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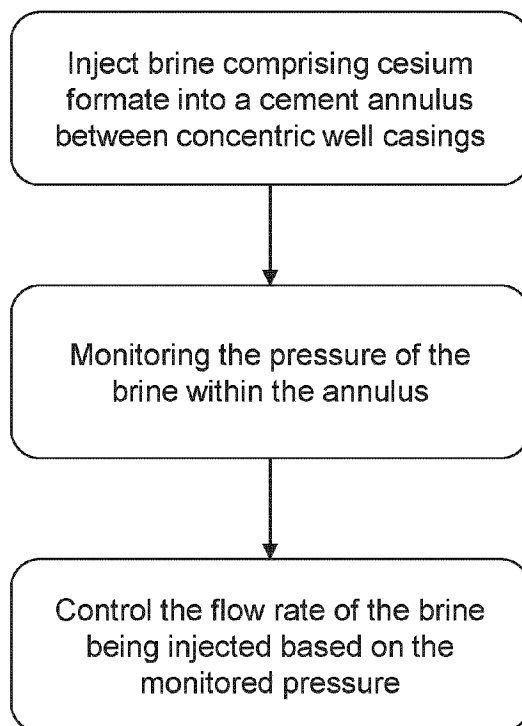
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(54) Title: INTER-CASING PRESSURE CONTROL SYSTEMS AND METHODS

Figure 6



(57) **Abrégé/Abstract:**

An apparatus and method for controlling and/or reducing undesirable and dangerous buildup of formation gases and fluids in the annular space between casing strings in an oil & gas well. The process comprises injecting a brine of cesium formate into a cement annulus between concentric well casings; and monitoring the pressure of the brine within the annulus. Based on the pressure, the flow rate of the brine being injected is controlled to displace or control formation gases and fluids within the annulus.

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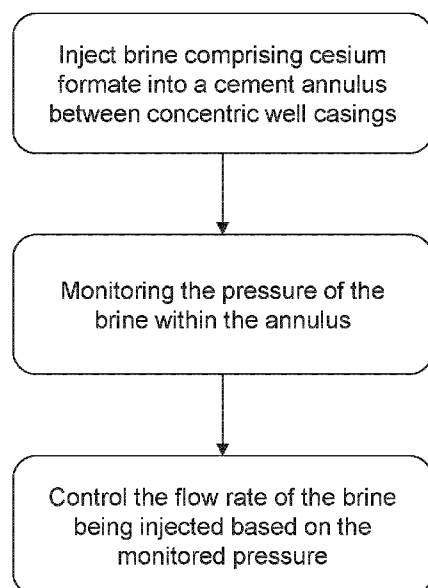
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(54) Title: INTER-CASING PRESSURE CONTROL SYSTEMS AND METHODS

Figure 6



(57) Abstract: An apparatus and method for controlling and/or reducing undesirable and dangerous buildup of formation gases and fluids in the annular space between casing strings in an oil & gas well. The process comprises injecting a brine of cesium formate into a cement annulus between concentric well casings; and monitoring the pressure of the brine within the annulus. Based on the pressure, the flow rate of the brine being injected is controlled to displace or control formation gases and fluids within the annulus.



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Inter-Casing Pressure Control Systems and Methods

FIELD OF THE INVENTION

[0001] The invention relates to the control and/or reduction of undesirable and dangerous buildup of formation gases and fluids in the annular space between casing strings in an oil & gas well.

BACKGROUND

[0002] Without control of Inter-Casing Pressure (ICP, also referred to as sustained casing pressure - SCP) in an oil & gas well the possibility of an uncontrolled released of gas and fluids can occur. As this release of containment can happen with no personnel in the area of the well it is possible that the problem could quickly escalate and cause a breach in containment (loss of well integrity) which ultimately could lead to breaches in the surrounding rock structure and lead to the formation of surface vents whereby gas and oil will be released into the surrounding environment resulting in a serious Health, Safety and Environmental (HSE) problem in the area. For example, escaping hydrocarbons may be accidentally ignited. If this breakdown is below a casing shoe, then an influx of any kind may become unmanageable because surface controls may no longer work. This would lead to an uncontrollable well control event.

[0003] Many governmental regulators & HSE rules around the world will not allow a well to be perforated and brought online or continue to produce while high inter-casing pressure exists. In some cases, the only option in this case is to totally abandon this well with the loss of all the funds that have been expended to date on the actual drilling of the well and the additional funds that will be required to conduct the abandonment procedure. This can amount to upwards of over \$3 million USD for onshore wells with that figure increasing drastically for an offshore well.

[0004] Historically barite plugs have been used. A barite is a plug made from barite weighting materials that is placed at the bottom of a wellbore. Unlike a cement plug, the settled materials do not set solid, yet a barite plug can provide effective and low-cost pressure isolation. A barite plug is relatively easy to remove and is often used as a temporary facility for pressure isolation or as a platform enabling the accurate placement of treatments above the plug.

[0005] Cement plugs have also been used to prevent the buildup of formation gases and fluids.

SUMMARY

[0006] In accordance with the invention, there is provided a process comprising:

injecting brine comprising cesium formate into a cement annulus between concentric well casings; monitoring the pressure of the brine within the annulus; and controlling the flow rate of the brine being injected based on the monitored pressure.

[0007] The pressure of the brine within the annulus may be measured by electronic pressure gauges at the well head. A measure of the pressure of the brine within the annulus may be obtained by measuring the pressure applied to the brine within the annulus. For example, the pressure may be taken in the treatment line in direct fluid communication with the annulus (e.g. after a pressure intensifier or after a release valve).

[0008] The density of the brine may be greater than 1.8g/ml. The density of the brine may be greater than 1.2g/ml. The density of the brine may be less than 2.7g/ml.

[0009] The flow and pressure of the injected brine may be controlled using an air pump (or another suitable pump). The pump may be chosen to meet specific calculated well treatment needs (e.g. higher volume flow rate than normal, operational limitations dictated by site location, better control of injection and bleed cycles) and/or site safety requirements or regulations.

[0010] A mechanical pump that will be able to reach the pressure that will be required (+ 4,500psi) is generally a plunger style pump or a hydraulic vane style pump. Both styles of pumps require substantially more power and electronic controls to operate at a very slow speed. As the apparatus may be working in remote areas without power available a mechanical pump would require substantially more power generation to be available on the location which could become cost prohibitive. Also, the cost of the electronic control systems that would be required for these pumps may be cost prohibitive and maintenance intensive. In addition, using such mechanical pumps may often result in surge pressure being induced on the annulus which we are trying to avoid so as not to pack off any particulate matter resident in the cement annulus.

[0011] The brine may be injected using a treatment line, wherein the treatment line includes at least one one-way check valve to prevent fluids escaping from the annulus via the treatment line.

[0012] The process may comprise injecting brine into multiple cement annuli in the same wellhead. The process may comprise switching brine injection between multiple cement annuli. The brine being injected may also be of varying densities and pH levels dictated by conditions on the well annulus being treated. The process may comprise adjusting the brine density and/or brine pH levels based on the condition of the well annulus.

[0013] The process may comprise ramping up the pressure of the brine within the annulus to a predetermined pressure over the course of between eight hours to five or more days.

[0014] The process may comprise venting gas from the cement annulus.

[0015] The process may comprise bleeding fluids (e.g. liquids) from the cement annulus. The process may comprise cycling between bleeding fluids from the annulus and injecting brine. The process may comprise: measuring the volume of liquid and/or gas being ejected from the annulus.

