-PGPUB; USPAT; USOCR; FPRS	OR	ON	2019/12/20 14:16

12/20/2019 2:18:06 PM
C:\Users\cbobish\Documents\EAST\Workspaces\ModularSwitchgearSystem.wsp

Bibliographic Data

Application No: 16/597,014

Foreign Priority claimed: ○ Yes ◉ No

35 USC 119 (a-d) conditions met: ☐ Yes ☑ No ☐ Met After Allowance

Verified and Acknowledged: /CHRISTOPHER S BOBISH/ Examiner's Signature | Initials

Title: MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT

FILING or 371(c) DATE	CLASS	GROUP ART UNIT	ATTORNEY DOCKET NO.
10/09/2019	417	3746	047158.100048
RULE			

APPLICANTS

U.S. Well Services, LLC, Houston, TX, UNITED STATES

INVENTORS

Jared Oehring Houston, TX, UNITED STATES

Brandon N. Hinderliter Houston, TX, UNITED STATES

Lon Robinson Houston, TX, UNITED STATES

CONTINUING DATA

This application has PRO of 62743360 10/09/2018

This application has PRO of 62743299 10/09/2018

FOREIGN APPLICATIONS

IF REQUIRED, FOREIGN LICENSE GRANTED**

10/25/2019

STATE OR COUNTRY

UNITED STATES

ADDRESS

Hogan Lovells US LLP
609 Main Street
Suite 4200
Houston, TX 77002
UNITED STATES

FILING FEE RECEIVED

$5,860

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United States Patent and Trademark Office
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APPLICATION NO.	FILING DATE	FIRST NAMED INVENTOR	ATTORNEY DOCKET NO.	CONFIRMATION NO.
16/597,014	10/09/2019	Jared Oehring	047158.100048	4687

132858 7590 10/31/2019

Hogan Lovells US LLP
609 Main Street
Suite 4200
Houston, TX 77002

EXAMINER	
ART UNIT	PAPER NUMBER
3674	
NOTIFICATION DATE	DELIVERY MODE
10/31/2019	ELECTRONIC

Please find below and/or attached an Office communication concerning this application or proceeding.

The time period for reply, if any, is set in the attached communication.

Notice of the Office communication was sent electronically on above-indicated "Notification Date" to the following e-mail address(es):

hlusdocketing@hoganlovells.com
monica.williams@hoganlovells.com
stephanie.mcdonough@hoganlovells.com

Decision Granting Request for Prioritized Examination (Track I)	**Application No.** 16/597,014	**Applicant(s)** Oehring et al.	
	Examiner BRIAN W BROWN	**Art Unit** OPET	**AIA (FITF) Status** Yes

1. THE REQUEST FILED 09 October 2019 IS **GRANTED** .

The above-identified application has met the requirements for prioritized examination

A. ☑ for an original nonprovisional application (Track I).
B. ☐ for an application undergoing continued examination (RCE).

2. **The above-identified application will undergo prioritized examination**. The application will be accorded special status throughout its entire course of prosecution until one of the following occurs:

A. filing a **petition for extension of time** to extend the time period for filing a reply;

B. filing an **amendment to amend the application to contain more than four independent claims, more than thirty total claims** , or a multiple dependent claim;

C. filing a **request for continued examination** ;

D. filing a notice of appeal;

E. filing a request for suspension of action;

F. mailing of a notice of allowance;

G. mailing of a final Office action;

H. completion of examination as defined in 37 CFR 41.102; or

I. abandonment of the application.

Telephone inquiries with regard to this decision should be directed to BRIAN BROWN at (571)272-5338.

In his/her absence, calls may be directed to Petition Help Desk at (571) 272-3282.

/BRIAN W BROWN/ Petitions Examiner, OPET	

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APPLICATION NUMBER	FILING or 371(c) DATE	GRP ART UNIT	FIL FEE REC'D	ATTY.DOCKET.NO	TOT CLAIMS	IND CLAIMS
16/597,014	10/09/2019	3674	1880	047158.100048	20	3

CONFIRMATION NO. 4687

132858
Hogan Lovells US LLP
609 Main Street
Suite 4200
Houston, TX 77002

FILING RECEIPT

OC000000112219238

Date Mailed: 10/29/2019

Receipt is acknowledged of this non-provisional utility patent application. The application will be taken up for examination in due course. Applicant will be notified as to the results of the examination. Any correspondence concerning the application must include the following identification information: the U.S. APPLICATION NUMBER, FILING DATE, NAME OF FIRST INVENTOR, and TITLE OF INVENTION. Fees transmitted by check or draft are subject to collection.

Please verify the accuracy of the data presented on this receipt. If an error is noted on this Filing Receipt, please submit a written request for a corrected Filing Receipt, including a properly marked-up ADS showing the changes with strike-through for deletions and underlining for additions. If you received a "Notice to File Missing Parts" or other Notice requiring a response for this application, please submit any request for correction to this Filing Receipt with your reply to the Notice. When the USPTO processes the reply to the Notice, the USPTO will generate another Filing Receipt incorporating the requested corrections provided that the request is grantable.

Inventor(s)

Jared Oehring, Houston, TX;
Brandon N. Hinderliter, Houston, TX;
Lon Robinson, Houston, TX;

Applicant(s)

U.S. Well Services, LLC, Houston, TX;

Assignment For Published Patent Application

U.S. Well Services, LLC, Houston, TX

Power of Attorney: None

Domestic Priority data as claimed by applicant

This appln claims benefit of 62/743,299 10/09/2018
and claims benefit of 62/743,360 10/09/2018

Foreign Applications for which priority is claimed (You may be eligible to benefit from the **Patent Prosecution Highway** program at the USPTO. Please see http://www.uspto.gov for more information.) - None.
Foreign application information must be provided in an Application Data Sheet in order to constitute a claim to foreign priority. See 37 CFR 1.55 and 1.76.

Permission to Access Application via Priority Document Exchange: Yes

Permission to Access Search Results: Yes

Applicant may provide or rescind an authorization for access using Form PTO/SB/39 or Form PTO/SB/69 as appropriate.

If Required, Foreign Filing License Granted: 10/25/2019

The country code and number of your priority application, to be used for filing abroad under the Paris Convention, is **US 16/597,014**

Projected Publication Date: 04/09/2020

Non-Publication Request: No

Early Publication Request: No

Title

MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT

Preliminary Class

166

Statement under 37 CFR 1.55 or 1.78 for AIA (First Inventor to File) Transition Applications: No

PROTECTING YOUR INVENTION OUTSIDE THE UNITED STATES

Since the rights granted by a U.S. patent extend only throughout the territory of the United States and have no effect in a foreign country, an inventor who wishes patent protection in another country must apply for a patent in a specific country or in regional patent offices. Applicants may wish to consider the filing of an international application under the Patent Cooperation Treaty (PCT). An international (PCT) application generally has the same effect as a regular national patent application in each PCT-member country. The PCT process **simplifies** the filing of patent applications on the same invention in member countries, but **does not result** in a grant of "an international patent" and does not eliminate the need of applicants to file additional documents and fees in countries where patent protection is desired.

Almost every country has its own patent law, and a person desiring a patent in a particular country must make an application for patent in that country in accordance with its particular laws. Since the laws of many countries differ in various respects from the patent law of the United States, applicants are advised to seek guidance from specific foreign countries to ensure that patent rights are not lost prematurely.

Applicants also are advised that in the case of inventions made in the United States, the Director of the USPTO must issue a license before applicants can apply for a patent in a foreign country. The filing of a U.S. patent application serves as a request for a foreign filing license. The application's filing receipt contains further information and guidance as to the status of applicant's license for foreign filing.

Applicants may wish to consult the USPTO booklet, "General Information Concerning Patents" (specifically, the section entitled "Treaties and Foreign Patents") for more information on timeframes and deadlines for filing foreign patent applications. The guide is available either by contacting the USPTO Contact Center at 800-786-9199, or it can be viewed on the USPTO website at http://www.uspto.gov/web/offices/pac/doc/general/index.html.

For information on preventing theft of your intellectual property (patents, trademarks and copyrights), you may wish to consult the U.S. Government website, http://www.stopfakes.gov. Part of a Department of Commerce initiative, this website includes self-help "toolkits" giving innovators guidance on how to protect intellectual property in specific

countries such as China, Korea and Mexico. For questions regarding patent enforcement issues, applicants may call the U.S. Government hotline at 1-866-999-HALT (1-866-999-4258).

LICENSE FOR FOREIGN FILING UNDER

Title 35, United States Code, Section 184

Title 37, Code of Federal Regulations, 5.11 & 5.15

GRANTED

The applicant has been granted a license under 35 U.S.C. 184, if the phrase "IF REQUIRED, FOREIGN FILING LICENSE GRANTED" followed by a date appears on this form. Such licenses are issued in all applications where the conditions for issuance of a license have been met, regardless of whether or not a license may be required as set forth in 37 CFR 5.15. The scope and limitations of this license are set forth in 37 CFR 5.15(a) unless an earlier license has been issued under 37 CFR 5.15(b). The license is subject to revocation upon written notification. The date indicated is the effective date of the license, unless an earlier license of similar scope has been granted under 37 CFR 5.13 or 5.14.

This license is to be retained by the licensee and may be used at any time on or after the effective date thereof unless it is revoked. This license is automatically transferred to any related applications(s) filed under 37 CFR 1.53(d). This license is not retroactive.

The grant of a license does not in any way lessen the responsibility of a licensee for the security of the subject matter as imposed by any Government contract or the provisions of existing laws relating to espionage and the national security or the export of technical data. Licensees should apprise themselves of current regulations especially with respect to certain countries, of other agencies, particularly the Office of Defense Trade Controls, Department of State (with respect to Arms, Munitions and Implements of War (22 CFR 121-128)); the Bureau of Industry and Security, Department of Commerce (15 CFR parts 730-774); the Office of Foreign AssetsControl, Department of Treasury (31 CFR Parts 500+) and the Department of Energy.

NOT GRANTED

No license under 35 U.S.C. 184 has been granted at this time, if the phrase "IF REQUIRED, FOREIGN FILING LICENSE GRANTED" DOES NOT appear on this form. Applicant may still petition for a license under 37 CFR 5.12, if a license is desired before the expiration of 6 months from the filing date of the application. If 6 months has lapsed from the filing date of this application and the licensee has not received any indication of a secrecy order under 35 U.S.C. 181, the licensee may foreign file the application pursuant to 37 CFR 5.15(b).

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The United States represents the largest, most dynamic marketplace in the world and is an unparalleled location for business investment, innovation, and commercialization of new technologies. The U.S. offers tremendous resources and advantages for those who invest and manufacture goods here. Through SelectUSA, our nation works to promote and facilitate business investment. SelectUSA provides information assistance to the international investor community; serves as an ombudsman for existing and potential investors; advocates on behalf of U.S. cities, states, and regions competing for global investment; and counsels U.S. economic development organizations on investment attraction best practices. To learn more about why the United States is the best country in the world to develop

technology, manufacture products, deliver services, and grow your business, visit http://www.SelectUSA.gov or call +1-202-482-6800.

LIBERTY EXHIBIT 1002, Page 2154

PATENT APPLICATION FEE DETERMINATION RECORD

Substitute for Form PTO-875

Application or Docket Number: 16/597,014

APPLICATION AS FILED - PART I

FOR	(Column 1) NUMBER FILED	(Column 2) NUMBER EXTRA	SMALL ENTITY RATE($)	SMALL ENTITY FEE($)	OR	OTHER THAN SMALL ENTITY RATE($)	OTHER THAN SMALL ENTITY FEE($)
BASIC FEE (37 CFR 1.16(a), (b), or (c))	N/A	N/A	N/A			N/A	300
SEARCH FEE (37 CFR 1.16(k), (i), or (m))	N/A	N/A	N/A			N/A	660
EXAMINATION FEE (37 CFR 1.16(o), (p), or (q))	N/A	N/A	N/A			N/A	760
TOTAL CLAIMS (37 CFR 1.16(i))	20 minus 20 =	*			OR	x 100 =	0.00
INDEPENDENT CLAIMS (37 CFR 1.16(h))	3 minus 3 =	*				x 460 =	0.00
APPLICATION SIZE FEE (37 CFR 1.16(s))	If the specification and drawings exceed 100 sheets of paper, the application size fee due is $310 ($155 for small entity) for each additional 50 sheets or fraction thereof. See 35 U.S.C. 41(a)(1)(G) and 37 CFR 1.16(s).						0.00
MULTIPLE DEPENDENT CLAIM PRESENT (37 CFR 1.16(j))							0.00
* If the difference in column 1 is less than zero, enter "0" in column 2.			TOTAL			TOTAL	1720

APPLICATION AS AMENDED - PART II

AMENDMENT A

	(Column 1) CLAIMS REMAINING AFTER AMENDMENT		(Column 2) HIGHEST NUMBER PREVIOUSLY PAID FOR	(Column 3) PRESENT EXTRA	SMALL ENTITY RATE($)	SMALL ENTITY ADDITIONAL FEE($)	OR	OTHER THAN SMALL ENTITY RATE($)	OTHER THAN SMALL ENTITY ADDITIONAL FEE($)
Total (37 CFR 1.16(i))	*	Minus	**	=	x =		OR	x =	
Independent (37 CFR 1.16(h))	*	Minus	***	=	x =		OR	x =	
Application Size Fee (37 CFR 1.16(s))									
FIRST PRESENTATION OF MULTIPLE DEPENDENT CLAIM (37 CFR 1.16(j))							OR		
					TOTAL ADD'L FEE		OR	TOTAL ADD'L FEE	

AMENDMENT B

	(Column 1) CLAIMS REMAINING AFTER AMENDMENT		(Column 2) HIGHEST NUMBER PREVIOUSLY PAID FOR	(Column 3) PRESENT EXTRA	RATE($)	ADDITIONAL FEE($)		RATE($)	ADDITIONAL FEE($)
Total (37 CFR 1.16(i))	*	Minus	**	=	x =		OR	x =	
Independent (37 CFR 1.16(h))	*	Minus	***	=	x =		OR	x =	
Application Size Fee (37 CFR 1.16(s))									
FIRST PRESENTATION OF MULTIPLE DEPENDENT CLAIM (37 CFR 1.16(j))							OR		
					TOTAL ADD'L FEE		OR	TOTAL ADD'L FEE	

* If the entry in column 1 is less than the entry in column 2, write "0" in column 3.
** If the "Highest Number Previously Paid For" IN THIS SPACE is less than 20, enter "20".
*** If the "Highest Number Previously Paid For" IN THIS SPACE is less than 3, enter "3".
The "Highest Number Previously Paid For" (Total or Independent) is the highest found in the appropriate box in column 1.

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APPLICATION NUMBER	FILING OR 371(C) DATE	FIRST NAMED APPLICANT	ATTY. DOCKET NO./TITLE
16/597,014	10/09/2019	Jared Oehring	047158.100048

CONFIRMATION NO. 4687

132858
Hogan Lovells US LLP
609 Main Street
Suite 4200
Houston, TX 77002

INFORMAL NOTICE

OC000000112219239

Date Mailed: 10/29/2019

INFORMATIONAL NOTICE TO APPLICANT

Applicant is notified that the above-identified application contains the deficiencies noted below. No period for reply is set forth in this notice for correction of these deficiencies. However, if a deficiency relates to the inventor's oath or declaration, the applicant must file an oath or declaration in compliance with 37 CFR 1.63, or a substitute statement in compliance with 37 CFR 1.64, executed by or with respect to each actual inventor no later than the expiration of the time period set in the "Notice of Allowability" to avoid abandonment. See 37 CFR 1.53(f).

The item(s) indicated below are also required and should be submitted with any reply to this notice to avoid further processing delays.

- A properly executed inventor's oath or declaration has not been received for the following inventor(s):
  Jared Oehring
  Brandon N. Hinderliter
  Lon Robinson

Questions about the contents of this notice and the requirements it sets forth should be directed to the Office of Data Management, Application Assistance Unit, at **(571) 272-4000** or **(571) 272-4200** or **1-888-786-0101**.

/fasrat/

United States Patent and Trademark Office

Office of the Chief Financial Officer

Document Code:WFEE

User :C41739

Sale Accounting Date:10/25/2019

Sale Item Reference Number	Effective Date
16597014	10/09/2019

Document Number	Fee Code	Fee Code Description	Amount Paid	Payment Method
I20190O913192604	1051	LATE FILING FEE FOR OATH OR DECLARATION	$160.00	Deposit Account

Doc Code: TRACK1.REQ
Document Description: TrackOne Request

PTO/AIA/424 (04-14)

CERTIFICATION AND REQUEST FOR PRIORITIZED EXAMINATION UNDER 37 CFR 1.102(e) (Page 1 of 1)

First Named Inventor:	Jared Oehring	Nonprovisional Application Number (if known):	
Title of Invention:	Modular Switchgear System and Power Distribution For Electric Oilfield...		

APPLICANT HEREBY CERTIFIES THE FOLLOWING AND REQUESTS PRIORITIZED EXAMINATION FOR THE ABOVE-IDENTIFIED APPLICATION.

1. The processing fee set forth in 37 CFR 1.17(i)(1) and the prioritized examination fee set forth in 37 CFR 1.17(c) have been filed with the request. The publication fee requirement is met because that fee, set forth in 37 CFR 1.18(d), is currently $0. The basic filing fee, search fee, and examination fee are filed with the request or have been already been paid. I understand that any required excess claims fees or application size fee must be paid for the application.

2. I understand that the application may not contain, or be amended to contain, more than four independent claims, more than thirty total claims, or any multiple dependent claims, and that any request for an extension of time will cause an outstanding Track I request to be dismissed.

3. The applicable box is checked below:

I. ☑ Original Application (Track One) - Prioritized Examination under § 1.102(e)(1)

i. (a) The application is an original nonprovisional utility application filed under 35 U.S.C. 111(a). This certification and request is being filed with the utility application via EFS-Web.

---OR---

(b) The application is an original nonprovisional plant application filed under 35 U.S.C. 111(a). This certification and request is being filed with the plant application in paper.

ii. An executed inventor's oath or declaration under 37 CFR 1.63 or 37 CFR 1.64 for each inventor, **or** the application data sheet meeting the conditions specified in 37 CFR 1.53(f)(3)(i) is filed with the application.

II. ☐ Request for Continued Examination - Prioritized Examination under § 1.102(e)(2)

i. A request for continued examination has been filed with, or prior to, this form.
ii. If the application is a utility application, this certification and request is being filed via EFS-Web.
iii. The application is an original nonprovisional utility application filed under 35 U.S.C. 111(a), or is a national stage entry under 35 U.S.C. 371.
iv. This certification and request is being filed prior to the mailing of a first Office action responsive to the request for continued examination.
v. No prior request for continued examination has been granted prioritized examination status under 37 CFR 1.102(e)(2).

Signature /Taylor P. Evans/	Date 2019-10-09
Name (Print/Typed) Taylor P. Evans	Practitioner Registration Number 60506

Note: *This form must be signed in accordance with 37 CFR 1.33. See 37 CFR 1.4(d) for signature requirements and certifications. Submit multiple forms if more than one signature is required.**

☑ *Total of 1 forms are submitted.

Privacy Act Statement

The **Privacy Act of 1974 (P.L. 93-579)** requires that you be given certain information in connection with your submission of the attached form related to a patent application or patent. Accordingly, pursuant to the requirements of the Act, please be advised that: (1) the general authority for the collection of this information is 35 U.S.C. 2(b)(2); (2) furnishing of the information solicited is voluntary; and (3) the principal purpose for which the information is used by the U.S. Patent and Trademark Office is to process and/or examine your submission related to a patent application or patent. If you do not furnish the requested information, the U.S. Patent and Trademark Office may not be able to process and/or examine your submission, which may result in termination of proceedings or abandonment of the application or expiration of the patent.

The information provided by you in this form will be subject to the following routine uses:

1. The information on this form will be treated confidentially to the extent allowed under the Freedom of Information Act (5 U.S.C. 552) and the Privacy Act (5 U.S.C 552a). Records from this system of records may be disclosed to the Department of Justice to determine whether disclosure of these records is required by the Freedom of Information Act.
2. A record from this system of records may be disclosed, as a routine use, in the course of presenting evidence to a court, magistrate, or administrative tribunal, including disclosures to opposing counsel in the course of settlement negotiations.
3. A record in this system of records may be disclosed, as a routine use, to a Member of Congress submitting a request involving an individual, to whom the record pertains, when the individual has requested assistance from the Member with respect to the subject matter of the record.
4. A record in this system of records may be disclosed, as a routine use, to a contractor of the Agency having need for the information in order to perform a contract. Recipients of information shall be required to comply with the requirements of the Privacy Act of 1974, as amended, pursuant to 5 U.S.C. 552a(m).
5. A record related to an International Application filed under the Patent Cooperation Treaty in this system of records may be disclosed, as a routine use, to the International Bureau of the World Intellectual Property Organization, pursuant to the Patent Cooperation Treaty.
6. A record in this system of records may be disclosed, as a routine use, to another federal agency for purposes of National Security review (35 U.S.C. 181) and for review pursuant to the Atomic Energy Act (42 U.S.C. 218(c)).
7. A record from this system of records may be disclosed, as a routine use, to the Administrator, General Services, or his/her designee, during an inspection of records conducted by GSA as part of that agency's responsibility to recommend improvements in records management practices and programs, under authority of 44 U.S.C. 2904 and 2906. Such disclosure shall be made in accordance with the GSA regulations governing inspection of records for this purpose, and any other relevant (*i.e.*, GSA or Commerce) directive. Such disclosure shall not be used to make determinations about individuals.
8. A record from this system of records may be disclosed, as a routine use, to the public after either publication of the application pursuant to 35 U.S.C. 122(b) or issuance of a patent pursuant to 35 U.S.C. 151. Further, a record may be disclosed, subject to the limitations of 37 CFR 1.14, as a routine use, to the public if the record was filed in an application which became abandoned or in which the proceedings were terminated and which application is referenced by either a published application, an application open to public inspection or an issued patent.
9. A record from this system of records may be disclosed, as a routine use, to a Federal, State, or local law enforcement agency, if the USPTO becomes aware of a violation or potential violation of law or regulation.

PTO/AIA/15 (10-17)
Approved for use through 11/30/2020. OMB 0651-0032
U.S. Patent and Trademark Office; U.S. DEPARTMENT OF COMMERCE
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UTILITY PATENT APPLICATION TRANSMITTAL

(Only for new nonprovisional applications under 37 CFR 1.53(b))

Attorney Docket No.	047158.100048
First Named Inventor	Jared Oehring
Title	Modular Switchgear System and ...
Priority Mail Express® Label No.	

APPLICATION ELEMENTS

See MPEP chapter 600 concerning utility patent application contents.

1. [✔] **Fee Transmittal Form** (PTO/SB/17 or equivalent)
2. [ ] **Applicant asserts small entity status.** See 37 CFR 1.27
3. [ ] **Applicant certifies micro entity status.** See 37 CFR 1.29. Applicant must attach form PTO/SB/15A or B or equivalent.
4. [✔] **Specification** [*Total Pages* 15] Both the claims and abstract must start on a new page. *(See MPEP § 608.01(a) for information on the preferred arrangement)*
5. [✔] **Drawing(s)** (35 U.S.C. 113) [*Total Sheets* 36]
6. **Inventor's Oath or Declaration** [*Total Pages*] *(including substitute statements under 37 CFR 1.64 and assignments serving as an oath or declaration under 37 CFR 1.63(e))*
   a. [ ] Newly executed (original or copy)
   b. [ ] A copy from a prior application (37 CFR 1.63(d))
7. [✔] **Application Data Sheet** ** See note below.* See 37 CFR 1.76 (PTO/AIA/14 or equivalent)
8. **CD-ROM or CD-R** in duplicate, large table, or Computer Program (*Appendix*)
   [ ] Landscape Table on CD
9. **Nucleotide and/or Amino Acid Sequence Submission** (*if applicable, items a. – c. are required*)
   a. [ ] Computer Readable Form (CRF)
   b. [ ] Specification Sequence Listing on:
      i. [ ] CD-ROM or CD-R (2 copies); or
      ii. [ ] Paper
   c. [ ] Statements verifying identity of above copies

ADDRESS TO:

Commissioner for Patents
P.O. Box 1450
Alexandria, VA 22313-1450

ACCOMPANYING APPLICATION PAPERS

10. [ ] **Assignment Papers** (cover sheet & document(s))
    Name of Assignee
11. [ ] **37 CFR 3.73(c) Statement** (*when there is an assignee*) [ ] **Power of Attorney**
12. [ ] **English Translation Document** (*if applicable*)
13. [ ] **Information Disclosure Statement** (PTO/SB/08 or PTO-1449)
    [ ] Copies of citations attached
14. [ ] **Preliminary Amendment**
15. [ ] **Return Receipt Postcard** (*MPEP § 503*) (*Should be specifically itemized*)
16. [ ] **Certified Copy of Priority Document(s)** (*if foreign priority is claimed*)
17. [ ] **Nonpublication Request** Under 35 U.S.C. 122(b)(2)(B)(i). Applicant must attach form PTO/SB/35 or equivalent.
18. [✔] **Other:** Request for Prioritized Examination

Note*: (1) Benefit claims under 37 CFR 1.78 and foreign priority claims under 1.55 **must be included in an Application Data Sheet (ADS).
(2) For applications filed under 35 U.S.C. 111, the application must contain an ADS specifying the applicant if the applicant is an assignee, person to whom the inventor is under an obligation to assign, or person who otherwise shows sufficient proprietary interest in the matter. See 37 CFR 1.46(b).

19. CORRESPONDENCE ADDRESS

[✔] The address associated with Customer Number: 132858 **OR** [ ] Correspondence address below

Name					
Address					
City		State		Zip Code	
Country		Telephone		Email	

Signature	/Taylor P. Evans/	Date	2019-10-09
Name (Print/Type)	Taylor P. Evans	Registration No. (Attorney/Agent)	60506

This collection of information is required by 37 CFR 1.53(b). The information is required to obtain or retain a benefit by the public which is to file (and by the USPTO to process) an application. Confidentiality is governed by 35 U.S.C. 122 and 37 CFR 1.11 and 1.14. This collection is estimated to take 12 minutes to complete, including gathering, preparing, and submitting the completed application form to the USPTO. Time will vary depending upon the individual case. Any comments on the amount of time you require to complete this form and/or suggestions for reducing this burden, should be sent to the Chief Information Officer, U.S. Patent and Trademark Office, U.S. Department of Commerce, P.O. Box 1450, Alexandria, VA 22313-1450. DO NOT SEND FEES OR COMPLETED FORMS TO THIS ADDRESS. **SEND TO: Commissioner for Patents, P.O. Box 1450, Alexandria, VA 22313-1450.**

If you need assistance in completing the form, call 1-800-PTO-9199 and select option 2.

Privacy Act Statement

The **Privacy Act of 1974 (P.L. 93-579)** requires that you be given certain information in connection with your submission of the attached form related to a patent application or patent. Accordingly, pursuant to the requirements of the Act, please be advised that: (1) the general authority for the collection of this information is 35 U.S.C. 2(b)(2); (2) furnishing of the information solicited is voluntary; and (3) the principal purpose for which the information is used by the U.S. Patent and Trademark Office is to process and/or examine your submission related to a patent application or patent. If you do not furnish the requested information, the U.S. Patent and Trademark Office may not be able to process and/or examine your submission, which may result in termination of proceedings or abandonment of the application or expiration of the patent.

The information provided by you in this form will be subject to the following routine uses:

1. The information on this form will be treated confidentially to the extent allowed under the Freedom of Information Act (5 U.S.C. 552) and the Privacy Act (5 U.S.C 552a). Records from this system of records may be disclosed to the Department of Justice to determine whether disclosure of these records is required by the Freedom of Information Act.
2. A record from this system of records may be disclosed, as a routine use, in the course of presenting evidence to a court, magistrate, or administrative tribunal, including disclosures to opposing counsel in the course of settlement negotiations.
3. A record in this system of records may be disclosed, as a routine use, to a Member of Congress submitting a request involving an individual, to whom the record pertains, when the individual has requested assistance from the Member with respect to the subject matter of the record.
4. A record in this system of records may be disclosed, as a routine use, to a contractor of the Agency having need for the information in order to perform a contract. Recipients of information shall be required to comply with the requirements of the Privacy Act of 1974, as amended, pursuant to 5 U.S.C. 552a(m).
5. A record related to an International Application filed under the Patent Cooperation Treaty in this system of records may be disclosed, as a routine use, to the International Bureau of the World Intellectual Property Organization, pursuant to the Patent Cooperation Treaty.
6. A record in this system of records may be disclosed, as a routine use, to another federal agency for purposes of National Security review (35 U.S.C. 181) and for review pursuant to the Atomic Energy Act (42 U.S.C. 218(c)).
7. A record from this system of records may be disclosed, as a routine use, to the Administrator, General Services, or his/her designee, during an inspection of records conducted by GSA as part of that agency's responsibility to recommend improvements in records management practices and programs, under authority of 44 U.S.C. 2904 and 2906. Such disclosure shall be made in accordance with the GSA regulations governing inspection of records for this purpose, and any other relevant (*i.e.*, GSA or Commerce) directive. Such disclosure shall not be used to make determinations about individuals.
8. A record from this system of records may be disclosed, as a routine use, to the public after either publication of the application pursuant to 35 U.S.C. 122(b) or issuance of a patent pursuant to 35 U.S.C. 151. Further, a record may be disclosed, subject to the limitations of 37 CFR 1.14, as a routine use, to the public if the record was filed in an application which became abandoned or in which the proceedings were terminated and which application is referenced by either a published application, an application open to public inspection or an issued patent.
9. A record from this system of records may be disclosed, as a routine use, to a Federal, State, or local law enforcement agency, if the USPTO becomes aware of a violation or potential violation of law or regulation.

Electronic Patent Application Fee Transmittal

Application Number:	
Filing Date:	
Title of Invention:	MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT
First Named Inventor/Applicant Name:	Jared Oehring
Filer:	Taylor P. Evans/Stephanie McDonough
Attorney Docket Number:	047158.100048

Filed as Large Entity

Filing Fees for Track I Prioritized Examination - Nonprovisional Application under 35 USC 111(a)

Description	Fee Code	Quantity	Amount	Sub-Total in USD($)
Basic Filing:				
UTILITY APPLICATION FILING	1011	1	300	300
UTILITY SEARCH FEE	1111	1	660	660
UTILITY EXAMINATION FEE	1311	1	760	760
REQUEST FOR PRIORITIZED EXAMINATION	1817	1	4000	4000
Pages:				
Claims:				
Miscellaneous-Filing:				

Description	Fee Code	Quantity	Amount	Sub-Total in USD($)
PUBL. FEE- EARLY, VOLUNTARY, OR NORMAL	1504	1	0	0
PROCESSING FEE, EXCEPT PROV. APPLS.	1830	1	140	140

Petition:	
Patent-Appeals-and-Interference:	
Post-Allowance-and-Post-Issuance:	
Extension-of-Time:	
Miscellaneous:	
Total in USD ($)	**5860**

Electronic Acknowledgement Receipt

EFS ID:	37405426
Application Number:	16597014
International Application Number:	
Confirmation Number:	4687
Title of Invention:	MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT
First Named Inventor/Applicant Name:	Jared Oehring
Customer Number:	132858
Filer:	Taylor P. Evans/Stephanie McDonough
Filer Authorized By:	Taylor P. Evans
Attorney Docket Number:	047158.100048
Receipt Date:	09-OCT-2019
Filing Date:	
Time Stamp:	12:29:17
Application Type:	Utility under 35 USC 111(a)

Payment information:

Submitted with Payment	yes
Payment Type	DA
Payment was successfully received in RAM	$5860
RAM confirmation Number	E201909C29595478
Deposit Account	501349
Authorized User	Stephanie McDonough

The Director of the USPTO is hereby authorized to charge indicated fees and credit any overpayment as follows:

37 CFR 1.16 (National application filing, search, and examination fees)

37 CFR 1.17 (Patent application and reexamination processing fees)

37 CFR 1.19 (Document supply fees)

37 CFR 1.20 (Post Issuance fees)

37 CFR 1.21 (Miscellaneous fees and charges)

File Listing:

Document Number	Document Description	File Name	File Size(Bytes)/ Message Digest	Multi Part /.zip	Pages (if appl.)
1	Application Data Sheet	WebADS.pdf	139291 7f30f54e81bbe8568014846ed7928772f643037d	no	8
Warnings:					
Information:					
2	Drawings-only black and white line drawings	047158-100048_Figures.pdf	310627 33f93f3cebb08ec2bd910bd5174961e284131ef8	no	15
Warnings:					
The page size in the PDF is too large. The pages should be 8.5 x 11 or A4. If this PDF is submitted, the pages will be resized upon entry into the Image File Wrapper and may affect subsequent processing					
Information:					
3		047158-100048_Specification.pdf	170036 f3de4c2c64e8e957c4c7f54f86aa44de9618027b	yes	36

Multipart Description/PDF files in .zip description

Document Description	Start	End
Specification	1	31
Claims	32	35
Abstract	36	36

Warnings:					
Information:					
4	TrackOne Request	047158-100048_Track_one.pdf	124675 9d356e75b7c94cf6dc9fe5083305ceb998f4e795	no	2
Warnings:					
Information:					

5	Transmittal of New Application	047158-100048_Utility_tml.pdf	287839 cfa4f33558e2949176516cdaee8020fcdba14300	no	2
Warnings:					
Information:					
6	Fee Worksheet (SB06)	fee-info.pdf	40321 71450087f722f53c2b343ceb10a700f3f60a7cdb	no	2
Warnings:					
Information:					
		Total Files Size (in bytes):	1072789		

This Acknowledgement Receipt evidences receipt on the noted date by the USPTO of the indicated documents, characterized by the applicant, and including page counts, where applicable. It serves as evidence of receipt similar to a Post Card, as described in MPEP 503.

New Applications Under 35 U.S.C. 111

If a new application is being filed and the application includes the necessary components for a filing date (see 37 CFR 1.53(b)-(d) and MPEP 506), a Filing Receipt (37 CFR 1.54) will be issued in due course and the date shown on this Acknowledgement Receipt will establish the filing date of the application.

National Stage of an International Application under 35 U.S.C. 371

If a timely submission to enter the national stage of an international application is compliant with the conditions of 35 U.S.C. 371 and other applicable requirements a Form PCT/DO/EO/903 indicating acceptance of the application as a national stage submission under 35 U.S.C. 371 will be issued in addition to the Filing Receipt, in due course.

New International Application Filed with the USPTO as a Receiving Office

If a new international application is being filed and the international application includes the necessary components for an international filing date (see PCT Article 11 and MPEP 1810), a Notification of the International Application Number and of the International Filing Date (Form PCT/RO/105) will be issued in due course, subject to prescriptions concerning national security, and the date shown on this Acknowledgement Receipt will establish the international filing date of the application.

Application Data Sheet 37 CFR 1.76	Attorney Docket Number	047158.100048
	Application Number	
Title of Invention	MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT	

The application data sheet is part of the provisional or nonprovisional application for which it is being submitted. The following form contains the bibliographic data arranged in a format specified by the United States Patent and Trademark Office as outlined in 37 CFR 1.76.
This document may be completed electronically and submitted to the Office in electronic format using the Electronic Filing System (EFS) or the document may be printed and included in a paper filed application.

Secrecy Order 37 CFR 5.2:

☐ Portions or all of the application associated with this Application Data Sheet may fall under a Secrecy Order pursuant to 37 CFR 5.2 (Paper filers only. Applications that fall under Secrecy Order may not be filed electronically.)

Inventor Information:

Inventor 1

Legal Name

Prefix	Given Name	Middle Name	Family Name	Suffix
	Jared		Oehring	

Residence Information (Select One) ◉ US Residency ○ Non US Residency ○ Active US Military Service

City	Houston	State/Province	TX	Country of Residence i	US

Mailing Address of Inventor:

Address 1	c/o U.S. Well Services, LLC		
Address 2	1360 Post Oak Boulevard, Suite 1800		
City	Houston	State/Province	TX
Postal Code	77056	Country i	US

Inventor 2

Legal Name

Prefix	Given Name	Middle Name	Family Name	Suffix
	Brandon	N.	Hinderliter	

Residence Information (Select One) ◉ US Residency ○ Non US Residency ○ Active US Military Service

City	Houston	State/Province	TX	Country of Residence i	US

Mailing Address of Inventor:

Address 1	c/o U.S. Well Services, LLC		
Address 2	1360 Post Oak Boulevard, Suite 1800		
City	Houston	State/Province	TX
Postal Code	77056	Country i	US

Inventor 3

Legal Name

Prefix	Given Name	Middle Name	Family Name	Suffix
	Lon		Robinson	

PTO/AIA/14 (08-15)
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U.S. Patent and Trademark Office; U.S. DEPARTMENT OF COMMERCE
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Application Data Sheet 37 CFR 1.76	Attorney Docket Number	047158.100048
	Application Number	
Title of Invention	MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT	

Residence Information (Select One)	◉ US Residency	○ Non US Residency	○ Active US Military Service

City	Houston	**State/Province**	TX	**Country of Residence** i	US

Mailing Address of Inventor:

Address 1	c/o U.S. Well Services, LLC		
Address 2	1360 Post Oak Boulevard, Suite 1800		
City	Houston	**State/Province**	TX
Postal Code	77056	**Country** i	US

All Inventors Must Be Listed - Additional Inventor Information blocks may be generated within this form by selecting the **Add** button. Add

Correspondence Information:

Enter either Customer Number or complete the Correspondence Information section below.
For further information see 37 CFR 1.33(a).