[0016] The process may comprise: measuring the density of the fluid being bled from the annulus; and stopping the bleeding when the density exceeds a predetermined threshold (e.g. 1.25 sg). The fluid being ejected from the annulus may be caught in a fluid sampling system (e.g. suitably pressure certified (such as: up to 3,000psi)) for recovery and investigation during the bleeding process.

[0017] The process may comprise:

analyzing the chemical composition of the fluid or gas being bled from the annulus; and stopping the bleeding based on predetermined criteria (e.g. the concentration of cesium formate exceeding a predetermined threshold).

[0018] The process may comprise:

injecting the brine into the cement annulus to reach an initial predetermined pressure using a first injecting apparatus; and once the initial predetermined pressure is reached, injecting the brine into the cement annulus to maintain a steady-state predetermined pressure using a second injecting apparatus.

[0019] The initial predetermined pressure may be greater than 2,000psi. The initial predetermined pressure may be greater than 4,000psi. The initial predetermined pressure may be less than 6,000psi. The initial predetermined pressure may be less than 10,000psi.

[0020] The steady-state predetermined pressure may be substantially equal to the initial predetermined pressure.

[0021] The injection of the brine into the cement annulus to reach an initial predetermined pressure may increase the pressure monotonically. For example, once injection has commenced, the pressure should not decrease. This may help ensure that blockages do not form within the fissures in the cement annulus. The injection of the brine into the cement annulus to reach an initial predetermined pressure may increase the pressure linearly with time.

[0022] The injected brine may be monovalent. For example, each of the ions (cations and anions) in the brine may have a charge of ± 1 . The brine may comprise element ions from group 1 and/or group 17 in the periodic table of elements.

[0023] The process may comprise filtering the brine to less than 2 microns prior to injection. E.g. the filtration may use a filter with 2 microns holes (e.g. a 2-micron weaved stainless steel filter). The process may comprise filtering the brine to less than 10 microns.

[0024] The brine may be injected at less than between 1 to 40 litres/hour.

[0025] Production from the well may continue during the brine injection.

[0026] The process may comprise monitoring the ambient temperature at the well site. The process may comprise heating the brine being injected based on the ambient temperature at the well site.

[0027] The process may comprise, prior to injecting the brine: measuring the pressure in the annulus; removing fluid from the annulus until a predetermined pressure is reached; and determining the rate of increase of pressure; and controlling the rate of brine injection based on the determined rate of increase of pressure.

[0028] The brine may be injected using a treatment line; and the process may comprise sealing the well head when the monitored pressure reaches a steady state without further injections of brine. The brine may be injected using a treatment line; and the process may comprise monitoring the temperature of the treatment line and heating the treatment line when the treatment-line temperature falls below a predetermined threshold.

[0029] According to a further aspect of the present disclosure, there is provided a process comprising: injecting brine comprising cesium formate into a cement annulus between concentric well casings.

[0030] According to a further aspect of the present disclosure, there is provided an apparatus comprising: an annulus connector configured to connect to a cement annulus between concentric well casings; and a pressurizing unit configured to inject brine into the cement annulus between concentric well casings via the annulus connector. The annulus connector may be configured to connect at the top of the annulus.

[0031] According to a further aspect of the present disclosure, there is provided an apparatus comprising: an annulus connector configured to connect to a cement annulus between concentric well casings; a pressurizing unit configured to inject brine into the cement annulus between concentric well casings via the annulus connector; and a pressure monitor configured to monitoring the pressure of the brine within the annulus; and a controller configured to control the pump to control the flow rate of the brine being injected based on the monitored pressure.

[0032] The annulus connector may be ring-shaped to allow production to continue through the hole in the ring connector while brine injection is ongoing.

[0033] The apparatus may comprise: a dynamic pressurizing unit comprising a pump; and a passive pressurizing unit comprising a reservoir configured to hold a volume of brine at an elevated pressure and a passive-pressurizing-unit release valve configured to deliver brine under pressure to the cement annulus between concentric well casings.

[0034] The dynamic pressurizing unit may be configured to elevate the pressure within the passive pressurizing unit reservoir.

[0035] The dynamic pressurizing unit may be configured independently to enable delivery of brine under pressure directly to the cement annulus between concentric well casings.

[0036] The apparatus may comprise a treatment line between the pressurizing units and the cement annulus, the treatment line having one or more one-way valves configured to prevent retrograde flow from the cement annulus.

[0037] The apparatus may comprise a treatment line between the pressurizing units and the cement annulus, the treatment line having one or more pressure regulators.

[0038] The apparatus may comprise a dynamic pressurizing unit configured to generate pressure (e.g. using a pump). The dynamic pressurizing unit may be Pressure Assisted Displacement Treatment System (PADTS).

[0039] The apparatus may comprise a passive pressurizing unit configured to store and release brine under pressure. The passive pressurizing unit may comprise or be an Accumulator Containment Unit (ACU).

[0040] The dynamic pressurizing unit and/or passive pressurizing unit shells may be of steel construction with insulation which renders them suitable for a wide range of temperatures from -40C to +50C.

[0041] The dynamic pressurizing unit and/or passive pressurizing unit shells may be designed, built and certified for use in a Zone 1 Division 1 environment including all lighting, electrical and electronics installed.

[0042] The dynamic pressurizing unit and/or passive pressurizing unit shells may be designed for either on or offshore applications and are custom designed specifically for the operation.

[0043] The dynamic pressurizing unit may use a high-pressure low flow capable air pump used to both charge the accumulators in the passive pressurizing unit and for use in the initial treatment for the well prior to instituting the slow feed process using the stored hydraulic energy in the passive pressurizing unit.

[0044] The air pump may be used in conjunction with a hydraulic intensifier. A hydraulic intensifier may comprise a: fixed ram, a hollow inverted sliding cylinder, and a fixed inverted cylinder. The hydraulic intensifier may have a fixed ram through which the brine, under a high pressure, flows to the wellhead. A hollow inverted sliding cylinder, containing brine under high pressure, is mounted over the fixed ram. The inverted sliding cylinder is surrounded by another inverted fixed cylinder which contains air from the air pump at a lower pressure.

[0045] The dynamic pressurizing unit may have both electronic pressure gauges and manual charts for recording and storing system pressure tests.

[0046] multiple (e.g. up to 5 or more) passive pressurizing unit's may be mounted on and become an integral part of the dynamic pressurizing unit.

[0047] Gauges relating to the passive pressurizing unit may be installed in the passive pressurizing unit for high visibility during treatment or may be easily transferred into the interior mounting bracket on the passive pressurizing unit when it is left to operate remotely on a well site.

[0048] All electronic gauges may have a built-in data logger function. All electronic gauges may be configured to operate independently for up to six months on internal power and record up to 1,000,000 data points or more in storage.

[0049] Electronic pressure gauges may monitor ambient temperature around units. The apparatus may have a secondary heating system configured to heat the brine being injected based on the ambient temperature.

[0050] The system may be mobile. The system may comprise: a skid mounting assembly for supporting the apparatus; a generator and an air compressor.

[0051] All connections on fluid treatment lines may comprise quick connect type couplings that will not leak fluid when being connected.

[0052] Manifolds used in connecting treatment lines to the wellhead are custom designed. N₂ gas connection manifold on top of the accumulators are custom designed. The custom manifolds allow for the simultaneous attachment of a manual pressure gauge, an electronic pressure gauge and a port to be used in recharging the internal bladder with nitrogen as required.

[0053] Electronic pressure gauges may be used to monitor one or more pressures on the units such as:

- nitrogen charge pressure on accumulator bottles;
- actual hydraulic pressure being stored in the bottles;
- pressure being used to inject fluid into the well;
- one or more annulus pressure at the well head; and
- pressure being created directly by the air pump being used to energize the treatment lines and hydraulic accumulators.