☐ **An Address is being provided for the correspondence Information of this application.**

Customer Number	132858		
Email Address	hlusdocketing@hoganlovells.com	Add Email	Remove Email

Application Information:

Title of the Invention	MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT		
Attorney Docket Number	047158.100048	**Small Entity Status Claimed**	☐
Application Type	Nonprovisional		
Subject Matter	Utility		
Total Number of Drawing Sheets (if any)	15	**Suggested Figure for Publication (if any)**	

Filing By Reference:

Only complete this section when filing an application by reference under 35 U.S.C. 111(c) and 37 CFR 1.57(a). Do not complete this section if application papers including a specification and any drawings are being filed. Any domestic benefit or foreign priority information must be provided in the appropriate section(s) below (i.e., "Domestic Benefit/National Stage Information" and "Foreign Priority Information").

For the purposes of a filing date under 37 CFR 1.53(b), the description and any drawings of the present application are replaced by this reference to the previously filed application, subject to conditions and requirements of 37 CFR 1.57(a).

Application number of the previously filed application	Filing date (YYYY-MM-DD)	Intellectual Property Authority or Country i

PTO/AIA/14 (08-15)
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U.S. Patent and Trademark Office; U.S. DEPARTMENT OF COMMERCE
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Application Data Sheet 37 CFR 1.76	Attorney Docket Number	047158.100048
	Application Number	
Title of Invention	MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT	

Publication Information:

☐ Request Early Publication (Fee required at time of Request 37 CFR 1.219)

☐ **Request Not to Publish.** I hereby request that the attached application not be published under 35 U.S.C. 122(b) and certify that the invention disclosed in the attached application **has not and will not** be the subject of an application filed in another country, or under a multilateral international agreement, that requires publication at eighteen months after filing.

Representative Information:

Representative information should be provided for all practitioners having a power of attorney in the application. Providing this information in the Application Data Sheet does not constitute a power of attorney in the application (see 37 CFR 1.32).
Either enter Customer Number or complete the Representative Name section below. If both sections are completed the customer Number will be used for the Representative Information during processing.

Please Select One:	◉ Customer Number	○ US Patent Practitioner	○ Limited Recognition (37 CFR 11.9)
Customer Number	132858		

Prefix	**Given Name**	Middle Name	**Family Name**	Suffix	Remove
Registration Number					
Prefix	**Given Name**	Middle Name	**Family Name**	Suffix	Remove
Registration Number					

Additional Representative Information blocks may be generated within this form by selecting the **Add** button.

Domestic Benefit/National Stage Information:

This section allows for the applicant to either claim benefit under 35 U.S.C. 119(e), 120, 121, 365(c), or 386(c) or indicate National Stage entry from a PCT application. Providing benefit claim information in the Application Data Sheet constitutes the specific reference required by 35 U.S.C. 119(e) or 120, and 37 CFR 1.78.
When referring to the current application, please leave the "Application Number" field blank.

Prior Application Status	Pending		Remove
Application Number	Continuity Type	Prior Application Number	Filing or 371(c) Date (YYYY-MM-DD)
	Claims benefit of provisional	62743299	2018-10-09

PTO/AIA/14 (08-15)
Approved for use through 04/30/2017. OMB 0651-0032
U.S. Patent and Trademark Office; U.S. DEPARTMENT OF COMMERCE
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Application Data Sheet 37 CFR 1.76	Attorney Docket Number	047158.100048
	Application Number	
Title of Invention	MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT	

Prior Application Status	Pending	Remove

Application Number	Continuity Type	Prior Application Number	Filing or 371(c) Date (YYYY-MM-DD)
	Claims benefit of provisional	62743360	2018-10-09

Additional Domestic Benefit/National Stage Data may be generated within this form by selecting the **Add** button.

Foreign Priority Information:

This section allows for the applicant to claim priority to a foreign application. Providing this information in the application data sheet constitutes the claim for priority as required by 35 U.S.C. 119(b) and 37 CFR 1.55. When priority is claimed to a foreign application that is eligible for retrieval under the priority document exchange program (PDX) the information will be used by the Office to automatically attempt retrieval pursuant to 37 CFR 1.55(i)(1) and (2). Under the PDX program, applicant bears the ultimate responsibility for ensuring that a copy of the foreign application is received by the Office from the participating foreign intellectual property office, or a certified copy of the foreign priority application is filed, within the time period specified in 37 CFR 1.55(g)(1).

Application Number	Country	Filing Date (YYYY-MM-DD)	Access Code (if applicable)

Additional Foreign Priority Data may be generated within this form by selecting the **Add** button.

Statement under 37 CFR 1.55 or 1.78 for AIA (First Inventor to File) Transition Applications

☐ This application (1) claims priority to or the benefit of an application filed before March 16, 2013 and (2) also contains, or contained at any time, a claim to a claimed invention that has an effective filing date on or after March 16, 2013.
NOTE: By providing this statement under 37 CFR 1.55 or 1.78, this application, with a filing date on or after March 16, 2013, will be examined under the first inventor to file provisions of the AIA.

PTO/AIA/14 (08-15)
Approved for use through 04/30/2017. OMB 0651-0032
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Application Data Sheet 37 CFR 1.76	Attorney Docket Number	047158.100048
	Application Number	
Title of Invention	MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT	

Authorization or Opt-Out of Authorization to Permit Access:

When this Application Data Sheet is properly signed and filed with the application, applicant has provided written authority to permit a participating foreign intellectual property (IP) office access to the instant application-as-filed (see paragraph A in subsection 1 below) and the European Patent Office (EPO) access to any search results from the instant application (see paragraph B in subsection 1 below).

Should applicant choose not to provide an authorization identified in subsection 1 below, applicant **must opt-out** of the authorization by checking the corresponding box A or B or both in subsection 2 below.

NOTE: This section of the Application Data Sheet is **ONLY** reviewed and processed with the **INITIAL** filing of an application. After the initial filing of an application, an Application Data Sheet cannot be used to provide or rescind authorization for access by a foreign IP office(s). Instead, Form PTO/SB/39 or PTO/SB/69 must be used as appropriate.

1. Authorization to Permit Access by a Foreign Intellectual Property Office(s)

A. Priority Document Exchange (PDX) - Unless box A in subsection 2 (opt-out of authorization) is checked, the undersigned hereby **grants the USPTO authority** to provide the European Patent Office (EPO), the Japan Patent Office (JPO), the Korean Intellectual Property Office (KIPO), the State Intellectual Property Office of the People's Republic of China (SIPO), the World Intellectual Property Organization (WIPO), and any other foreign intellectual property office participating with the USPTO in a bilateral or multilateral priority document exchange agreement in which a foreign application claiming priority to the instant patent application is filed, access to: (1) the instant patent application-as-filed and its related bibliographic data, (2) any foreign or domestic application to which priority or benefit is claimed by the instant application and its related bibliographic data, and (3) the date of filing of this Authorization. See 37 CFR 1.14(h)(1).

B. Search Results from U.S. Application to EPO - Unless box B in subsection 2 (opt-out of authorization) is checked, the undersigned hereby **grants the USPTO authority** to provide the EPO access to the bibliographic data and search results from the instant patent application when a European patent application claiming priority to the instant patent application is filed. See 37 CFR 1.14(h)(2).

The applicant is reminded that the EPO's Rule 141(1) EPC (European Patent Convention) requires applicants to submit a copy of search results from the instant application without delay in a European patent application that claims priority to the instant application.

2. Opt-Out of Authorizations to Permit Access by a Foreign Intellectual Property Office(s)

☐ A. Applicant **DOES NOT** authorize the USPTO to permit a participating foreign IP office access to the instant application-as-filed. If this box is checked, the USPTO will not be providing a participating foreign IP office with any documents and information identified in subsection 1A above.

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Applicant Information:

Providing assignment information in this section does not substitute for compliance with any requirement of part 3 of Title 37 of CFR to have an assignment recorded by the Office.

Applicant 1

If the applicant is the inventor (or the remaining joint inventor or inventors under 37 CFR 1.45), this section should not be completed. The information to be provided in this section is the name and address of the legal representative who is the applicant under 37 CFR 1.43; or the name and address of the assignee, person to whom the inventor is under an obligation to assign the invention, or person who otherwise shows sufficient proprietary interest in the matter who is the applicant under 37 CFR 1.46. If the applicant is an applicant under 37 CFR 1.46 (assignee, person to whom the inventor is obligated to assign, or person who otherwise shows sufficient proprietary interest) together with one or more joint inventors, then the joint inventor or inventors who are also the applicant should be identified in this section.

Clear

◉ Assignee	○ Legal Representative under 35 U.S.C. 117	○ Joint Inventor
○ Person to whom the inventor is obligated to assign.	○ Person who shows sufficient proprietary interest	

If applicant is the legal representative, indicate the authority to file the patent application, the inventor is:

Name of the Deceased or Legally Incapacitated Inventor:	

If the Applicant is an Organization check here. ☒

Organization Name	U.S. Well Services, LLC

Mailing Address Information For Applicant:

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Address 2			
City	Houston	**State/Province**	TX
Country[i]	US	Postal Code	77056
Phone Number		Fax Number	
Email Address			

Additional Applicant Data may be generated within this form by selecting the Add button.

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Assignee Information including Non-Applicant Assignee Information:

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Assignee 1

Complete this section if assignee information, including non-applicant assignee information, is desired to be included on the patent application publication. An assignee-applicant identified in the "Applicant Information" section will appear on the patent application publication as an applicant. For an assignee-applicant, complete this section only if identification as an assignee is also desired on the patent application publication.

If the Assignee or Non-Applicant Assignee is an Organization check here. ☒

Organization Name	U.S. Well Services, LLC

Mailing Address Information For Assignee including Non-Applicant Assignee:

Address 1	1360 Post Oak Boulevard, Suite 1800		
Address 2			
City	Houston	**State/Province**	TX
Country i	US	Postal Code	77056
Phone Number		Fax Number	
Email Address			

Additional Assignee or Non-Applicant Assignee Data may be generated within this form by selecting the Add button.

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	Application Number	
Title of Invention	MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT	

Signature:

NOTE: This Application Data Sheet must be signed in accordance with 37 CFR 1.33(b). **However, if this Application Data Sheet is submitted with the INITIAL filing of the application and either box A or B is not checked in subsection 2 of the "Authorization or Opt-Out of Authorization to Permit Access" section, then this form must also be signed in accordance with 37 CFR 1.14(c).**

This Application Data Sheet **must** be signed by a patent practitioner if one or more of the applicants is a **juristic entity** (e. g., corporation or association). If the applicant is two or more joint inventors, this form must be signed by a patent practitioner, **all** joint inventors who are the applicant, or one or more joint inventor-applicants who have been given power of attorney (e.g., see USPTO Form PTO/AIA/81) on behalf of **all** joint inventor-applicants.

See 37 CFR 1.4(d) for the manner of making signatures and certifications.

Signature	/Taylor P. Evans/			Date (YYYY-MM-DD)	
First Name	Taylor P.	Last Name	Evans	Registration Number	60506

Additional Signature may be generated within this form by selecting the Add button.

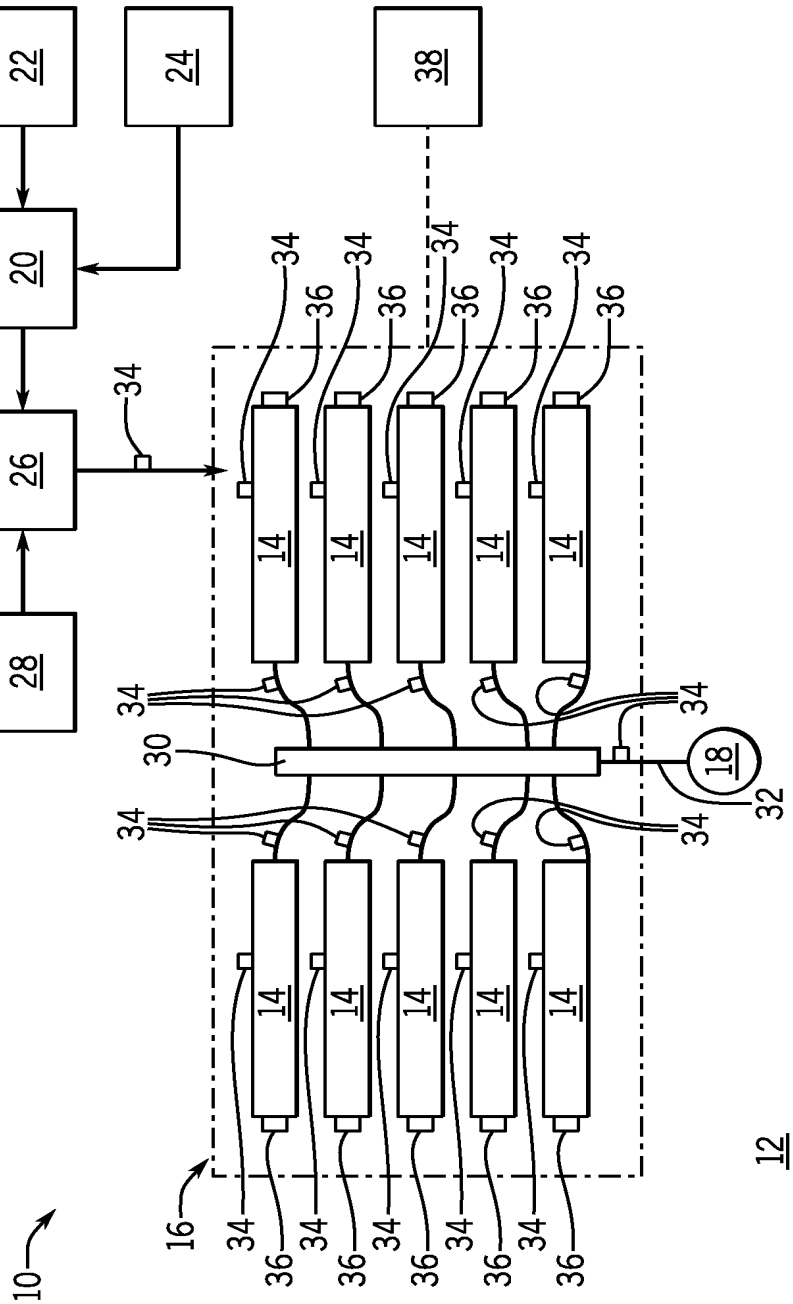


FIG. 1

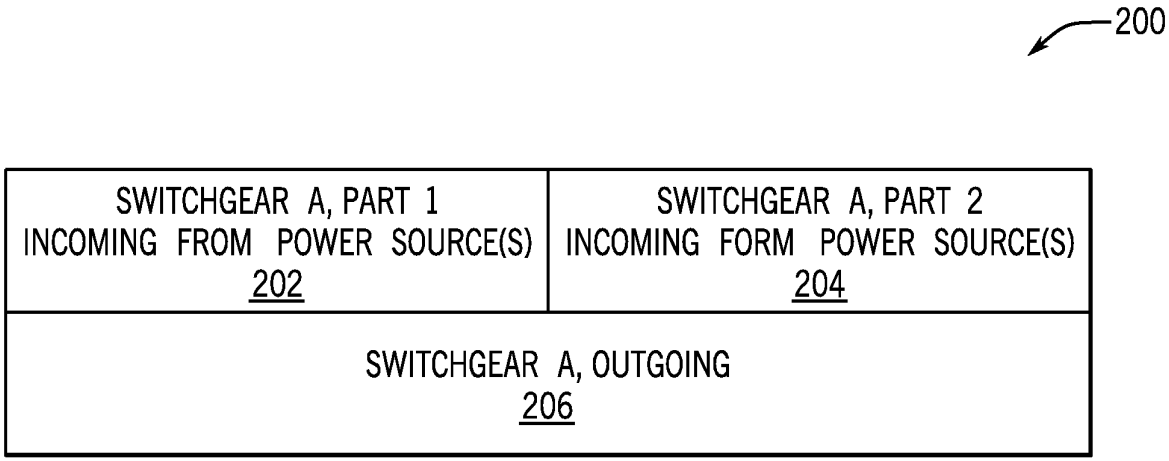

200
SWITCHGEAR A, PART 1
INCOMING FROM POWER SOURCE(S)
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SWITCHGEAR A, PART 2
INCOMING FORM POWER SOURCE(S)
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SWITCHGEAR A, OUTGOING
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FIG. 2

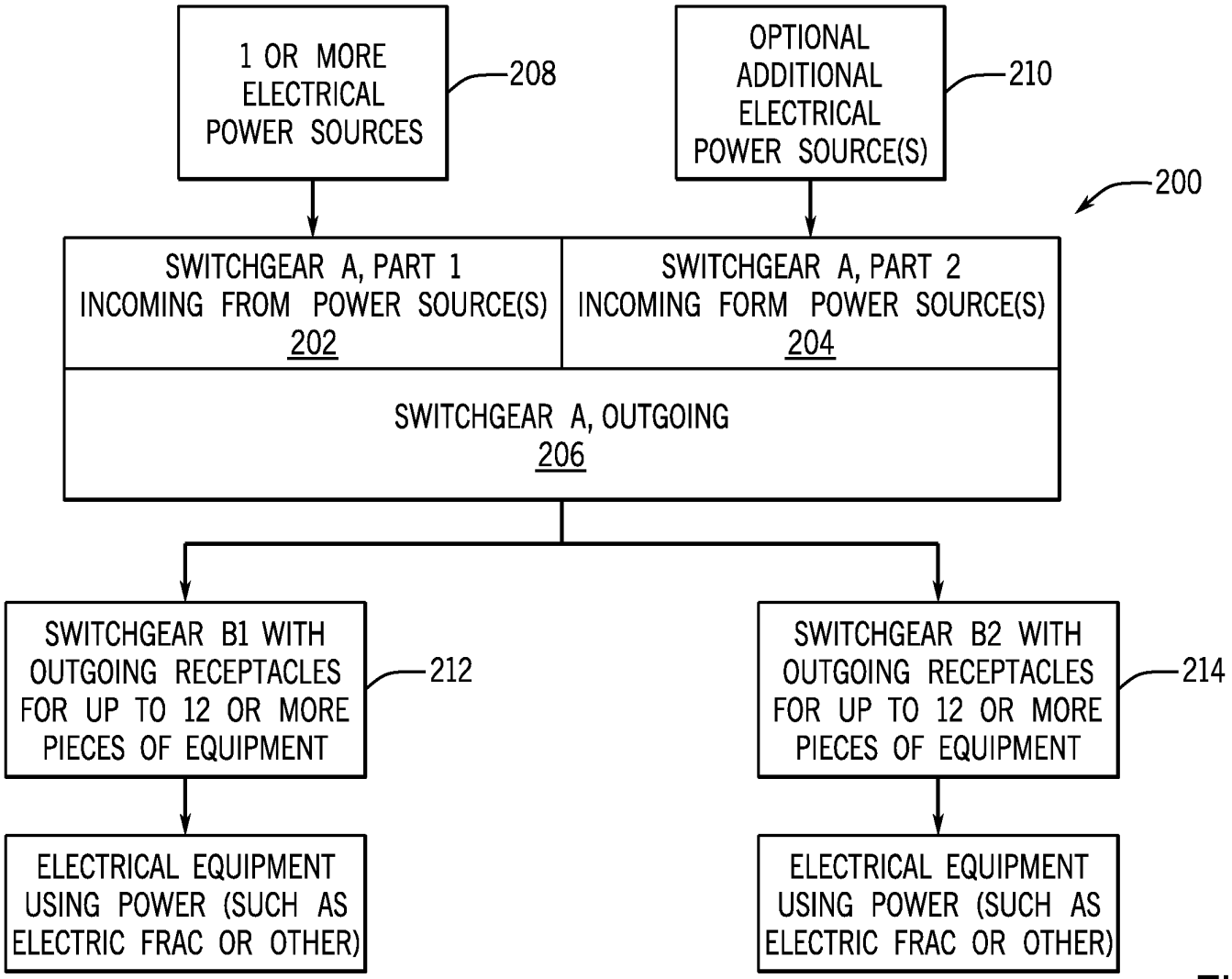

1 OR MORE ELECTRICAL POWER SOURCES
208
OPTIONAL ADDITIONAL ELECTRICAL POWER SOURCE(S)
210
200
SWITCHGEAR A, PART 1 INCOMING FROM POWER SOURCE(S) 202
SWITCHGEAR A, PART 2 INCOMING FORM POWER SOURCE(S) 204
SWITCHGEAR A, OUTGOING 206
SWITCHGEAR B1 WITH OUTGOING RECEPTACLES FOR UP TO 12 OR MORE PIECES OF EQUIPMENT
212
SWITCHGEAR B2 WITH OUTGOING RECEPTACLES FOR UP TO 12 OR MORE PIECES OF EQUIPMENT
214
ELECTRICAL EQUIPMENT USING POWER (SUCH AS ELECTRIC FRAC OR OTHER)
ELECTRICAL EQUIPMENT USING POWER (SUCH AS ELECTRIC FRAC OR OTHER)

FIG. 3

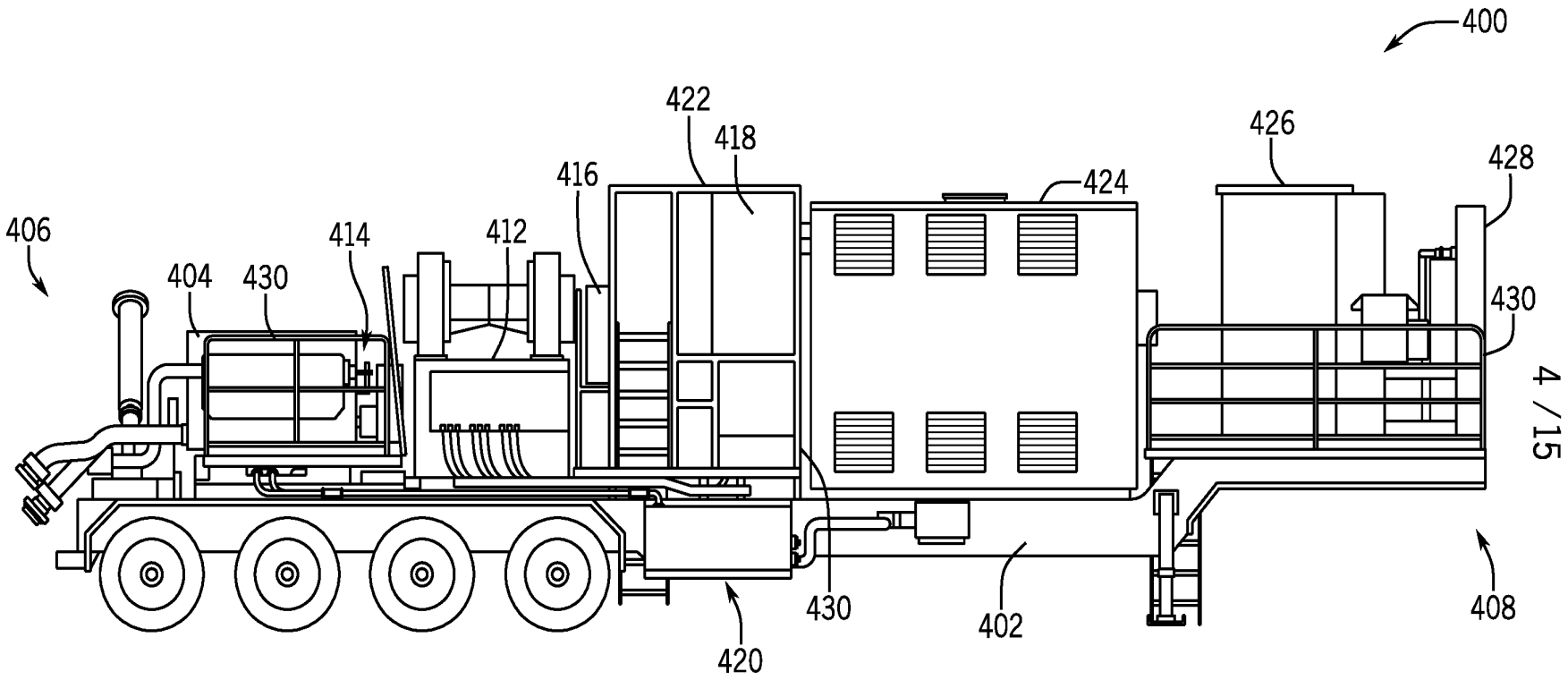

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FIG. 4

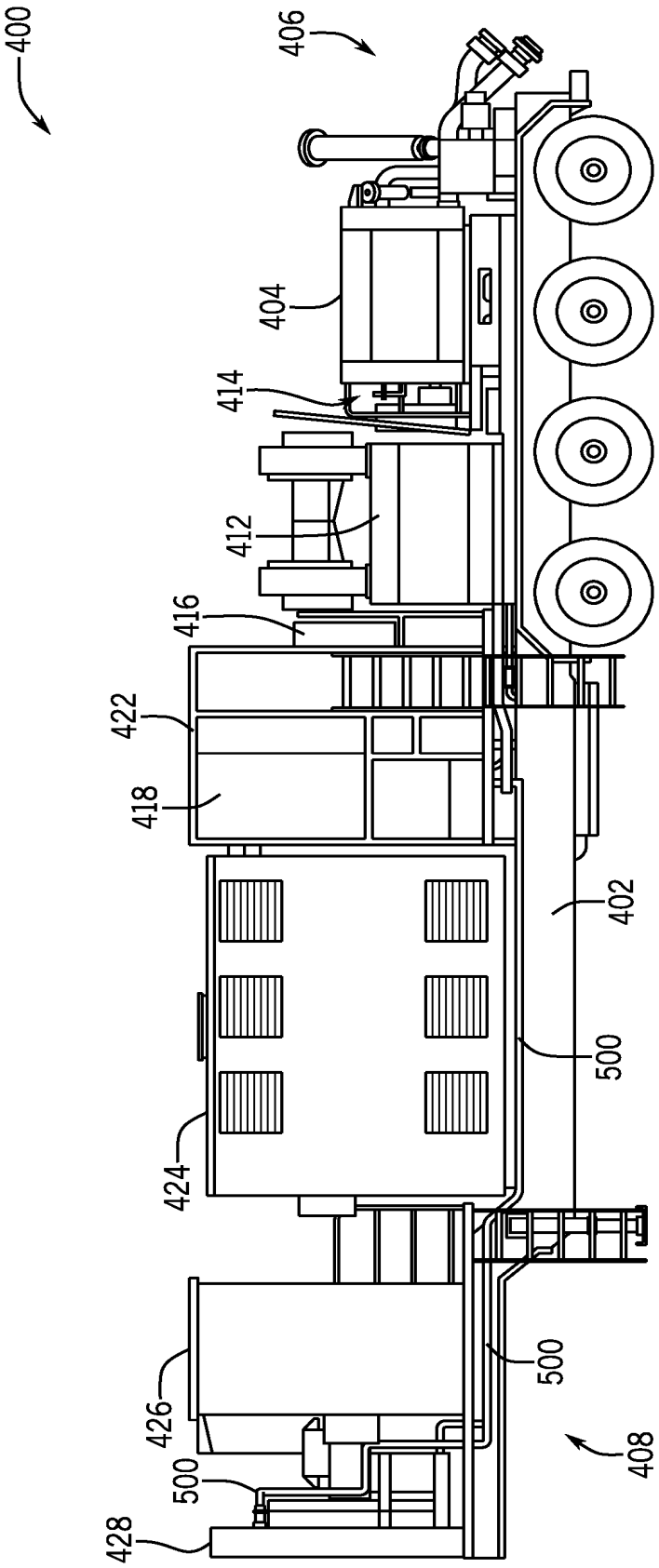


FIG. 5

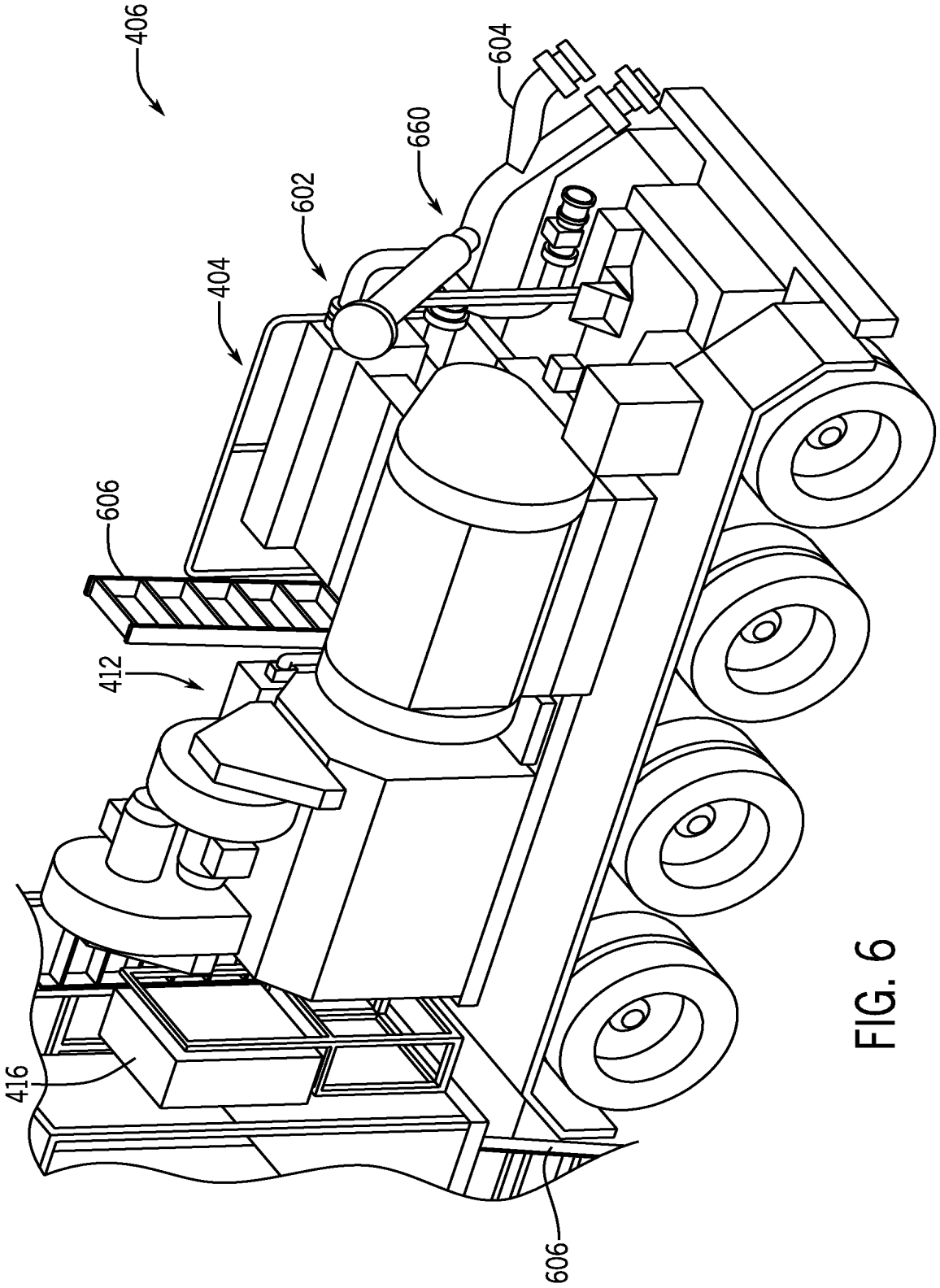


FIG. 6

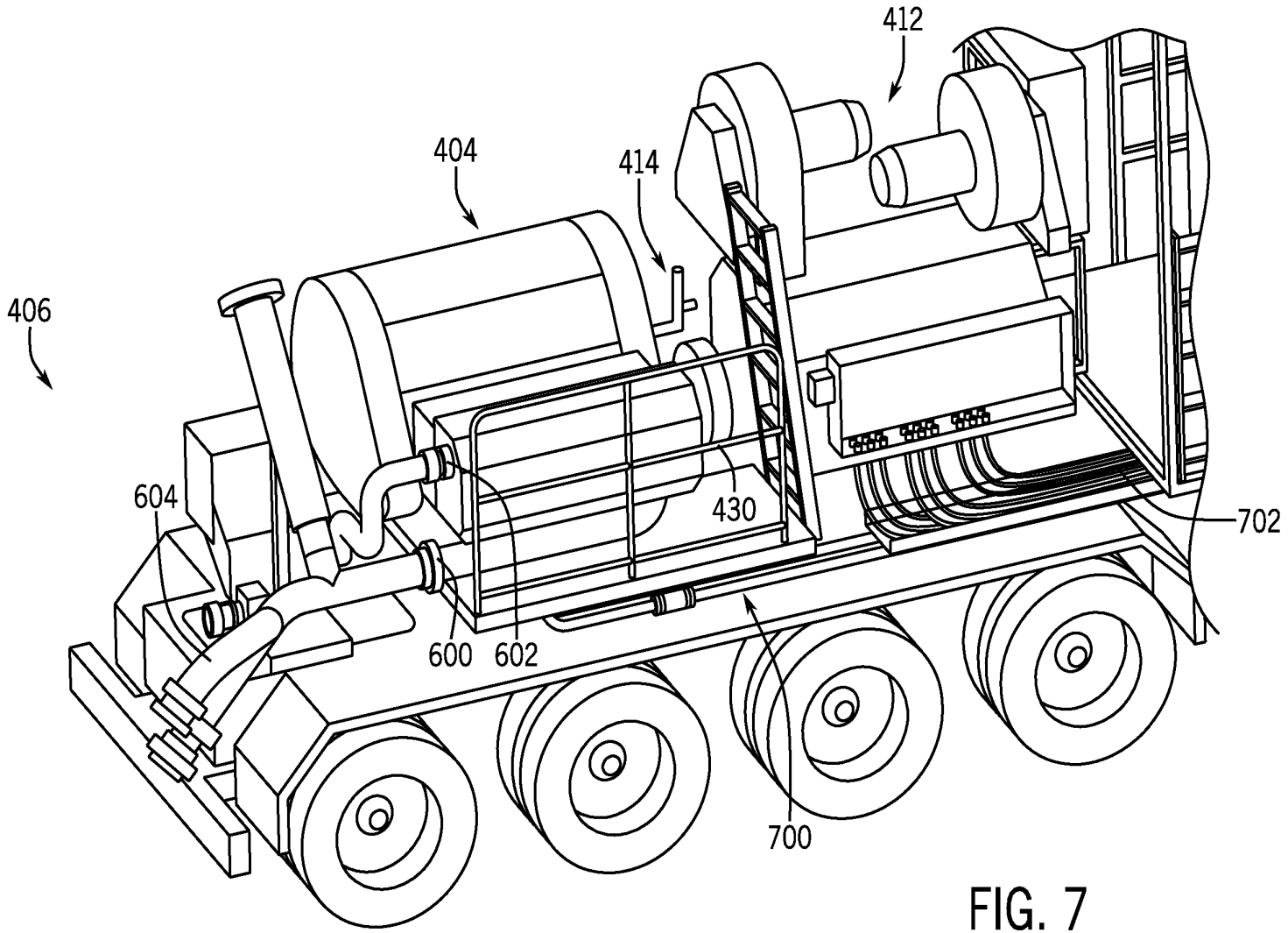


FIG. 7

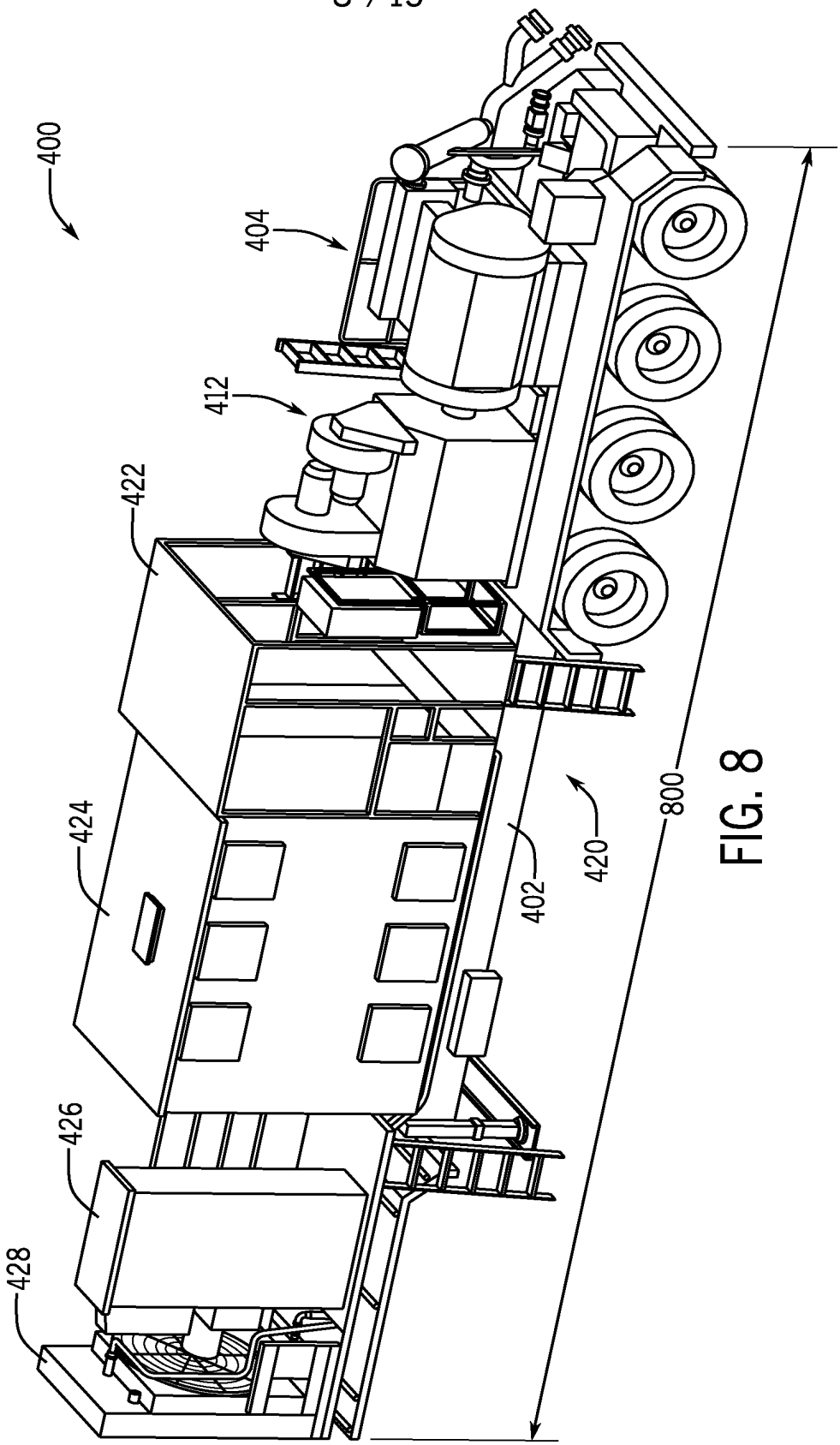


FIG. 8

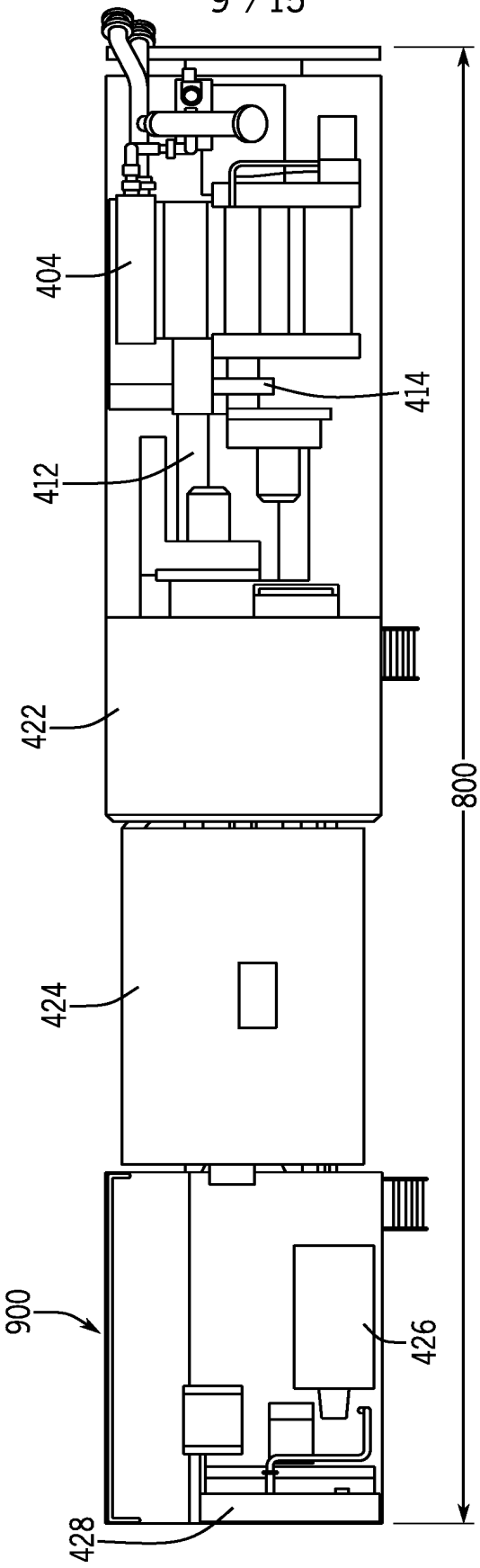


FIG. 9

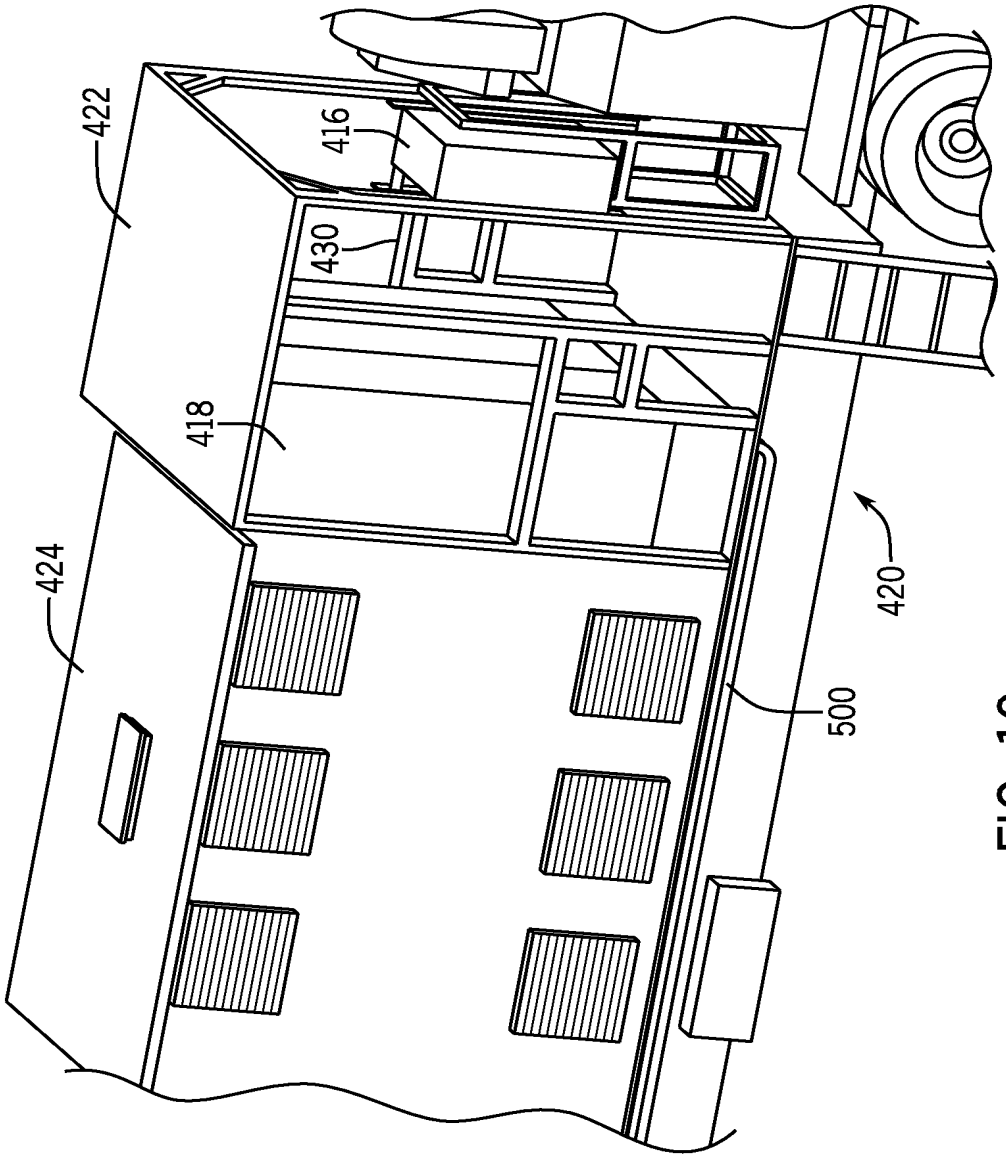


FIG. 10

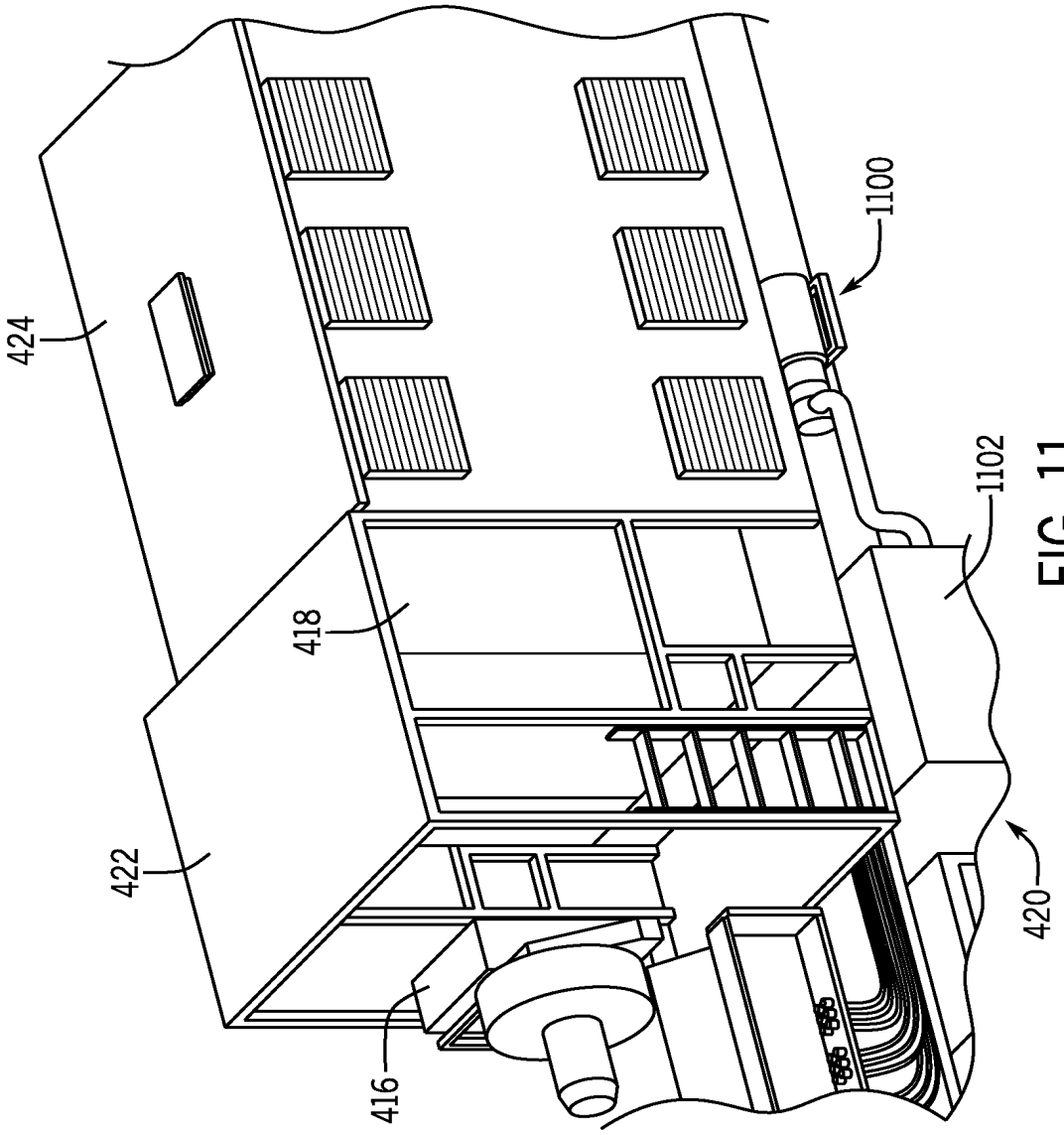


FIG. 11

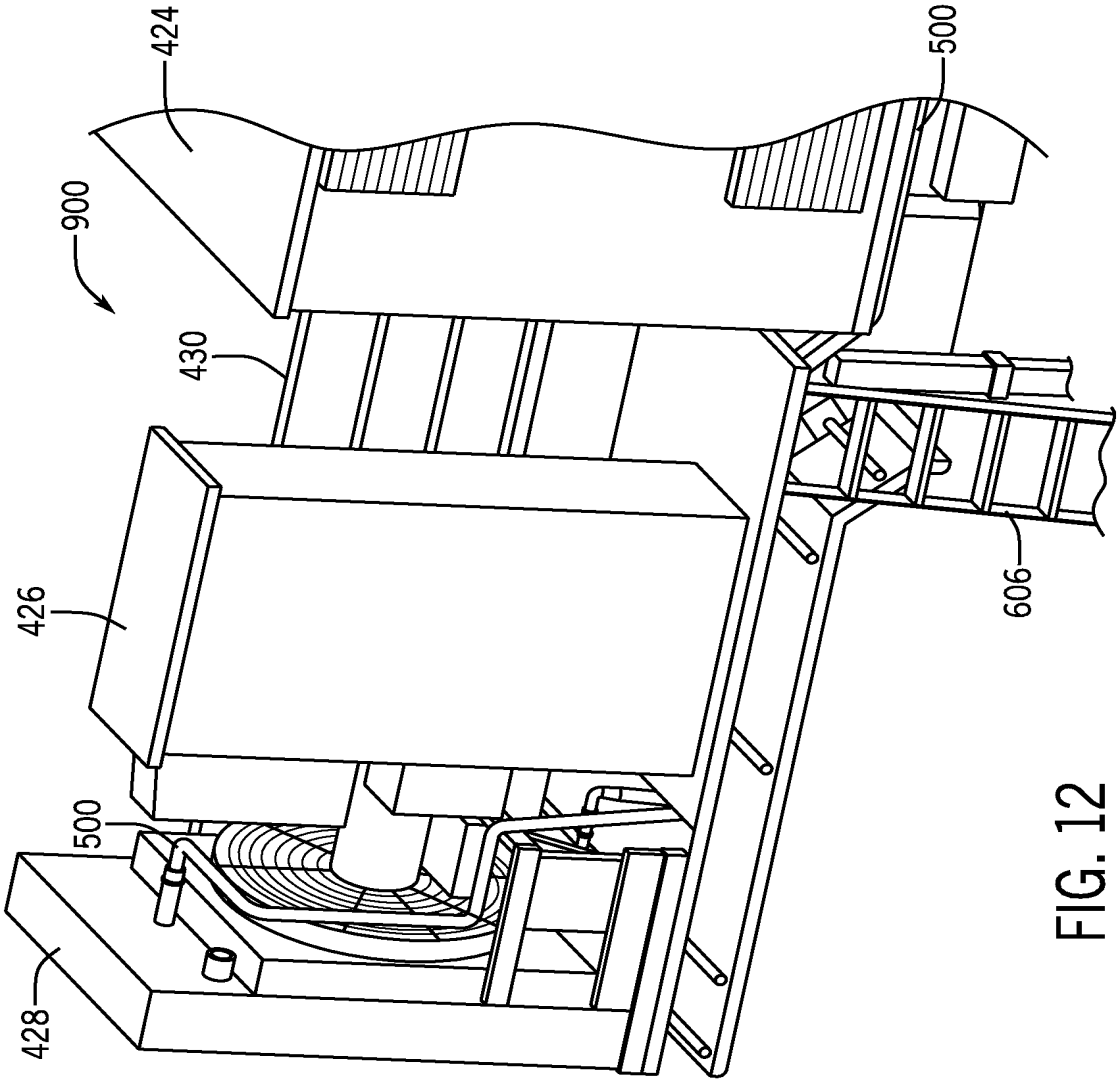


FIG. 12

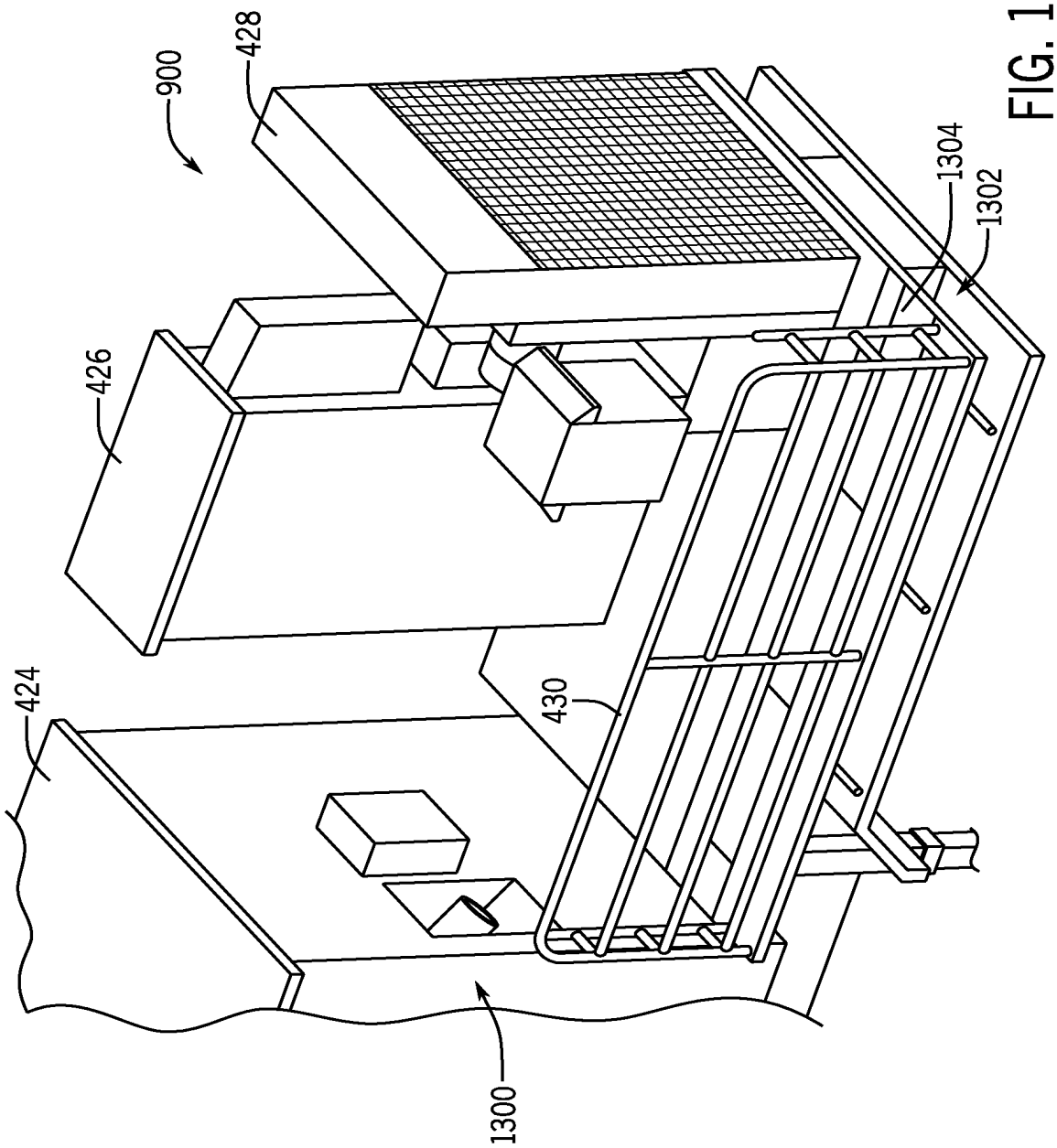


FIG. 13

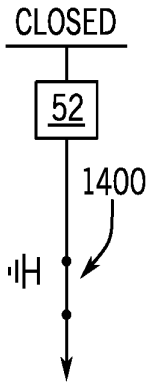


FIG. 14A

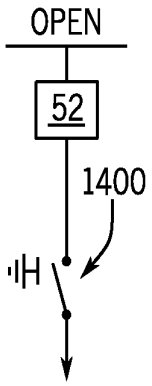


FIG. 14B

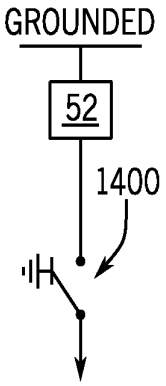


FIG. 14C

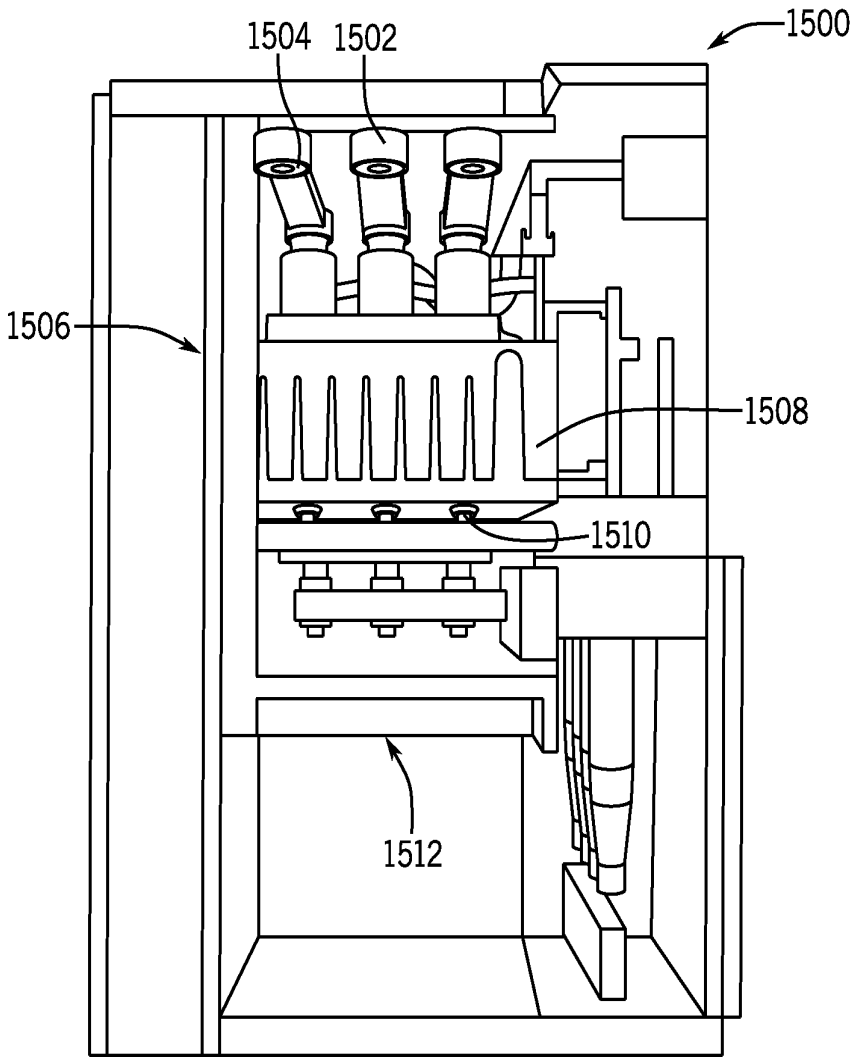


FIG. 15

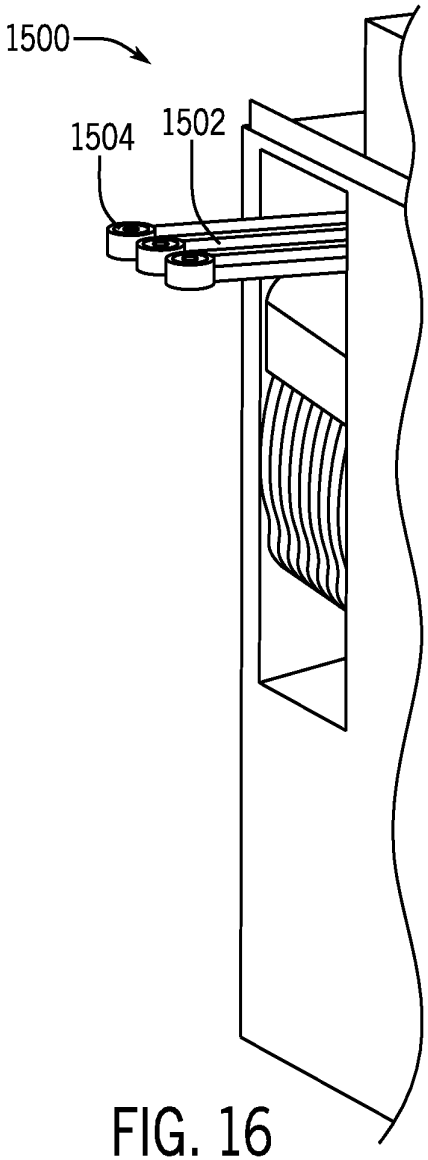


FIG. 16

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PATENT APPLICATION

ATTORNEY DOCKET NO.: 047158.100048

INVENTORS:
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Brandon N. Hinderliter (US)
Lon Robinson (US)

Application Prepared By:
Hogan Lovells US LLP
609 Main Street, Suite 4200
Houston, TX 77002

MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT

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MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT

CROSS REFERENCE TO RELATED APPLICATIONS

[0001] This application claims priority to and the benefit of co-pending U.S. Provisional Application Serial No. 62/743,299 filed October 9, 2018 titled "MODULAR SWITCHGEAR SYSTEM AND POWER DISTRIBUTION FOR ELECTRIC OILFIELD EQUIPMENT," and U.S. Provisional Application Serial No. 62/743,360 filed October 9, 2018 titled "Electric Powered Hydraulic Fracturing Pump System with Single Electric Quintuplex Fracturing Trailers," the full disclosures of which are hereby incorporated herein by reference in their entirety for all purposes.

BACKGROUND

1. Technical Field

[0002] This disclosure relates generally to hydraulic fracturing and more particularly to systems and methods for module switchgear and power distribution systems.

2. Background

[0003] With advancements in technology over the past few decades, the ability to reach unconventional sources of hydrocarbons has tremendously increased. Horizontal drilling and hydraulic fracturing are two such ways that new developments in technology have led to hydrocarbon production from previously unreachable shale formations. Hydraulic fracturing (fracturing) operations typically require powering numerous components in order to recover oil and gas resources from the ground. For example, hydraulic fracturing usually includes pumps that inject fracturing fluid down the wellbore, blenders that mix proppant into the fluid,

cranes, wireline units, and many other components that all must perform different functions to carry out fracturing operations.

[0004] Usually in fracturing systems the fracturing equipment runs on diesel-generated mechanical power or by other internal combustion engines. Such engines may be very powerful, but have certain disadvantages. Diesel is more expensive, is less environmentally friendly, less safe, and heavier to transport than natural gas. For example, heavy diesel engines may require the use of a large amount of heavy equipment, including trailers and trucks, to transport the engines to and from a wellsite. In addition, such engines are not clean, generating large amounts of exhaust and pollutants that may cause environmental hazards, and are extremely loud, among other problems. Onsite refueling, especially during operations, presents increased risks of fuel leaks, fires, and other accidents. The large amounts of diesel fuel needed to power traditional fracturing operations requires constant transportation and delivery by diesel tankers onto the well site, resulting in significant carbon dioxide emissions.

[0005] Some systems have tried to eliminate partial reliance on diesel by creating bi-fuel systems. These systems blend natural gas and diesel, but have not been very successful. It is thus desirable that a natural gas powered fracturing system be used in order to improve safety, save costs, and provide benefits to the environment over diesel powered systems. Turbine use is well known as a power source, but is not typically employed for powering fracturing operations.

[0006] Though less expensive to operate, safer, and more environmentally friendly, turbine generators come with their own limitations and difficulties as well. As is well known, turbines generally operate more efficiently at higher loads. Many power plants or industrial plants steadily operate turbines at 98% to 99% of their maximum potential to achieve the greatest

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efficiency and maintain this level of use without significant difficulty. This is due in part to these plants having a steady power demand that either does not fluctuate (i.e., constant power demand), or having sufficient warning if a load will change (e.g., when shutting down or starting up a factory process).

[0007] During fracturing operations, there may be a variety of cables, hoses, and the like extending across various locations at the well site. This may generate traffic or congestion, as routes and passages around the well site may be restricted or blocked off. Furthermore, operators may be confused when connecting or disconnecting equipment, as the large number of hoses, cables, and the like may be challenging to hook up to desired locations. Moreover, because space at the well site is at a premium, having numerous skids, trailers, and the like may present logistical challenges.

[0008] Therefore it may be desirable to devise a means by which turbine power generation can be managed at an output usable by fracturing equipment.

SUMMARY

[0009] Applicant recognized the problems noted above herein and conceived and developed embodiments of systems and methods, according to the present disclosure, for operating electric powered fracturing pumps.

[0010] The present disclosure is directed to a method and system for a modular switchgear system and power distribution for electric oilfield equipment.

[0011] In an embodiment, systems of the present disclosure mount transformers directly on a pump trailer.