[0054] All electronic gauges may have manual back up conventional gauges to check and confirm pressures.

[0055] The apparatus or system may comprise a power generator. The apparatus or system may comprise a renewable power generator (e.g. one or more of a solar panel and a wind turbine).

[0056] The brine may comprise potassium formate. The brine may consist of cesium formate, potassium formate and water (e.g. where other materials in the brine account for less than 5% by weight).

[0057] The process may be conducted while surface temperatures range between -40°C up to +50°C. The apparatus may be configured to operate in the temperature range of 40°C up to +50°C.

[0058] The apparatus may have a secondary heating system to maintain treatment line temperatures above -10°C. This may help to prevent crystallization of the fluid being injected into the well bore. An advantage of using cesium formate is its stability in high temperature and high-pressure environments.

[0059] The apparatus and process may be used where you have a pressure in a relatively closed cement environment, caused by gas or a liquid. The pressure may be controlled using hydrostatic force of a fluid to restrict or eliminate any influx into this environment.

[0060] The apparatus and process may also be used to control pressure in a cement annulus that has been caused by an ineffective cementing operation on the production casing string that has high inter-casing pressure (e.g. which is considered unsafe to run completion operations to bring the well online and produce oil and gas from the well).

[0061] The apparatus may be configured to switch between the dynamic pressurizing unit and the passive pressurizing unit based on the monitored pressure.

[0062] The dynamic pressurizing unit may be releasably attached to the apparatus. For example, when the passive pressurizing unit is being used to inject brine, the dynamic pressurizing unit may be removed.

[0063] The passive pressurizing unit may be releasably attached to the apparatus. This may allow the passive pressurizing unit to be replaced when one passive pressurizing unit is exhausted. The compression reservoir may be releasably attached to the passive pressurizing unit to enable replacement.

[0064] The apparatus may comprise multiple passive pressurizing units.

[0065] The injection brine or fluid may be filtered to less than 2 microns to allow it to easily flow down micro-fissures in the cement. The micro-fissures may have been created over time in the cement column or as a result of:

- Poor initial cementing operations
- Thermal shocks to well
- Pressure fluctuations caused by starting and stopping well production.
- Repeated pressure builds and bleed downs in such operations as well fracturing and the like.

- Continued erosion caused by repeated bleed down operations to reduce inter-casing pressure (or sustained casing pressure) on the well.

[0066] The injection brine or fluid may be non-corrosive, non-toxic and suitable for high pressure (e.g. up to 6,000psi) and/or high-temperature (e.g. up to 150°C) environments.

[0067] The fluid injection brine or fluid may be pumped and injected at low flow rates, (e.g. below 15 litres/hour). This may help prevent any material bridging or packing off in (e.g. blocking) the annulus flow path. This may help ensure that the brine can penetrate more fully into any fissures in the annulus cement.

[0068] The present process may not require any mechanical intervention in the annulus or well.

[0069] The present process may operate in parallel with well production.

[0070] The present process may reduce annulus pressure induced by high temperatures within the annulus (if present).

[0071] The present process may be considered to use the application of hydrostatic pressure being generated by the heavy cesium formate brine as it is drawn into the well caused by the effects of gravity.

[0072] The present process may be configured to use a remote automatic slow fluid feed system on the wellhead to continuously inject a heavy cesium formate brine solution into the cement annulus on an oil and gas well over an extended period of time.

[0073] An extended period of time may be 2 days or greater.

[0074] The ability to inject fluid into the cement annulus at a controlled slow rate (e.g. less than 15 litres/hour) may reduce or eliminate the potential for blockages to be created in the cement micro annulus voids and slowly allow the pressure to be increased over a long period of time.

[0075] The apparatus may be configured to monitor pressure on all pressure points in the system with electronic gauges and read and record the stored pressures as required directly from the unit's sensors into a portable device even when in a zone 1 division 1 ambient environment (e.g. a location where the hazardous atmosphere is expected to be present during normal operations on a continuous, intermittent or periodic basis). Once data has been downloaded it can be organized into a graph style presentation to effectively show treatment progress in relationship to flow and pressure into cement annulus.

[0076] Treatment time and pressure records may be monitored to confirm pressure control of annulus pressure(s) on wells over an extended time periods and/or for the commercial lifetime of the well. Well pressure data may be used by government regulators and authorities to show the wells are being operated within acceptable pressure limits.

[0077] The apparatus may be configured to transmit data to a remote computer to provide a remote indication of annular pressure re-occurrence.

[0078] The fracture gradient may be considered to be the factor used to determine formation fracturing pressure as a function of well depth in units of psi/ft. The fracture gradient in units of psi per foot is the fracture pressure in psi divided by the vertical depth of the fracture below the rig floor in feet.

[0079] A casing assembly may comprise a series of concentric casings. Typically, the casings which are towards the centre of the wellbore are longer and penetrate further into the ground from the surface than casings which are further away from the centre. A casing string is a pipe which is run into the wellbore and which is typically cemented in place. A casing assembly may comprise one or more of:

[0080] a production casing which may be cemented to stop oil migrating to thief zones and to prevent formation degradation which may cause loss in productivity. The production casing may be the longest and smallest-diameter casing.

[0081] an intermediate casing which may be configured to isolate formations. There may be several intermediate casing strings. The intermediate casing may be shorter and wider than the production casing.

[0082] a surface casing. The surface casing may be shorter and wider than the intermediate casing and/or the production casing.

[0083] a conductor casing which may be configured to prevent drilling fluids circulating outside the casing, causing surface erosion. The conductor casing may be shorter and wider than the surface casing, the intermediate casing and/or the production casing

[0084] The regions between the concentric casings form annuli which are filled with cement.

[0085] In the context of oil and gas, and this disclosure, a Christmas tree may be considered to be an assembly of valves, spools, pressure gauges and chokes fitted to the wellhead of a completed well to control production

[0086] A casing bowl may be considered to be a wellhead component, or a profile formed in wellhead equipment in which the casing hanger is located when a casing string has been installed. The casing bowl incorporates features to secure and seal the upper end of the casing string and frequently provides a port to enable communication with the annulus.

[0087] A casing shoe may be considered to be the bottom of the casing string, including the cement around it, or the equipment run at the bottom of the casing string.

[0088] Cesium formate is a neutral to slightly alkaline salt of cesium hydroxide and formic acid having the formula HCOO^-Cs^+ . It is extremely soluble in water. An 82 wt.% cesium formate solution has a density of 2.4 g/cm^3 . It has shown favorable health, safety and environmental (HSE) characteristics in laboratory tests and has applications as a drill-in, completion or workover fluid. Cesium formate may be mixed with less expensive potassium formate to make clear brine mixtures with a density range from 1.6 to 2.4 g/cm^3 . Formates have temperature stability up to around 190°C , depending on the duration of exposure to such a temperature.

[0089] A brine is a high-concentration solution of salt in water. Cesium formate brine may be an aqueous solution of Cesium formate salt.

BRIEF DESCRIPTION OF THE DRAWINGS

[0090] Various objects, features and advantages of the invention will be apparent from the following description of particular embodiments of the invention, as illustrated in the accompanying drawings. The drawings are not necessarily to scale, emphasis instead being placed upon illustrating the principles of various embodiments of the invention. Similar reference numerals indicate similar components.

Figure 1 is a schematic of the entire brine injection apparatus according to the present disclosure.

Figure 2 is a schematic of a dynamic pressurizing unit which is a Pressure Assisted Displacement Treatment System (PADTS).

Figure 3a is a schematic side-view of a passive pressurizing unit which is an Accumulator Containment Unit (ACU).