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[0012] In an embodiment, a liquid cooling system, such as a radiator, is provided for cooling one or more variable frequency drives (VFDs) used to regulate an electric powered pump. In various embodiments, the cooling system is on a gooseneck of a trailer and enables liquid cooling of the VFD.

[0013] In an embodiment, a gooseneck trailer receives a variety of oilfield and switchgear equipment and includes a ladder and handrails on the gooseneck portion to enable direct access to a transformer.

[0014] In an embodiment, the gooseneck of the trailer includes a roller system to enable operators to smoothly pull cables onto the gooseneck without damaging the cables.

[0015] In an embodiment, a motor control center (MCC) is arranged on the gooseneck of the trailer within a perimeter established by the handrails with access via the ladder.

[0016] In various embodiments, the VFD and human machine interface (HMI) are on the same service platform, covered at least in part by a rain guard, to enable maintenance work and operations on the VFD with visuals of the pump controls.

[0017] In various embodiments, a single high voltage cable, for example a 13.8 kV cable, is run from the switchgear to the pumping unit because the transformer is mounted on the same platform as the VFD, MCC, and frac pump.

[0018] In an embodiment, a hydraulic fracturing system for fracturing a subterranean formation includes a support structure having a first area, a second area, a third area, and a fourth area arranged adjacent one another. The system also includes an electric powered pump, arranged in the first area, the electric powered pump coupled to a well associated with the subterranean formation and powered by at least one electric motor, also arranged in the first area, the electric powered pump configured to pump fluid into a wellbore associated with the well at a high

pressure so that the fluid passes from the wellbore into the subterranean formation and fractures the subterranean formation. The system further includes a variable frequency drive (VFD), arranged in the second area proximate the first area, connected to the at least one electric motor to control the speed of the at least one electric motor. The system includes a transformer, arranged in the third area proximate the second area, the transformer positioned within an enclosure, the transformer distributing power to the electric powered pump, the power being received from at least one generator at a voltage higher than an operating voltage of the electric powered pump. The system also includes a cooling system, arranged in the fourth area proximate the third area, the cooling system providing a cooling fluid to the VFD via one or more headers.

[0019] It should be appreciated that the areas described herein refer to regions of a trailer or support structure that are particularly selected to receive one or more components that may be utilized with hydraulic fracturing operations. In various embodiments, the first, second, third, and fourth areas may be axially aligned along an axis of support structure. The recitation of the areas is not intended to be limiting, but rather, to designate various regions for clarity with the description.

[0020] In an embodiment, a hydraulic fracturing system for fracturing a subterranean formation includes at least one generator and at least one switchgear receiving electrical power from the generator. The system further includes an electric powered pump, arranged on a support structure in a first area, the electric powered pump coupled to a well associated with the subterranean formation and powered by at least one electric motor, also arranged in the first area, the electric powered pump configured to pump fluid into a wellbore associated with the well at a high pressure so that the fluid passes from the wellbore into the subterranean formation and

fractures the subterranean formation. The system also includes a variable frequency drive (VFD), arranged on the support structure in a second area proximate the first area, connected to the at least one electric motor to control the speed of the at least one electric motor. The system further includes a transformer, arranged on the support structure in a third area proximate the second area, the transformer distributing power to the electric powered pump, the power being received from the least one generator at a voltage higher than an operating voltage of the electric pump. The system includes a cooling system, arranged on the support structure in a fourth area proximate the third area, the cooling system providing a cooling fluid to at least the VFD.

[0021] In an embodiment, a hydraulic fracturing system for fracturing a subterranean formation includes a plurality of electric powered pumps coupled to a well associated with the subterranean formation and powered by at least one electric motor, the electric powered pump configured to pump fluid into a wellbore associated with the well at a high pressure so that the fluid passes from the wellbore into the subterranean formation and fractures the subterranean formation. The system also includes a variable frequency drive (VFD) connected to the at least one electric motor to control the speed of the at least one electric motor. The system further includes a transformer for distributing power to the electric powered pump, the power being received from at least one generator at a voltage higher than an operating voltage of the electric powered pump. The system also includes at least one switchgear, receiving power from at least one generator, configured to distribute power to a plurality of pieces of wellsite equipment, the at least two switchgears coupled by a tie breaker. In embodiments, the switchgear may refer to a single breaker. However, in other embodiments, the switchgear may refer to a trailer full of switchgear components, which may include multiple breakers. Accordingly, recitation of the single switchgear may refer to a single switchgear trailer.

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BRIEF DESCRIPTION OF DRAWINGS

[0022] Some of the features and benefits of the present disclosure having been stated, others will become apparent as the description proceeds when taken in conjunction with the accompanying drawings, in which:

[0023] FIG. 1 is a schematic plan view of an embodiment of a fracturing operation, in accordance with embodiments of the present disclosure;

[0024] FIG. 2 is a block diagram of an embodiment of a switchgear unit, in accordance with embodiments of the present disclosure;

[0025] FIG. 3 is a block diagram of an embodiment of a switchgear system, in accordance with embodiments of the present disclosure;

[0026] FIG. 4 is a side elevational view of an embodiment of a pumping trailer, in accordance with embodiments of the present disclosure;

[0027] FIG. 5 is a side elevational view of an embodiment of a pumping trailer, in accordance with embodiments of the present disclosure;

[0028] FIG. 6 is a perspective view of an embodiment of an end of a pumping trailer, in accordance with embodiments of the present disclosure;

[0029] FIG. 7 is a perspective view of an embodiment of an end of a pumping trailer, in accordance with embodiments of the present disclosure;

[0030] FIG. 8 is a perspective view of an embodiment of a pumping trailer, in accordance with embodiments of the present disclosure;

[0031] FIG. 9 is a top plan view of an embodiment of a pumping trailer, in accordance with embodiments of the present disclosure;

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[0032] FIG. 10 is a perspective view of a platform of a pumping trailer, in accordance with embodiments of the present disclosure;

[0033] FIG. 11 is a perspective view of a platform of a pumping trailer, in accordance with embodiments of the present disclosure;

[0034] FIG. 12 is a perspective view of a platform of a pumping trailer, in accordance with embodiments of the present disclosure;

[0035] FIG. 13 is a perspective view of a platform of a pumping trailer, in accordance with embodiments of the present disclosure;

[0036] FIGS. 14A-C are schematic views of an embodiment of switchgear operational design, in accordance with embodiments of the present disclosure;

[0037] FIG. 15 is a perspective view of internal components of a switchgear, in accordance with embodiments of the present disclosure; and

[0038] FIG. 16 is a perspective view of an embodiment of a switchgear, in accordance with embodiments of the present disclosure.

[0039] While the disclosure will be described in connection with the preferred embodiments, it will be understood that it is not intended to limit the disclosure to that embodiment. On the contrary, it is intended to cover all alternatives, modifications, and equivalents, as may be included within the spirit and scope of the disclosure as defined by the appended claims.

DETAILED DESCRIPTION

[0040] The method and system of the present disclosure will now be described more fully hereinafter with reference to the accompanying drawings in which embodiments are shown. The method and system of the present disclosure may be in many different forms and should not be construed as limited to the illustrated embodiments set forth herein; rather, these embodiments

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are provided so that this disclosure will be thorough and complete, and will fully convey its scope to those skilled in the art. Like numbers refer to like elements throughout. In an embodiment, usage of the term "about" includes +/- 5% of the cited magnitude. In an embodiment, usage of the term "substantially" includes +/- 5% of the cited magnitude.

[0041] It is to be further understood that the scope of the present disclosure is not limited to the exact details of construction, operation, exact materials, or embodiments shown and described, as modifications and equivalents will be apparent to one skilled in the art. In the drawings and specification, there have been disclosed illustrative embodiments and, although specific terms are employed, they are used in a generic and descriptive sense only and not for the purpose of limitation.

[0042] When introducing elements of various embodiments of the present disclosure, the articles "a", "an", "the", and "said" are intended to mean that there are one or more of the elements. The terms "comprising", "including", and "having" are intended to be inclusive and mean that there may be additional elements other than the listed elements. Any examples of operating parameters and/or environmental conditions are not exclusive of other parameters/conditions of the disclosed embodiments. Additionally, it should be understood that references to "one embodiment", "an embodiment", “certain embodiments”, or “other embodiments” of the present disclosure are not intended to be interpreted as excluding the existence of additional embodiments that also incorporate the recited features. Furthermore, reference to terms such as “above”, “below”, “upper”, “lower”, “side”, “front”, “back”, or other terms regarding orientation or direction are made with reference to the illustrated embodiments and are not intended to be limiting or exclude other orientations or directions. Additionally, recitations of steps of a method should be understood as being capable of being performed in any order unless specifically stated

otherwise. Furthermore, the steps may be performed in series or in parallel unless specifically stated otherwise

[0043] Embodiments of the present disclosure describe a switchgear unit that may act as a power hub by combining and/or consolidating power output from multiple electrical generators for collection and distribution to various pieces of equipment at a wellsite. For example, in embodiments, a switchgear unit may be trailer mounted and receive power output from one or more generators. The power output may be at a variety of different levels. Upon receipt, the switchgear may act as a hub for the power to other equipment.

[0044] In various embodiments, switchgear trailers may act as power hubs to combine the output of multiple electrical generators. Adding a tie breaker between two switchgear trailers can eliminate the need for a third switchgear trailer, while still retaining the ability to evenly distribute power between all of the equipment, and to concurrently evenly distribute the electrical load between a plurality of turbine generator sets.