Figure 3b is a schematic top-view of a gauge manifold which is part of the passive pressurizing unit of figure 3a.

Figure 3c is a schematic side-view of a pressure flow regulating assembly which is used in conjunction with the passive pressurizing unit of figure 3a.

Figure 4 is a side view of the wellhead assembly.

Figure 5 is a schematic top-view of the connectors to the wellhead assembly.

Figure 6 is a flow diagram of the method of inject brine comprising cesium formate into a cement annulus according to the present disclosure.

DETAILED DESCRIPTION

Introduction to Present Technology

[0091] The present disclosure describes using a dynamic bleed and lube process that will use hydraulic pressure to continuously, gently and automatically inject a high-density cesium formate brine solution into the cement sheath within an inter-casing annulus. The fluid can flow into small fissures in the cement sheath displacing fluids (e.g. liquid and/or gases) as it flows. Once the fissures are filled with brine, further influx of fluids may be prevented. This may help increase the hydrostatic force in the well bore, stop the continued influx of oil and gas into the cement annulus and/or buffer the corrosive nature of H₂S and CO₂ present in the cement sheath.

[0092] The present process uses a monovalent heavy cesium formate brine to create hydrostatic pressure in the cement annulus which will reduce the influx of fluids into the cement annulus from below and after a period of time reach a balance point which will, over time result in a substantial reduction of previously recorded pressure.

[0093] The use of a non-toxic and environmentally benign cesium formate heavy brine coupled with the ability to closely control the method in which it is introduced to a well exhibiting dangerous signs of pressure residing in the cement between to strings of casing in an oil & gas well requires careful monitoring and treatment to greatly reduce chances of an accidental release of oil & gas to the environment.

Previous Technology

Perforation and Cement Squeeze

[0094] In order to repair an ineffective cementing operation, one previous solution was to perforate the production casing and squeeze a thin viscosity cement into the cement sheath with the noted inter-casing pressure (ICP) or surface casing pressure (SCP).

[0095] To do this, the well must be taken offline, and production stopped for an extended period of time. It is also necessary to pour a brine kill fluid into the well to counteract the pressure at the bottom of the well and then remove all equipment from the well with a service rig so that perforating and cement squeeze operations can proceed.

[0096] Perforating the production casing may result in a loss of well bore integrity as the production casing is the primary structure in the well bore. Once the casing is perforated the it may be necessary to apply a steel sheath on the inside of the casing to restore well bore integrity. However, the costs of this type of remedial action can render this process unfeasible.

[0097] If the original cement sheath developed micro-annuluses over time due to temperature and pressure fluctuations, the same issues may reoccur.

[0098] Any cement slurry is a multi-valent mix that may mix with any remaining particulate matter in the cement sheath which will severely restrict its movement inside the cement sheath.

[0099] Costs associated with this type of operation most often run into the hundreds of thousands of dollars and in some cases can run into millions of dollars depending on the complexity of the well design and location of the well.

[0100] Historically the results of conducting this type of operation have only had a low success rate.

Cement Injection via Wellhead Valve

[0101] Another option was the injection of a light-weight low viscosity cement slurry directly into the cement sheath annulus on the wellhead valve directly corresponding to the specific annulus.

[0102] While conducting this type of treatment there is no need to shut down production from the well.

[0103] However, the cement is multi-valent and will mix with any residual fluid or particulate matter present in the cement sheath which will restrict the depth this solution will be able to react in the cement sheath.

[0104] Most often the fluid being injected does not reach very far into the cement sheath and, will only result in a surface plug which masks the issue rather than solve the problem.

[0105] In many cases it has been noted that the problem quickly returns.

[0106] Because cement sets, if the injecting of cement does not cure the problem, it will greatly increase the difficulty level in further treating the well.

Polymer Injection

[0107] Another option was the injection of polymer type of fluids that will set up over time and block the pressure from the invading fluids and gases being shown on the surface gauges on the wellhead.

[0108] While conducting this type of treatment there is no need to shut down production from the well.

[0109] Like cement, polymers are multi-valent and will mix with any residual fluid or particulate matter present in the cement sheath which will restrict the depth this solution will be able to react in the cement sheath.

[0110] Most often the fluid being injected does not reach very far into the cement sheath and, will only result in a surface plug which again masks the issue rather than solve the problem.

[0111] In many cases it has been noted that the problem quickly returns.

[0112] If the injecting of this solution does not cure the problem, it will greatly increase the difficulty level in treating the well.

Zinc Formate brine

[0113] In the 1990's and early 2000 years, several oil companies tried to use a heavy zinc formate brine in a passive bleed and lube operation to try and increase the hydrostatic pressure in the cement sheath to control the influx of fluids and gases into the cement column.

[0114] This type of solution turned out to be problematic for several reasons and was abandoned.

[0115] The brine solution required the use of zinc bromide to achieve the required density to be effective in this type of application.

[0116] The brine solution containing zinc bromide was found very toxic to aquatic life with long lasting effects. Zinc bromide is an HSE risk to humans. Zinc Bromide solution may be harmful if swallowed; cause severe skin burns and eye damage; cause an allergic skin reaction; be toxic to aquatic life with long lasting effects; and be extremely corrosive to both metals and rubber products.

[0117] As with cement and polymer above the zinc solution is a multivalent chemical solution that may combine with fluid and particulate matter in the cement sheath which limits its ability to travel deep enough in the cement sheath to have a reasonable chance of being an effective treatment.

[0118] Various aspects of the invention will be described below with reference to the figures. For the purposes of illustration, components depicted in the figures are not necessarily drawn to scale. Instead, emphasis is placed on highlighting the various contributions of the components to the functionality of various aspects of the invention. A number of possible alternative features are introduced during the course of this description. It is to be understood that, according to the knowledge and judgment of persons skilled in the art, such alternative features may be substituted in various combinations to arrive at different embodiments of the present invention.

Pre-Injection Checks

[0119] Prior to initiating the process, an analysis of the well may be done to establish whether the well is a valid candidate for this treatment which will help the operator identify other potential problems if it is deemed not to be a candidate.

[0120] Each well may be individually assessed regardless of its proximity to other wells which may be under treatment process. During this process attempts must be made to try and identify the source of the influx.

[0121] The analysis may include:

- analyzing fluids and gases being vented from well to help in establishing where in the well the problem is being created;
- establishing volumes for fluids and gases being vented from the well along with time required to bleed well to a specific pressure and time it takes for pressure to return;
- establishing individual well components pressure limitations including using manufacturer certifications and government-mandated limitations;
- determining the fracture gradient of formation where casing shoe is set in the highest casing string in the cement annulus being treated; and/or
- determining the pressure limitations of casing strings present in the cement annulus being treated (Consideration may be made for both burst and collapse

and possible degradation of casing due to corrosive gases and fluids resident in the cement column).

[0122] Good candidate wells for this process may include one or more of the following:

- Wells which demonstrate extended bleed down times (30 minutes) with a rapid buildup of pressure (2 days to return to previous pressure noted) which indicates that there will be a reasonable clear path down the cement annulus. It must be noted that this “clear path” may only be 10 to 20 microns.
- Wells for which a proper evaluation has been done and source of zone where fluid influx is estimated to be from has been established so that it then gives us a pressure value to work with.
- Wells for which a path of influx has been established as to how fluid is entering the well.
- Wells for which the cement in the annulus to be treated is near the top of the well.