[0045] In certain embodiments, the switchgear configurations described herein may selectively choose between either load sharing, to provide efficiency and flexibility; or having isolated banks of equipment, to provide protection and redundancy. In an embodiment, the switchgear optionally includes a tie breaker. The tie breaker can synchronize three-phase power of a similar voltage and frequency from different sources to act as a common bus, and can evenly distribute the electrical load between a plurality of electric pumps and turbine generators when the tie breaker is in a closed position. The tie breaker will isolate one or more of the plurality of electric powered pumps, the turbine generator, and the switchgear units when the tie breaker is in an open position. The use of a tie breaker can provide an advantage over previous load sharing systems because use of a tie breaker provides more options for the equipment operators and

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allows the fleet to be more versatile as to which mode of operation – protection and redundancy, or efficiency and flexibility – is more desirable at any given moment.

[0046] Embodiments of the present disclosure also include a pump trailer that includes a variety of different pieces of equipment mounted on a common trailer, thereby simplifying layouts at the well site and reducing a number of cables run between different pieces of equipment. In various embodiments, the trailer includes a plunger type fracturing pump with up to 15 plungers, electric motor for powering the pump, various lube oil systems, a transformer, a variable frequency drive (VFD), a cooler, and a control system. Accordingly, in embodiments, a single cable may be routed from the switchgear to the pump trailer, simplifying operations and reducing congestion at the well site.

[0047] FIG. 1 is a plan schematic view of an embodiment of a hydraulic fracturing system 10 positioned at a well site 12. In the illustrated embodiment, pump units 14, which make up a pumping system 16, are used to pressurize a slurry solution for injection into a wellhead 18. An optional hydration unit 20 receives fluid from a fluid source 22 via a line, such as a tubular, and also receives additives from an additive source 24. In an embodiment, the fluid is water and the additives are mixed together and transferred to a blender unit 26 where proppant from a proppant source 28 may be added to form the slurry solution (e.g., fracturing slurry) which is transferred to the pumping system 16. The pump units 14 may receive the slurry solution at a first pressure (e.g., 80 psi to 160 psi) and boost the pressure to around 15,000 psi for injection into the wellhead 18. In certain embodiments, the pump units 14 are powered by electric motors.

[0048] After being discharged from the pump system 16, a distribution system 30, such as a missile, receives the slurry solution for injection into the wellhead 18. The distribution system 30 consolidates the slurry solution from each of the pump units 14 and includes discharge piping

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32 coupled to the wellhead 18. In this manner, pressurized solution for hydraulic fracturing may be injected into the wellhead 18.

[0049] In the illustrated embodiment, one or more sensors 34, 36 are arranged throughout the hydraulic fracturing system 10 to measure various properties related to fluid flow, vibration, and the like.

[0050] It should be appreciated that while various embodiments of the present disclosure may describe electric motors powering the pump units 14, in embodiments, electrical generation can be supplied by various different options, as well as hybrid options. Hybrid options may include two or more of the following electric generation options: Gas turbine generators with fuel supplied by field gas, CNG, and/or LNG, diesel turbine generators, diesel engine generators, natural gas engine generators, batteries, electrical grids, and the like. Moreover, these electric sources may include a single source type unit or multiple units. For example, there may be one gas turbine generator, two gas turbines generators, two gas turbine generators coupled with one diesel engine generator, and various other configurations.

[0051] In various embodiments, equipment at the well site may utilize 3 phase, 60 Hz, 690V electrical power. However, it should be appreciated that in other embodiments different power specifications may be utilized, such as 4160V or at different frequencies, such as 50 Hz. Accordingly, discussions herein with a particular type of power specification should not be interpreted as limited only the particularly discussed specification unless otherwise explicitly stated. Furthermore, systems described herein are designed for use in outdoor, oilfield conditions with fluctuations in temperature and weather, such as intense sunlight, wind, rain, snow, dust, and the like. In embodiments, the components are designed in accordance with various industry standards, such as NEMA, ANSI, and NFPA.

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[0052] FIG. 2 is a block diagram of an embodiment of a switchgear unit 200 that includes a first part 202, a second part 204, and a third part 206. As illustrated, the first part 202 and the second part 204 may receive incoming power from one or more power sources. These power sources may include any of the power sources described above, such as gas turbines, diesel generators, and the like. The switchgear unit 200 also includes the third part 206, which is utilized to output energy to various pieces of equipment at the wellsite.

[0053] Embodiments of the present disclosure include the switchgear unit 200 configured to enable capability for a variety of configurations. A non-limiting example includes: one 30 MW, 60 hz, 13,800 VAC natural gas turbine generator; one 30 MW, 60 hz, 13,800 VAC natural gas turbine generator and one 5.67 MW, 60 hz, 13,800 VAC natural gas turbine generator; one 30 MW, 60 hz, 13,800 VAC natural gas turbine generator and two 5.67 MW, 60 hz, 13,800 VAC natural gas turbine generators; one 5.67 MW, 60 hz, 13,800 VAC natural gas turbine generator; two 5.67 MW, 60 hz, 13,800 VAC natural gas turbine generators; three 5.67 MW, 60 hz, 13,800 VAC natural gas turbine generators; four 5.67 MW, 60 hz, 13,800 VAC natural gas turbine generators; and two 30 MW, 60 hz, 13,800 VAC natural gas turbine generators.

[0054] As noted above, a variety of different configurations may be utilized along with the switchgear unit in order to provide operational power at the well site. For example, the first part 202 may be configured to receive one or more options from the list including, but not limited to: one 30 MW generator, one 5.67 MW generator, two 5.67 MW generators, or a blank (null-no input). Similarly, in embodiments, the second part 204 may be configured to receive one or more options from the list including, but not limited to: one 30 MW generator, one 5.67 MW generator, two 5.67 MW generators, or a blank (null-no input). It should be appreciated that the first and second parts 202, 204 may be differently configured in various embodiments, such as

one including the 30 MW generator input while the other includes the 5.67 MW generator input, by way of non-limiting example.

[0055] The third part 206 may be referred to as the outgoing side of the switchgear unit 200 and can connection electrically to a variety of equipment types, such as power distribution systems to transmit power long distances (e.g.. 2 miles or farther); other switchgears; transformers; and the like.

[0056] In various embodiments, the switchgear unit 200 can be trailer mounted, skid mounted, bodyload mounted, or mounted on another type of platform. Furthermore, the switchgear unit 200 can be separate or combined with other equipment described herein, such as the pump units.

[0057] FIG. 3 is a block diagram of an embodiment of a configuration of the switchgear unit 200. In the illustrated embodiment, power sources 208, 210 are coupled to the first part 202 and the second part 204, respectively. It should be appreciated that while a single block is illustrated, in embodiments the power sources 208, 210 may include one or more different or similar types of power generation equipment. For example, multiple different power sources may be coupled to a single switchgear part 202, 204. The third part 206 is illustrated as routing power to a first switch gear 212 and a second switchgear 214. However, it should be appreciated that, in various embodiments, the third part 206 may transmit power to other types of equipment. The illustrated first and second switchgears 212, 214 thereafter transmit power to electrical equipment, such as electric powered pumps, wireline, and the like. The first and second switchgears 212, 214 each include twelve (12) outlets in the illustrated embodiment, however it should be appreciated that more or fewer outlets may be utilized. Furthermore, not all outlets may be used at one time.

[0058] In embodiments, the switchgear unit 200, along with the first and second switchgears 212, 214 may be referred to as a switchgear system and may be trailer mounted. The system may be

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combined into a single unit or broken out into multiple units, such as in FIG. 3. Components can also be combined with other blocks such as combining switchgear functions onto an electrical power source such as a turbine generator as long as they are in electrical communication with each other. In this embodiment, switchgear unit 200 and the first and second switchgears 212, 214 are in electrical communication using power cables.

[0059] In various embodiments, the illustrated switchgear system is utilized for 13.8kV operating voltages and includes, by way of example only, vacuum circuit breakers designed in accordance with ANSI and IEEE standards for metal enclosed switchgear rated as follows: Maximum voltage (RMS): 13.9 kV; ANSI Rating Basis: MVA rated; Operating Voltage 13.8kV; Short Circuit Current Rating: 25 KA; Close voltage: 125 VDC; and Trip Voltage: 125 VDC.

[0060] The vertical section(s) of switchgear, may include the following common features: outdoor, non-walk-in enclosure, steel; basic ONE high construction; hinged front compartment doors with custom punching; 1200 A main bus, silver plated copper, 3 phase, 3 wire; flame retardant and track resistant bus insulation system; molded insulation cover boots at bus joints with removable non-metallic hardware; ground bus, ¼ x 2, tin plated copper; enclosure space heater with expanded metal cage, rate 240 VAC; powered coat paint finish; and ANSI-61, light gray interior and exterior. It should be appreciated that in various embodiments the switchgear may also include a 3000A and/or a 2000A bus work.

[0061] In embodiments, the system may include main bus voltage monitoring. Moreover, the system may include AC control power equipment that includes, by way of example: circuit breaker cell rated 200A; silver plated copper runback bus assembly rated 200A; fixed mount vacuum circuit breaker rated 600A, 13.8kV, 25 KA; digital overcurrent protective relay; fixed

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mounted assembly; secondary molded case circuit breaker; fixed mounted CPT, 15kVA, 13800-208/120V, three phased with required primary fuses;

[0062] In embodiments, the system also includes main Circuit breakers, with each set including: circuit breaker cell rated 600A; silver plated copper runback bus assembly rated 600A; fixed mounted circuit breaker rated 600A, 13.8kV, 25 KA (Mains); digital overcurrent protective relay; lock-out relay; pilot lights, red, green, and amber; and incoming line Earthing Switch.

[0063] In various embodiments, each switchgear trailer also contains platform decking and handrails meeting OSHA safety standards, mounted on the gooseneck of the trailer.

[0064] The combined overall switchgear package for the entire spread may distribute electrical power between the following example list of hydraulic fracturing equipment: 22 electric powered hydraulic fracturing pumps with a transformer (it should be appreciated that 22 is for example purposes only and more or fewer pumps may be included), 2500 kVA, (13,800 V primary to 690 V secondary) and one 3000 HP AC Motor. Other embodiments of the electric powered hydraulic fracturing pumps can include dual hydraulic fracturing pumps (more than one pump, one or more motors), plunger type pumps with up to 15 plungers, intensifier pumps, and other forms of pumping frac slurry into a well that require electrical power. A non-limiting example of equipment includes electric pump down pumps; wire line; lights for the site; water transfer pump; electric crane; auxiliary power; electric blender; electric data van; electric hydration; electric chemical add; electric dry chem add; electric sand equipment; electric dust/silica mitigation equipment; black start generators; gas compressors; and filtration systems.

[0065] In various embodiments, a single electric powered multi-plunger pump fracturing trailer is capable of pumping inhibited acid and other proppant laden stimulation fluids and is remotely operated from a control unit. The single electric motor is capable of delivering 3,000 BHP or

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approximately 2500 HHP based on efficiency losses, pump limitations, and varying conditions at time of operations. While delivering full horsepower without exceeding the pump ratings, components will not vibrate with excessive amplitudes (e.g., amplitudes above a threshold) in resonance with the forcing vibrations of the electric motor or pump. Also, there are no or substantially no excessive rotational vibrations (e.g., vibrations above a threshold) of electric motor or pump due to transmitted torque and the flexibility of the trailer and mounting systems. The VFD system is installed on the trailer in various embodiments illustrated herein. The unit is capable of operating during prolonged pumping operations. The unit may operate in temperature ranges of -40° C to 55° C.

[0066] FIG. 4 illustrates a side elevational view of an embodiment of a pumping trailer 400 for use at hydraulic fracturing sites. The illustrated pumping trailer 400 includes a trailer 402, which is a gooseneck trailer in the illustrated embodiment. In various embodiments, the trailer 402 is a heavy-duty single drop trailer that includes heavy-duty twin beam construction; 52" king pin setting; landing legs rated for 160,000 lbs; air ride suspension; heady-duty tri or quad axle configuration; ABS brakes, air type; 11.00 R 22.5 radial tires; 2" SAE king pin with rub plate; light mounted stop/turn clearance; mud flaps; rear bumper with tow hook; running lights for highway use; front and rear fenders; and the like.

[0067] As illustrated, in various embodiments, the trailer 402 is sized to accommodate a variety of different pieces of equipment. Advantageously, mounting the equipment to a single trailer 402 facilitates mobilization and demobilization between well sites. Moreover, the configuration may enable hard-piping or coupling various pieces of equipment before arriving at the well site, thereby reducing time. Additionally, the configuration illustrated in FIG. 4 may reduce congestion at the well site. It should be appreciated that inclusion of a trailer is for illustrative

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purposes only and that the components may also be mounted on a skid, truck bed, flatbed trailer, or the like.

[0068] The illustrated embodiment further includes a multi-plunger pump 404, which may be an electric powered fracturing pump with up to 15 plungers. The pump is arranged at an end 406 of the trailer 402 opposite a gooseneck 408. As will be described below, the pump 404 includes inlet and outlet piping for receiving fluid at a low pressure and then directing high pressure fluid away from the pumping trailer 400. In various embodiments, the pump 404 is a multi-plunger type fracturing pump with up to 15 plungers with the following non-limiting features: stainless steel fluid end; main discharge connection; bleed connection; center gauge connection; and zoomie suction manifold. In embodiments, a 6" zoomie suction manifold (or appropriately designed suction manifold to feed all of the plungers within the pump) extends to the edge of the unit. The manifold terminates with two 6" winged union connections and includes two butterfly valves, or could have more unions and butterfly valves as appropriate to feed all of the plungers within the pump. A removable pulsation dampener is installed in the inlet side. The pump's rear discharge port is connected to the discharge manifold via 3" sub-connections. A 2" connection is installed on the pump center gauge opening and is utilized for the unit pressure transducer. The rear discharge manifold consists of a 3" lines and a 3" check valve. The rear discharge manifold extends to the back of the trailer. In the illustrated embodiment, an electronically powered grease pump system with pumping elements is installed to provide lubricant to the plungers. This system is equipped with a pump speed input to adjust lubrication timing based on speed. The power end of the pumps are lubricated by a hydraulic pump driven by an auxiliary electric motor. The power end lubrication system includes components such as relief valve, filters, instrumentation, plumbing, and lube oil reservoir.

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[0069] The illustrated pump 404 is powered by an electric motor 412, in the embodiment shown in FIG. 4. The motor 412 is mounted proximate the pump 404 and coupled to the pump 404 via a coupling 414. In embodiments, the coupling utilized for connecting the electric motor 412 to the pump 404 does not exceed the manufacturer's recommended maximum angle under normal operation condition. The coupling 414 includes a guard with an access panel to enable the pump 404 to be turned without guard removal.

[0070] By way of example only, the motor 412 is a horizontal AC cage induction motor. The motor has the following example performance characteristics and features: 3000 HP, voltage 690V, 3 Phase, insulation Class H, form wound, single shaft, new oilfield hub installed, anti-condensation strip heater installed, 100 ohm Platinum RTD's installed on windings (2 per phase), and two cooling blower rated 15 hp, 3600 rpm, 460 V.

[0071] The illustrated trailer 402 further includes a slide out platform for servicing the pump 404 and motor 412, a human machine interface (HMI) 416, a variable frequency drive (VFD) 418, an HMI-VFD platform 420, a platform cover 422, a transformer 424, a transformer service platform, a motor control center (MCC) 426, a cooling system 428, and railings 430. Example configurations of various components are described below, however, are for illustrative purposes only and are not limiting.

[0072] The transformer 424 may include a 3,000 kVA step down transformer and associated electrical components mounted on the trailer 402. The 3,000 kVA step down transformer may include the following features: 3-phase 60 hertz, 80/80 degree C rise, AA/FFA, 7.0 percent impedance with +/- ANSI Standard Tolerance, and phase relation Dyn1. The high voltage 13800 delta includes features such as 95 KV BIL, taps, and copper conductor. The low voltage 600Y/346 includes features such as 30 DV BIL, taps, and copper conduction. Other features

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include application, rectifier duty, 6 pulse, core/coil with HV to LV electrostatic shield and K-factor rating, monitoring with control power and temperature monitor, and interconnect cables from the switchgear to VFD with 545 DLO cables installed to connect the transformer system to the VFD. It should be appreciated that a 6 pulse VFD is an example, and other configurations would be 12 or 24 pulse. Moreover, as noted herein, the example settings provided are not intended to limit the scope of the disclosure, as design configurations may lead to modifications.

[0073] In embodiments, the transformer 424 includes an enclosure structure constructed and braced for portable movement with features including heavy-duty construction, copper ground bus, NEMA 3R (outdoor Ventilated), and primed with ANSI 61 paint finish.

[0074] The VFD system 418 is designed to meet the electrical ac drive requirements for electric frac trailers that utilize 3 phase, 60 hertz, 690 volt electrical power source. The system is built in accordance with NEMA, ANSI, and NFPA regulations. The system meets the harsh environmental conditions typically found in oilfields. The VFD 418 may include the following example settings: 650 V motor, drive current of 2429 A, overload rating of 110% for 60 sec, supply voltage of 690 V, 6 pulse, supply frequency of 60 HZ, inverter modules, and cooling system with water/glycol. Moreover, in various embodiments, example drives include the following: 2500A circuit breaker with UVR trip coil, input line reactors, semiconductor fuses with blown-fuse switches, control components, liquid cooled rectifiers, 3 inverter IGBT modules, 3 SMPS modules, shielded ribbon cables, digital controller with parameter based operations and I/O board, door mounted HMI for setup, monitoring, and diagnostics, MV 3000 I/O panel, control power transformer, 24 V power supply, relays, indicating lights, and emergency stop push button. In various embodiments, the VFD 418 also includes welded stainless steel piping coolant headers with hose connections to the modules. However, it should be appreciated that

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other piping may be used, such as carbon steel or the like. Each module is connected to the supply and return headers with a ¾" hose and isolation valve. The VFD enclosure is an IP66 enclosure that may include two internal heat exchangers are supplied for removing heat form the air inside of the drive enclosure and four frames are suppled in the enclosure for power cabling, control cables, and piping. Moreover, the VFD enclosure is covered by a rain shield, which extends out over the service platform to protect the components from rain while being serviced. In embodiments, the unit has a dry type 3 phase, 60 HZ, power distribution transformer with 690 V primary, and 240/120 V secondary with taps.

[0075] In embodiments, the MCC control enclosure is an outdoor weather-proof enclosure. The structure is constructed and braced for portable movement and has features such as access panels, all external off unit connections wired to plug-in connectors accessible from outside, primed and finished painted inside and out, LED external lighting, cooling provided via liquid cooled radiator, and frac pump motor is hard wired on the unit.

[0076] By way of example, the MCC 426 is fed by a circuit breaker independent from the VFD circuits. The MCC 426 may include features such as one MCC, Seismic Zone 4, 400 A Main bus, Rating: 42,000 AIC, 600 V, 60 HZ, 3 phase, and 3 wire. Furthermore, there may be four size 1 full voltage non-reversing starters of 10 HP with hands off auto switch. Additionally, there may be 2 full voltage non-reversing starters of 25 HP with hands off auto switch. The MCC may also include one lighting panel, 150 A, with circuit breakers as required.

[0077] Supplied and installed on each of the pump discharge units is a 0-15,000 PSI pressure transducer with hammer union connections. The transducers are installed with a protective guard in various embodiments. Also, in embodiments, there is a single touchscreen display for local pump control. However, other pump control may also be included. In various embodiments,

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the unit comes installed with either Ethernet communications or RS-485 serial. It may also be equipped with wireless communications to sensors in lieu of cabled communication and sensor connections.

[0078] In various embodiments, the trailer 400 may also include an access hatch on the coupling guard, cable gland protection, check valve bracket support, spools for the frac cables, step grip tape on the handrails and ladder, grounding for the trailer, ladder/stair access with handrails, land gear crank, oil radiator bracket, power end tank temp sensor, fire extinguisher, slide out work platform to work on the pump, motor, and motor cooling blowers, slide out work platform has a safety hinged door to prevent falls, the VFD has over pressure trip wiring and wireless capabilities, Vic Clamps, transformer louver design large metal mesh filter to prevent dust/dirt intrusion, and load shedding (via intelligent pump control throttle control and other load responses).

[0079] FIG. 5 is a side view of an embodiment of the pump trailer 400. As illustrated, the pump 404 is arranged proximate the motor 412, which facilitates operation of the pump. The HMI 416 is arranged below the cover 422 and proximate the VFD 418 on the VFD platform 420. In the illustrated embodiment, the transformer 424 is arranged on the trailer 402, however it should be appreciated that in other embodiments the transformer 424 may be separately mounted, for example on a different trailer, skid, truck, or the like. The gooseneck 408 includes the cooling system 428 and MCC 426, in the illustrated embodiment. As described above, in various embodiments the VFD 418 is liquid cooled, for example via the headers 500 extending from the cooling system 428 to the VFD housing. The cooling system 428 may also be used to cool various other components.

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[0080] FIG. 6 is a perspective view of an embodiment of the end 406 of the trailer 402 including the pump 404, motor 412, and partially including the VFD platform 420. In the illustrated embodiment, auxiliary systems described above are also illustrated. The pump 404 includes a suction end 600 and a discharge end 602. As shown in FIG. 6, piping 604 extends from the suction end 600 and the discharge end 602 to receive and direct fluid to and from the pumping trailer 400. It should be appreciated that various components, such as valves, couplings, sensors, and the like may be incorporated into the piping 604 and the end 406 of the trailer 402. In the illustrated embodiment, ladders 606 (shown in their stowed position) enable ingress and egress to various locations where maintenance operations may occur. Accordingly, operations utilizing the pumping trailer 400 may be easier for operators.

[0081] FIG. 7 is a perspective view of an embodiment of the end 406 of the trailer 402. The illustrated embodiment includes the slide out platform 700, which is illustrated in a stored configuration. The illustrated handrail 430 may be used to side the platform 700 in and out, thereby facilitating maintenance operations on the pump 404. Sliding and storing the platform 700 enables a width of the trailer 402 to be reduced, which may reduce wide load permitting to transport the trailers between different locations. As illustrated, cabling 702 extending from the motor 412 is routed below the VFD platform 420, thereby reducing the likelihood the cabling 702 is disturbed. As will be appreciated, in various embodiments, because the components on the trailer 402 are substantially fixed relative to one another, the cabling and other connections may be made prior to arriving at the well site, thereby reducing time spent preparing for fracturing operations. Moreover, portions of the cabling and/or connections may be formed from stronger or more rigid materials because they will not be removed or may be moved less often than other cabling, which may be routed in different configurations at each well site.

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[0082] FIG. 8 is a perspective view of an embodiment of the pumping trailer 400. As described above, various components are arranged along a length 800 of the trailer 402. It should be appreciated that the illustrated ordering or relative positions of the components is for illustrative purposes only, and in other embodiments, components may be in different locations, as may be suitable for operating conditions. However, it may be advantageous to position components proximate to associated or operationally linked components. Moreover, arrangement configurations may be made with respect to expected maintenance operations.

[0083] FIG. 9 is a top plan view of an embodiment of the trailer 402 further illustrating the configuration of the components along the length 800. As illustrated, a transformer service platform 900 provides space for operations to connect to the transformer 424, adjust operations using the MCC 426, and/or perform maintenance on the cooling system 428. The illustrated transformer service platform 900 is arranged on the gooseneck 408 and has a higher elevation, relative to the ground plane, than the VFD platform 420. As noted above, a relative width of the trailer 402 is substantially constant along the length 800, which may reduce requirements to get wide load permits for transportation along roadways. In various embodiments, similar slide or platforms, such as those described with respect to the platform 700, may further be integrated into other locations of the trailer 402 to facilitate pumping and/or maintenance operations.

[0084] In various embodiments, the trailer 402 may be referred to as having different areas or regions. However, such description is for illustrative purposes only and is not intended to limit the scope of the present disclosure. For example, a first area may be the region having the pump 404 and the motor 412. More, a second area may be the region having the VFD 418, which may be covered by the platform cover 422. Additionally, a third area may be region having the transformer 424 while the fourth area may be the region having the cooling system 428. It

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should be appreciated that, in various embodiments, these areas may partially or completely overlap. For example, the first area may also include the platform, the fourth area may also include the transformer 424, and the like.

[0085] FIG. 10 is a perspective view of an embodiment of the pump trailer 400 illustrating the transformer 424 arranged proximate the VFD platform 420. As shown, the VFD platform 420 includes the platform cover 422, thereby enabling operators to perform maintenance or control operations in inclement weather. Furthermore, as described above, the cooling headers 500 are illustrated coupled to the VFD housing.

[0086] FIG. 11 is a perspective view of an embodiment the pump trailer 400 illustrating the transformer 424 arranged proximate the VFD platform 420. Moreover an auxiliary pump 1100 coupled to a tank 1102 is illustrated below the transformer 424 and the VFD platform 420.

[0087] FIG. 12 is a perspective view of an embodiment of the transformer service platform 900 arranged at the gooseneck 408. In the illustrated embodiment, the cooling system 428 includes a radiator that distributes cooling liquid (e.g., water/glycol) via the headers 500. The MCC 426 is arranged proximate the cooling system 428. Also illustrated in the ladder 606, described above.

[0088] FIG. 13 is a perspective view of an embodiment of the transformer service platform 900 including the cooling system 428 and the MCC 426. In the illustrated embodiment, the transformer 424 is accessible via the platform 900 and includes a connection 1300 for receiving a single 13.8kV cable. The illustrated embodiment further includes cable trays 1302 arranged below hinged covers 1304 within the floor of the platform 900. As a result, cables may be arranged along the platform 900 within the trays to reduce the likelihood of damage.

[0089] As described above, the switchgears may further include features such as a solid insulated main circuit. The insulation may include epoxy or ethylene propylene diene terpolymer (EPDM).

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The solid insulation may reduce exposure risk to live parts, which may be beneficial to in harsh environments that may include humidity, dust, pollution, and the like. Accordingly, the sensitivity to these harsh environments may be adjusted due to the insulation. Furthermore, the insulated main circuit may reduce phase-to-phase fault risks. In various embodiments, the solid insulation is ground shielded, which may extend life expectancy. Furthermore, in various embodiments, use of the solid insulation may extend switchgear life and increase reliability.

[0090] Additional features may also include vacuum circuit breakers, an isolating ground switch within a sealed tank with air at atmospheric pressure, and medium voltage cables directly grounded with the isolation ground switch before opening the cable department panels. Moreover, arranging the devices in series, as noted above, may provide double isolation between the busbars and various cables. In certain embodiments, SF6 is excluded and the system is RoHS compliant, which reduces environmental concerns.

[0091] Embodiments of the present disclosure may also include integrated core units. These units enable simple operation, with three positions for each unit: connected, open, and grounded. An intuitive active mimic bus diagram may also be included, with clear indicators for the circuit breaker and grounding switch. Furthermore, interlocks between functions may be positively driven and built-in as standard.

[0092] The system may also include cubicle architecture for all circuit breakers, as well as multiple circuit breaker load options and two types of operating mechanisms. For example, D01N and D02N: 100 A and 200 A circuit breakers may be utilized for light load and operation. In embodiments, D06N: 600 A circuit breaker may be utilized for simple protection and light operation. Furthermore, in operation, D06H / D12H: 600 A and 1200 A circuit may be used for standard/heavy duty load and operation.

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[0093] Use of modular system architecture may simplify installation and upgrades. In embodiments, core units may be optimized for dedicated applications, but may also be arranged to share features such as dimensions and footprint (e.g., 14.75 in. (375 mm) base form factor width), auxiliaries (e.g., electrical operation devices, accessories, options, etc.), intuitive operation, and elbow-style cable connections.

[0094] In embodiments, additional features of the present disclosure may include a live cable interlock to help prevent the grounding of live cables in main circuit breakers, as well as for feeder breakers. Furthermore, a cable test device interlocked with isolating ground switch, simplifying cable testing and diagnosis. For example, cable testing may commence without accessing the cable compartment. Additionally, test device connection may be made from the front of the switchgear, while cables remain grounded. Also, in embodiments, interlocks may include a grounded wye point.

[0095] Additionally, in embodiments, an auto-transfer scheme is included without traditional iron care VT to provide an open or closed transition (hold time contact for voltage sync devices). Additionally, self-powered protection with embedded communications and integrated metering and power measurement functions may be included. In embodiments, there is integration of power measurement in feeders without additional space.

[0096] Embodiments the present disclosure also include switchgear automation features. For example, modular architecture may be used for scalable solutions (e.g., distributed intelligence). Furthermore, switchgears may be linked by field bus using standard ethernet Modbus protocol and also have capabilities to enable integration in SCADA systems via multiple protocols (Modbus, IEC 61850, wireless). The switchgear may also include embedded web interface metering.

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[0097] In various embodiments, each switchgear subassembly is made up of functional units, each representing a type-tested assembly composed of a basic core unit and other functional blocks designed to work together in any combination. The core units may be optimized for each typical application, and the assembly forms an insulated functional unit with reduced sensitivity to the environment. Accordingly, the system makes it possible to meet electric powered hydraulic fracturing need while also providing flexibility and simplicity in the design of functional units, a small footprint for space savings, environmentally robust components, along with easy extensions and upgrades.

[0098] As described above, the switchgear may include various components. Each functional section is equal to an assembly of functional blocks composed of: 1) a core unit that may include a circuit breaker, riser unit, and bus ground switch; 2) an LV cabinet that provides protection, measurement, and control; 3) a busbar connection that can be copper or aluminum; 4) bottom connections includes cables and busbars; 5) a bottom compartment including a cable box and an extra base plinth; 6) sensors such as CTs and VTs; and 7) a communication network that works through Radio/GSM/GPRS/Ethernet/Wireless/and other connected connections. The communication network may be used for fault detection, protection, measurement, local control, and/or remote control.

[0099] As noted above, in embodiments, the switchgear may include a solid and shielded insulation to provide protection from environmental impacts, negate electric fields in the switchgear, and extend maintenance intervals. Furthermore, the ground shielded system also helps to extended the equipment service life, resulting a lower total cost of ownership.

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[0100] The system describes herein may be arranged such that no part of the main circuit is exposed to free air. As a result, there is a reduced risk of internal arching and maintenance operations may be optimized, leading to a reduced risk of downtime.

[0101] In various embodiments, the switchgear includes a common load sharing bus. This bus may be housed in switchgear A (Figure 2). However, two switchgears with a tie breaker acts as a common bus, and embodiments having a single switchgear trailer also have an integrated common bus.

[0102] As described above, in various embodiments the switchgear includes integrated core units including three positions: connected, open, and grounded. FIGS. 14A-14C illustrates the three-in-one switchgear design. In the illustrated embodiment, the circuit breaker is in series with the isolating ground switch, which, combined with interlocks, provides integrally designed protection. There are also only three possible operating positions: closed, open, and grounded.

[0103] FIG.14A illustrates the closed position, FIG. 14B illustrates the open position, and FIG. 14C illustrates the grounded position. A switch 1400 moves between the positions to facilitate transmission of electrical energy between the components.

[0104] FIG. 15 is a perspective view of an embodiment of a switchgear 1500 including features described herein. For example, the illustrated switchgear 1500 includes shielded solid insulation 1502 surrounding a busbar 1504. The shielded solid insulation 1502 further extends along vacuum bottles. An integrated isolated ground switch assembly 1506 includes the isolating ground switch enclosed in a tank 1508, as described above, and further covered in solid insulation 1502. Sensors 1510 are arranged along a bottom of the tank 1508 in the illustrated embodiment, which may be used for optimized protection and control, as noted above.

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Furthermore, the illustrated embodiment includes front aligned cable connections 1512, which are also shielded by the insulation 1502, to facilitate easy cable installation.

[0105] FIG. 16 is a perspective view of the switchgear 1500 includes the busbars 1504 covered, at least partially, by the solid insulation 1502. As described above, the insulation may improve the expected working life of the equipment, among other benefits.

[0106] The present disclosure described herein, therefore, is well adapted to carry out the objects and attain the ends and advantages mentioned, as well as others inherent therein. While a presently preferred embodiment of the disclosure has been given for purposes of disclosure, numerous changes exist in the details of procedures for accomplishing the desired results. These and other similar modifications will readily suggest themselves to those skilled in the art, and are intended to be encompassed within the spirit of the present disclosure disclosed herein and the scope of the appended claims.

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CLAIMS

1. A hydraulic fracturing system for fracturing a subterranean formation, comprising:

a support structure having a first area, a second area, a third area, and a fourth area arranged adjacent one another;

an electric powered, multi-plunger pump with up to 15 plungers, arranged in the first area, the electric powered pump coupled to a well associated with the subterranean formation and powered by at least one electric motor, also arranged in the first area, the electric powered pump configured to pump fluid into a wellbore associated with the well at a high pressure so that the fluid passes from the wellbore into the subterranean formation and fractures the subterranean formation;

a variable frequency drive (VFD), arranged in the second area proximate the first area, connected to the at least one electric motor to control the speed of the at least one electric motor;

a transformer, arranged in the third area proximate the second area, the transformer positioned within an enclosure, the transformer distributing power to the electric pump, the power being received from at least one generator at a voltage higher than an operating voltage of the electric pump; and

a cooling system, arranged in the fourth area proximate the third area, the cooling system providing a cooling fluid to the VFD via one or more headers.

2. The system of claim 1, further comprising:

a control system arranged in the fourth area, the control system including one or more operating parameters of the electric pump, VFD, transformer, or cooling system.

3. The system of claim 1, further comprising:

a switchgear subassembly, the switchgear subassembly having integrated core units configured to operate in a connected position, an open position, or a grounded position.

4. The system of claim 3, wherein the switchgear subassembly comprises:

a busbar shielded, at least partially, by solid insulation;

an isolating round switch, enclosed within a tank arranged proximate the busbar; and

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cable connections for coupling to the switchgear.

5. The system of claim 1, wherein the fourth section is arranged at a higher elevation than the first section, the fourth section associated with a gooseneck portion of a trailer.

6. The system of claim 1, wherein the support structure is at least one of a trailer, a skid, a pad, a truck bed, or a combination thereof.

7. The system of claim 1, further comprising:

cable trays positioned below a walking surface of the fourth section, the cable channels being covered by a hinged cover that pivots to provide access to the cable channels.

8. The system of claim 1, wherein the cooling system comprises a radiator that utilizes a water/glycol mixture.

9. A hydraulic fracturing system for fracturing a subterranean formation, comprising:

at least one generator;

at least one switchgear receiving electrical power from the generator;

an electric powered pump, arranged on a support structure, the electric powered pump coupled to a well associated with the subterranean formation and powered by at least one electric motor, the electric powered pump configured to pump fluid into a wellbore associated with the well at a high pressure so that the fluid passes from the wellbore into the subterranean formation and fractures the subterranean formation;

a variable frequency drive (VFD), arranged on the support structure proximate the electric powered pump, connected to the at least one electric motor to control the speed of the at least one electric motor;

a transformer, arranged on the support structure proximate the VFD, the transformer distributing power to the electric powered pump, the power being received from the least one generator at a voltage higher than an operating voltage of the electric powered pump; and

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a cooling system, arranged on the support structure proximate the transformer, the cooling system providing a cooling fluid to at least the VFD.

10. The system of claim 9, wherein the at least one switchgear comprises integrated core units configured to operate in a connected position, an open position, or a grounded position.

11. The system of claim 10, wherein the switchgear subassembly comprises:

a busbar shielded, at least partially, by solid insulation;

an isolating round switch, enclosed within a tank arranged proximate the busbar; and

cable connections for coupling to the switchgear.

12. The system of claim 9, further comprising:

a transformer service platform that provides access to the transformer, the transformer service platform positioned at a higher elevation than at least a portion of a base of the electric powered pump.

13. The system of claim 9, wherein the support structure is at least one of a trailer, a skid, a pad, a truck bed, or a combination thereof.

14. The system of claim 9, further comprising:

cable trays positioned below a walking surface of the support structure, the cable channels being covered by a hinged cover that pivots to provide access to the cable channels.

15. The system of claim 9, wherein the cooling system comprises a radiator that utilizes a water/glycol mixture.

16. The system of claim 9, further comprising:

a human machine interface, positioned proximate the VFD; and

a platform cover at least partially covering the humane machine interface and VFD.

17. A hydraulic fracturing system for fracturing a subterranean formation, comprising:

a plurality of electric powered pumps coupled to a well associated with the subterranean formation and powered by at least one electric motor, the electric powered pump configured to pump fluid into a wellbore associated with the well at a high pressure so that the fluid passes from the wellbore into the subterranean formation and fractures the subterranean formation;

a variable frequency drive (VFD) connected to the at least one electric motor to control the speed of the at least one electric motor;

a transformer for conditioning power to the electric powered pump, the power being received from at least one generator at a voltage higher than an operating voltage of the electric pump; and

a switchgear, receiving power from at least one generator, configured to distribute power to a plurality of pieces of wellsite equipment, the switchgear having a common load sharing bus.

18. The system of claim 17, wherein the common load sharing bus is configured to synchronize three-phase power of a similar voltage and frequency from different sources, the switchgear evenly distributing an electrical load between the plurality of electric pumps and turbine generators.

19. The system of claim 17, wherein the common load sharing bus is configured to isolate one or more of the plurality of electric powered pumps, the at least one turbine generator, and the switchgear.

20. The system of claim 17, wherein the plurality of electric pumps, VFD, and transformer are mounted on a common support structure and a single cable couples the switchgear to the common support structure.

ABSTRACT

[0107] A hydraulic fracturing system for fracturing a subterranean formation includes a support structure that includes an electric powered pump, arranged in a first area, the electric powered pump powered by at least one electric motor, also arranged in the first area. The system further includes a variable frequency drive (VFD), arranged in a second area proximate the first area, connected to the at least one electric motor to control the speed of the at least one electric motor. The system includes a transformer, arranged in a third area proximate the second area. The system also includes a cooling system, arranged in a fourth area proximate the third area, the cooling system providing a cooling fluid to the VFD via one or more headers.