[0123] Poor Candidate Wells may include one or more of the following:

- Wells which have been treated previously by injecting a polymer sealant or thin cement slurry. By injecting this type of treatment into the annulus all that is usually accomplished is to plug up most pathways, at the top of the cement annulus, that we would need to convey our heavy cesium brine into the well. For these wells, the treatment time may be longer.
- Wells which can be bleed down very quickly (10 minutes) and have a very slow build up rate to reached previous pressure (1 month or more). This may indicate that there may not be clear pathways down to where the pressure is coming from.
- Wells for which there is evidence that there may be leak points in the casing of the annulus they wish to treat. These leaks will need to be corrected first then the process may be applied.
- Wells for which there are indications that wellhead valves are leaking. These must be remedied first then the process may be applied.
- Wells for which there is pressure on the inside of the production casing which could indicate a packer failure on the tubing string above the producing horizon.

Apparatus

[0124] The complete apparatus according to the present disclosure is configured to deliver brine under pressure to at least one inter-casing annulus and to remove gas and/or other fluid from the inter-casing annulus.

[0125] Figure 1 is a general schematic of the entire apparatus 100. The apparatus comprises several major components, in this case, including: a dynamic pressurizing unit 110; a passive pressurizing unit 120; a Primary Treatment Manifold (PTM) 140; and a wellhead connection assembly 170 which connects to the wellhead 150 via two valves 151 and 152, and which has a flare line 169.

Pressure Assisted Displacement Treatment System (PADTS)

[0126] As shown in figure 2, the apparatus comprises a dynamic pressurizing unit 210 which is a Pressure Assisted Displacement Treatment System (PADTS).

[0127] As shown in figure 2 (which is a more detailed version of a portion of figure 1), the dynamic pressurizing unit 210 comprises a pump 214 which, in this case, is an air pump for applying pressure (up to +4,500psi) to the brine to be injected into at least one annulus. By using a high-pressure air pump, better control of the injection rates and pressures while treating the well may be achieved. Therefore, an air pump is a preferred feature although mechanical pumps may be used in some circumstances.

[0128] The air pump 214 applies pressure to the brine from the reservoir via a hydraulic pressure intensifier 216. It will be appreciated that one-way valves may be used in the brine line to draw fluid in from the reservoir 201 (which may be unpressurized) and then allow pressure to be applied into either the inter-casing annulus or the passive pressurizing unit 220. The outlet pressure is calculated by the transmission ratio between air piston and plunger piston multiplied by the drive pressure. The static ultimate pressure and flow may be adjusted and controlled by the regulation of the air supply pressure. The brine solution is fed into the hydraulic pressure intensifier 216 under atmospheric pressure which is intensified gradually up to the required treatment pressure at a control rate.

[0129] The dynamic pressurizing unit 210 is configured to receive brine from a brine reservoir 201 for injection into at least one annulus and is configured to pressurize this brine in a controlled manner. It may also allow the pressure on the cement annulus to be

increased gradually to help limit the possibility of packing off due to residual matter left in the cement string.

[0130] In this case, a fluid return allows excess brine to be returned to the brine reservoir 201.

[0131] In this embodiment, the dynamic pressurizing unit 210 has two purposes in this operation:

- Initial slow buildup of fluid and pressure into the annulus to be treated until a predetermined pressure has been reached; and
- Charging the hydraulic accumulators via the ACU manifold (330 Figure 3a) to a predetermined pressure (e.g. 4,500psi) to continue treatment by slow feeding the well.

[0132] For the first purpose, the dynamic pressurizing unit 210 is configured to directly pump brine through the passive pressurizing unit manifold (330 Figure 3a) into the at least one annulus via the wellhead. That is, pressure delivered by the pump is applied to fluid which is moved directly into the at least one annulus.

[0133] For the second purpose, the dynamic pressurizing unit is configured to pressurize the brine into an accumulator of a passive pressurizing unit 220 which stores the brine under pressure. The brine can then be slowly released from the accumulator even when the dynamic pressurizing unit pump is not running. This may reduce energy consumption of the apparatus as it runs over an extended period of time (e.g. days, weeks or months).

[0134] When performing the slow build up of pressure in the annulus, the dynamic pressurizing unit 110, 210 is connected to the Primary Treatment Manifold 140, 240 by three lines: a high-pressure treatment line 113, 213; a pressure bleed line 112, 212 and an air purge line 211, 111. The air purge line has a valve 215.

[0135] The high-pressure treatment line 113, 213 is pressurized directly by the action of the air pump 110 acting on the brine in the dynamic pressurizing unit 110, 210. A pressure bleed line is configured to return fluid from the Primary Treatment Manifold back to the dynamic pressurizing unit. The return line may be used to minimize the potential loss of the treatment fluid as pressure must be released to allow for disconnect of any pressure lines. The air purge line 111, 211 may be used to vacate fluid from lines for preparation of moving the units between well sites to prevent any loss of treatment fluid.

[0136] The Primary Treatment Manifold 140, 240 is configured to connect to the wellhead connection assembly 170, 270 via a quick connector 242. A one-way valve is located in the feed line to prevent retrograde fluid flow from the wellhead connection assembly 170, 270 to the Primary Treatment Manifold 140, 240.

[0137] The dynamic pressurizing unit 110, 210 is configured to monitor pressures and flows using the electronic gauges (which may be intrinsically safe) while injection is in progress which allows for careful control during this operation and a record for review at any time after the job is complete. Gauges may each be independently set to monitor and record at different intervals.

[0138] Gauge data is easily and quickly downloaded by wireless transmission into an intrinsically safe tablet where data can be stored and easily transferred between users and computers as required.

[0139] All pressure hose connections used to transfer fluid or pressure are of a type which reduce any potential for accidental spillage, or loss of, the treatment fluid. The connections in this case are a high pressure (10,000psi rated) hydraulic quick couplings which may have a secondary seal which is engaged prior to the screw collar is tighten which release the flow pins and allows fluid to pass through the hoses. Once the screw collar is tightened the primary seal is engaged on the unit. Any hose containing treatment fluid makes use of this type of connection, regardless of size, to reduce the chance of accidental spillage.

[0140] The treatment lines, in this case, are equipped with multiple safety barriers such as one-way check valves and ball valves (all rated to a minimum of 6,000psi which is the pressure rating of all fluid hoses being used) to help ensure that fluids cannot escape from the wellhead into the environment or get back into, and damaging, either the dynamic pressurizing unit or passive pressurizing unit.

[0141] All connections and manifolds, in this embodiment, are made with grade 304 stainless steel (minimum) to help ensure safe use in possible H₂S environments.

Accumulator Containment Unit (ACU)

[0142] In this case, as shown in figure 3a-3c, the apparatus 100 also comprises a passive pressurizing unit 120, 220, 320 (or Accumulator Containment Unit - ACU) comprising a reservoir 321 configured to hold a volume of brine at an elevated pressure and a release valve 330 configured to deliver brine under pressure to the cement annulus between

concentric well casings. In this case, the passive pressurizing unit 120, 220, 320 forms part of the dynamic pressurizing unit 110, 210.

[0143] The passive pressurizing unit 320 comprises a compression reservoir 321 which is configured to receive pressurized flow 338 from the pump of the dynamic pressurizing unit to charge the reservoir 321. The pressure flow from the dynamic pressurizing unit is delivered via a hydraulic quick-release coupling 326. The pressure flow from the dynamic pressurizing unit is delivered to the compression reservoir via a fluid manifold 330, an isolation valve 323 and a compression reservoir connection assembly 322. Connected to the compression reservoir is a gauge manifold 329 to allow for a manual pressure gauge 329a, an electronic pressure gauge 329b and a nitrogen charge point 329c (see figure 3b). In this case, the bladder inside the accumulator is charged to a predetermined set value using nitrogen through connection point 329c. Once the internal bladder on the accumulator (321) bladder has been charged to the predetermined pressure the air pump in 110,210 is engaged and treatment fluid is pressured into the accumulator 321 until required fluid pressure has been achieved.

[0144] The system also comprises two pressure gauges connected to the fluid manifold: an electronic gauge 324 and a manual gauge 325.

[0145] In this embodiment, after the compression reservoir 321 has been pressurized, the isolation valve 323 is closed isolating the compression reservoir 321 from both the pump of the dynamic pressurizing unit and the inter-casing annulus.

[0146] Then brine 337 is actively pumped from the dynamic pressurizing unit into the annulus via a pressure flow regulating assembly 328 and a primary treatment manifold. This ramps up the pressure within the annulus slowly.

[0147] The pressure flow regulating assembly 328 is shown in figure 3c and comprises: a hydraulic coupling 331; a pressure regulator 332; a pressure gauge 333, a one-way check valve 334 and a second hydraulic coupling 335 for connection to the primary treatment manifold. In this way flow 337 is directed to the primary treatment manifold. The line between the hydraulic coupling 331 (which connects to the pressurizing units) and the wellhead connector may be considered to be the treatment line.

[0148] The one-way check valve is configured to prevent retrograde flow from the annulus back into either the passive or dynamic pressurizing units.

[0149] Once the pressure in the annulus has reached a predetermined threshold, the dynamic pressurizing unit is turned off and isolated from the pressure flow regulating assembly. The dynamic pressurizing unit isolation valve 323 is opened to allow regulated flow from the compression reservoir 321 into the inter-casing annulus.

Connection to Well

[0150] Figure 4 is a side view of the wellhead assembly 471. In this case, the well itself comprises a series of concentric tubes and casings. The production casing 486 is hung off the wellhead flange 490 (or Internal Production Casing Spool) and cemented. Within the production casing 486, there is tubing 485 which is hung of the top 491 of the wellhead (from a tubing hanger) and is configured to transport oil and/or gas from the well up into the Christmas Tree (an assembly of valves, spools, pressure gauges and/or chokes fitted to the wellhead of a completed well to control production). Outside the production casing, there is the wider and shorter intermediate casing 487 string which is suspended from a wellhead flange and cemented. Outside the intermediate casing is the even wider and even shorter surface casing 488 which is cemented into the well with a casing bowl attached.

[0151] Between each casing pair, there is an inter-casing annulus. In this case, there are two inter-casing annuli: the production-intermediate annulus between the production and intermediate casings; and the intermediate-surface annulus between the intermediate and surface casings.

[0152] The Christmas tree in this case comprises a lower master valve 492, an upper master valve 493, a swab valve 494, a wing valve 495 and a production choke 496 where production flow 497 is controlled. Other configurations may also be used.

[0153] As shown in figure 4, each brine injection valve 478, 489 is in fluid communication with a ring-shaped connector which facilitates injecting the brine into the respective annulus. There is also no fluid communication between the annuli and the production tubing (i.e. each annulus is isolated from the production tubing). This means that it is not necessary to seal off the central production casing or tubing while brine is being injected into one or more of the annuli.

[0154] In the present process heavy cesium brine is injected, under controlled conditions, into the cement within the production-intermediate annulus at a slow rate. Once the innermost annulus is treated (the production-intermediate annulus in this case), the brine

may then be injected into the next inner-most annulus (the intermediate surface annulus in this case). Note the annulus treatment sequence may be changed subject to the individual well characteristics dependent on observed pressures and well history.

[0155] As shown in figure 5, there are two configurations for the wellhead connection assembly. In each case, the wellhead 571 is connected to the pressurized fluid source 584 via a wellhead manifold 577. There is a one-way valve 583 (in this case a stainless steel ½-inch check valve) between the pressurized fluid source 584 and the wellhead manifold 577 to prevent retrograde flow. Between the wellhead 571 and the wellhead manifold 577 there are two valves 578, 579 (using two valves is an industry standard to allow for a failure of one valve). In addition, there is also an additional ball valve 560 (e.g. a stainless steel ½-inch ball valve) between 580 connector and wellhead manifold 577. Also connected to the wellhead manifold 577 are a flare line 569 and a pressure gauge line with pressure gauge 581. The pressure gauge line also includes a ball valve 561 (e.g. a ¼-inch stainless steel ball valve), a pressure bleed valve 562 (e.g. ¼-inch) and a hydraulic connector 563 (e.g. ¼-inch) for connecting to the pressure gauge 581. The gauge assembly may be electronic or conventional.

[0156] The flare line comprises a series of valves (including pressure bleed needle valve 572 and high-pressure ball valves 570 and 576) to allow the flare line to be opened and closed when fluid is to be extracted from the casing annulus and a visual flow monitor 573. In this embodiment, valve 572 may be used to enable samples to be obtained. Needle valve 572 can also be used to capture either gas or fluid samples into pressure bottles. As the fluid from the well is removed a user may be able to visually see what is coming from it which will allow the bleeding of the well to be controlled or stopped and the valve assembly reconfigured to capture fluid or gas samples as required for analysis (e.g. density or chemical analysis). An initial density check may be conducted onsite (with fluid density scale) and a further sample may be retained for laboratory analysis off site.

[0157] As shown in figure 5, these components are connected with quick release couplings 574, 575, 580, 582 in this case.

[0158] Figure 5 corresponds to the wellhead connection used for initial treatment (i.e. when pressure is being ramped up on the wellhead annulus) and bleed operations (i.e. when fluid is being removed from the annulus). In this embodiment, in these situations, the wellhead is connected to a flare line.

[0159] In the embodiment shown in figure 5, the connection to the well is via a single ½ inch line. This provides sufficiently large diameter to feed the treatment fluid into the well head when injecting into the cement annulus. In some wells, access to the annulus may be via two 9/16-inch autoclave fittings on the well head. Therefore, other embodiments may use multiple smaller diameter lines (e.g. two ¼ inch hoses). The multiple lines may be connected to a larger diameter line (e.g. ½ inch line) using a splitter which may be located between valve 577 and the wellhead connector.

[0160] The hoses being used to attached to the well head along with the valves (e.g. the three innermost valves) on the well head connection block are all rated to 10,000psi.

[0161] For the steady-state situation when there is a slow feed from, for example, the passive pressurizing unit, the flare line can be closed using valve 576 and the flare line removed at the connector 574. The flare line can be connected quickly if required.

Process

[0162] Once any background work is complete and well is deemed a candidate for this treatment process a Pressure Assisted Displacement Treatment System (PADTS) unit is connected to wellhead components using treatment lines with custom hose manifolds, bleed down manifolds, one-way safety valves and isolation valves.

[0163] One or more of the following steps may be carried out prior to initiating the injection of brine:

- Close treatment hose closest to wellhead, but before custom bleed assembly, and ensure hoses are full of fluid and ready to displace fluid into well.
- All hoses, valves and connections are pressure tested (e.g. to 6,000psi) while isolated from wellhead valves. These are recorded.
- Release pressure on unit and then pressure test against wellhead valves to their rated pressure. Bleed well down paying careful attention to both components and volume being bled along with time.

[0164] Then, treatment fluid is slowly injected into the cement annulus being treated and the pressure gradually comes up to the predetermined pressure determined by analysis that was done on the well. For example, on a well (each well will be different) all pressures, in this case, are read from the well head valves:

- Well has exhibited a casing pressure of 2,000psi
- Time to bleed well down to zero was 30 minutes

- Time for pressure to rebuild to 2,000psi was 48 hours.
- Connect treatment assembly and bleed well down to an agreed pressure through the attached bleed down assembly.
- Once agreed to bleed down pressure has been reached close bleed valves and begin slowly injecting the treatment fluid into the well annulus being treated
- Treatment pressure will be built up over 4 to 8 hours or more if required. Pump time may depend on well conditions.

[0165] In this case, the injection process comprises: injecting brine comprising cesium formate into a cement annulus between concentric well casings; and monitoring the pressure of the brine within the annulus; and controlling the flow rate of the brine being injected based on the monitored pressure.

[0166] In this ramping-up stage, the flow and pressure of the injected brine is controlled using an air pump. In other embodiments, the flow and pressure of the injected brine may be controlled by a plunger style pump (or another suitable pump). The choice of pump may depend on meet specific calculated well treatment needs, the safety requirements of the site and/or the site conditions.

[0167] In this case, the density of the brine is greater than 1.8g/ml. As noted above, the injected brine is monovalent which means that it does not bind easily to substances within the annulus, thereby allowing it to penetrate deeply into fissures in the cement. In this case, the brine is filtered than 2 microns prior to injection which may also help the brine penetrate into fissures without blocking them.

[0168] While the pressure is increasing, gas may be continuously or periodically vented from the cement annulus. That is, the process may comprise cycling between bleeding fluids from the annulus and injecting brine.

[0169] In this case, when liquid is bled from the annulus it is analyzed by measuring the density of the fluid being bled from the annulus. The apparatus is configured to allow stopping the bleeding when the density exceeds a predetermined threshold (e.g. 1.25sg) as this may indicative that the injection fluid is being removed from the annulus. In other embodiments, the chemical composition of the liquid and/or gas may be analyzed. This can indicate when injection fluid being removed from the annulus.

[0170] As noted above, production from the well can continues during the brine injection.

[0171] When the predetermined pressure is reached, injection of the brine switches from a first injecting apparatus (e.g. the dynamic pressurizing unit) to a second injecting apparatus (e.g. the passive pressurizing unit). The second injecting apparatus is configured to maintain a steady-state predetermined pressure on the annulus.

[0172] During this stage the brine is injected at less than 40 litres/hour (e.g. and/or less than 15 litres/hour).

[0173] When the predetermined pressure is reached, the dynamic pressurizing unit being used to treat the well may be disconnected from the passive pressurizing unit, while the passive pressurizing unit still injects fluid into the well as the treatment fluid drops in the annulus. The dynamic pressurizing unit may then be removed.

[0174] The pressure on the wellhead may be electronically monitored continuously while the passive pressurizing unit is feeding the well.

[0175] While the passive pressurizing unit being used to slow feed the well if the stored hydraulic energy (accumulator pressure) reduces to a point where the bottle pressure approaches that of the treatment pressure the passive pressurizing unit's will be recharged by the dynamic pressurizing unit (or an exchange of another passive pressurizing unit with a full fluid reservoir under pressure).

[0176] If the passive pressurizing unit stops transferring fluid for an extended period of time, the apparatus may be configured to stop injection and the passive pressurizing unit may be disconnected from the wellhead. Before removing the pressurizing unit, the treatment line may be sealed when the monitored pressure reaches a steady state without further injections of brine.

[0177] Pressure can continue to be monitored and pressures recorded for an extended period of time even after removal of the pressurizing units.

[0178] After a period of time to allow the fluid to fall in the cement annulus the "Bleed & Lube" cycle is continued with a controlled annulus pressure bleed off. To ensure that what is being ejected on surface is not the treatment fluid, the removed fluid is analyzed (e.g. by density or chemically). For example, if bleed fluid has a density higher than 1.25sg bleeding is to be stopped and more time is given to the well to allow the treatment fluid to fall in the well.

[0179] The Bleed & Lube cycle may be repeated as needed by well response and the treatment stops when the well pressures are reduced to zero or below a predetermined acceptable safe level.

[0180] At all stages throughout the treatment and following the treatment the well pressures are continually monitored and recorded.

[0181] Installation post treatment of electronic pressure data units will allow periodic bleed down of annulus pressure and flow back monitoring and allowing the well to receive a further Bleed & Lube cycles as necessary.

Other Options

[0182] The dynamic pressurizing unit shell and passive pressurizing unit shell may be formed of extruded fiberglass construction materials to reduce weight and eliminate corrosion from the elements.

[0183] The system may comprise intrinsically safe and battery-powered communications system to upload data from the units to the cloud from remote locations and back to computers in any office worldwide.

[0184] The system may be configured to provide automatic alerts to predetermined personnel (through a communications system) when key pressure points are reached. The system may be configured to provide remote operation and control (through a communications system) e.g. by predetermined personnel.

[0185] The system may comprise remote shut down valves that can be activated from a central facility through the cloud when wells are on automatic feed if remote monitoring indicates a problem.

[0186] The system may be configured to provide long-term pressure monitoring, e.g. via a cloud communication system. The system may be configured to provide to provide remote operation and control of a series of wells with single or multiple pressurizing units installed for long term (e.g. months or years) SAP (Systems Applications and Products) control via a cloud communication system or another electronic communication system.

[0187] The system may comprise a unit (e.g. which may be mobile) to create cesium formate making use of several new available technologies and using carbon capture as feed stock to create the formic acid to be used in the creation of the cesium formate fluid in local markets to enhance the local content of our operations. This unit may also be used to refurbish cesium formate recovered from a well.

[0188] In extreme cold the system may comprise a heater that will maintain treatment line temperatures above -10°C to prevent crystallization of the fluid being injected into the well bore. Cesium formate is often used in high temperature and high-pressure wells as a completion fluid due to its stability in this type of environments.

[0189] In the case of treating multiple wellhead annuli on the same offshore platform the passive pressurizing units would remain attached to the dynamic pressurizing unit. If it is required to treat multiple wellheads on different platforms offshore, we would treat the first wellheads on a platform and once a suitable slow feed rate has been achieved the dynamic pressurizing unit would be removed leaving the passive pressurizing unit or units on that well. The dynamic pressurizing unit could be moved with the remaining attached passive pressurizing units to the next platform that has a well that requires treatment. Each dynamic pressurizing unit may be configured to accommodate multiple (up to five or more) passive pressurizing units. If, during the slow injection treatment using the passive pressurizing unit, it is required to be recharged it is possible to take a full passive pressurizing unit to the required platform and swap it out for the depleted passive pressurizing unit which will then be returned to the dynamic pressurizing unit to be recharged as needed.

[0190] In an onshore treatment operation when multiple wells are treated in a field, the same type of operation can be conducted as noted above in the offshore operations. In the onshore operation, the dynamic pressurizing unit may be more mobile so it can easily move between wells being treated to recharge passive pressurizing units as required.

[0191] Although the present invention has been described and illustrated with respect to preferred embodiments and preferred uses thereof, it is not to be so limited since modifications and changes can be made therein which are within the full, intended scope of the invention as understood by those skilled in the art.

CLAIMS

1. A process comprising:
injecting brine comprising cesium formate into a cement annulus between concentric well casings;
monitoring the pressure of the brine within the annulus; and
controlling the flow rate of the brine being injected based on the monitored pressure.
2. The process of claim 1, wherein the density of the brine is greater than 1.8g/ml.
3. The process according to any one of claims 1-2, wherein the flow and pressure of the injected brine is controlled using an air pump.
4. The process according to any one of claims 1-3, wherein the flow and pressure of the injected brine is controlled using a pressure intensifier.
5. The process according to any one of claims 1-4, wherein the brine is injected using a treatment line, wherein the treatment line includes at least one one-way check valve to prevent fluids escaping from the annulus via the treatment line.
6. The process according to any one of claims 1-5, wherein the process comprises ramping up the pressure of the brine within the annulus to an initial predetermined pressure over the course of between four hours to five days.
7. The process according to any one of claims 1-6, wherein the process comprises venting gas from the cement annulus.
8. The process according to any one of claims 1-7, wherein the process comprises cycling between bleeding fluids from the annulus and injecting brine.
9. The process according to any one of claims 1-8, wherein the process comprises:
measuring the density of the fluid being bled from the annulus; stopping the bleeding when the density exceeds a predetermined threshold.
10. The process according to any one of claims 1-9, wherein the process comprises:
injecting the brine into the cement annulus to reach an initial predetermined pressure using a first injecting apparatus; and
once the initial predetermined pressure is reached, injecting the brine into the cement annulus to maintain a steady-state predetermined pressure using a second injecting apparatus.

11. The process according to any one of claims 1-10, wherein the injected brine is monovalent.
12. The process according to any one of claims 1-11, wherein the process comprises filtering the brine to less than 2 microns prior to injection.
13. The process according to any one of claims 1-12, wherein the brine is injected at less than 40 litres/hour.
14. The process according to any one of claims 1-13, wherein production from the well continues during the brine injection.
15. The process according to any one of claims 1-14, wherein the process comprises, prior to injecting the brine:
measuring the pressure in the annulus; removing fluid from the annulus until a predetermined pressure is reached; and determining the rate of increase of pressure; and controlling the rate of brine based on the determined rate of increase of pressure.
16. The process according to any one of claims 1-15, wherein the brine is injected using a treatment line; and the process comprises sealing the treatment line when the monitored pressure reaches a steady state without further injections of brine.
17. The process according to any one of claims 1-16, wherein the brine is injected using a treatment line, and the process comprises monitoring the temperature of the treatment line and heating the treatment line when the treatment-line temperature falls below a predetermined threshold.
18. An apparatus comprising:
an annulus connector configured to connect to a cement annulus between concentric well casings;
a pressurizing unit configured to inject brine under pressure into the cement annulus between concentric well casings via the annulus connector; and
a pressure monitor configured to monitor the pressure of the brine within the annulus; and
a controller configured to control the pump to control the flow rate of the brine being injected based on the monitored pressure.
19. The apparatus of claim 18, wherein the pressurizing unit comprises:
a dynamic pressurizing unit comprising a pump configured to apply pressure to the brine; and

a passive pressurizing unit comprising a compression reservoir configured to hold a volume of brine at an elevated pressure and a passive-pressurizing-unit release valve configured to deliver brine under pressure to the cement annulus between concentric well casings.

20. The apparatus according to claim 19, wherein the dynamic pressurizing unit is configured to elevate the pressure within the passive pressurizing unit reservoir.

21. The apparatus according to any one of claims 19-20, wherein the dynamic pressurizing unit is configured to enable delivery of brine under pressure directly to the cement annulus between concentric well casings.

22. The apparatus according to any one of claims 19-21, wherein the dynamic pressurizing unit comprises air pump configured to pressurize the brine.

23. The apparatus according to any one of claims 19-22, wherein the dynamic pressurizing unit comprises a hydraulic intensifier configured to intensify the pressure applied by the pump on the brine.

24. The apparatus according to any one of claims 19-23, wherein the apparatus is configured to switch between the dynamic pressurizing unit and the passive pressurizing unit based on the monitored pressure and flow.

25. The apparatus according to any one of claims 19-24, wherein the dynamic pressurizing unit is releasably attached to the apparatus.

26. The apparatus according to any one of claims 19-25, wherein the passive pressurizing unit is releasably attached to the apparatus.

27. The apparatus according to any one of claims 19-26, wherein the apparatus comprises multiple passive pressurizing units.

28. The apparatus according to any one of claims 18-27, wherein the apparatus is configured to ramp up the pressure of the brine within the annulus to a predetermined value and then to maintain that pressure.

29. The apparatus according to any one of claims 18-28, wherein the apparatus comprises a treatment line between the pressurizing units and the cement annulus, the treatment line having one or more one-way valves configured to prevent retrograde flow from the cement annulus.

30. The apparatus according to any one of claims 18-29, wherein the apparatus comprises a treatment line between the pressurizing units and the cement annulus, the treatment line having one or more pressure regulators.
31. The apparatus according to any one of claims 18-30, wherein the apparatus comprises a flare line for allowing removal of fluid from the annulus.
32. The apparatus according to any one of claims 18-31, wherein the apparatus comprises one or more bleed valves for allowing removal of fluid from the annulus.
33. The apparatus according to any one of claims 18-32, wherein the apparatus comprises one or more pressure gauges on, or adjacent to, the annulus connector for monitoring the pressure of the brine within the annulus.
34. The apparatus according to any one of claims 18-33, wherein the apparatus comprises a temperature sensor and a heater for heating injected brine, wherein the controller is configured to control the heater to maintain the injected brine at temperatures above a predetermined temperature.
35. A process comprising:
injecting brine comprising cesium formate into a cement annulus between concentric well casings.

Figure 1

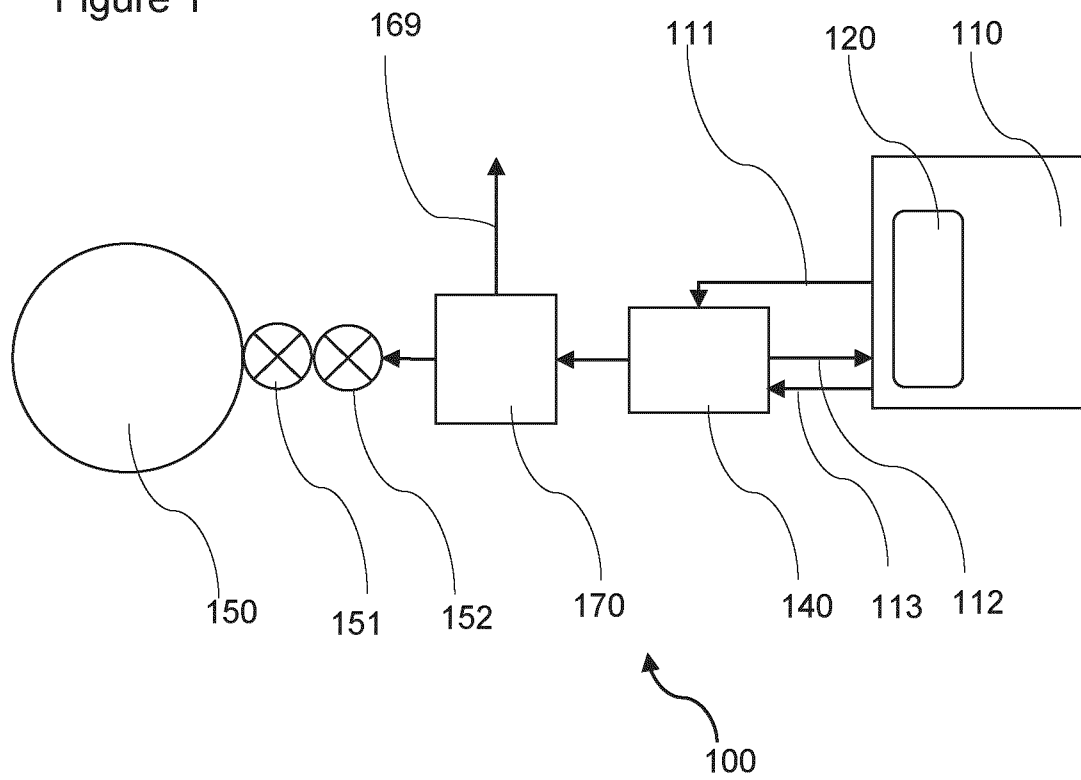


Figure 2

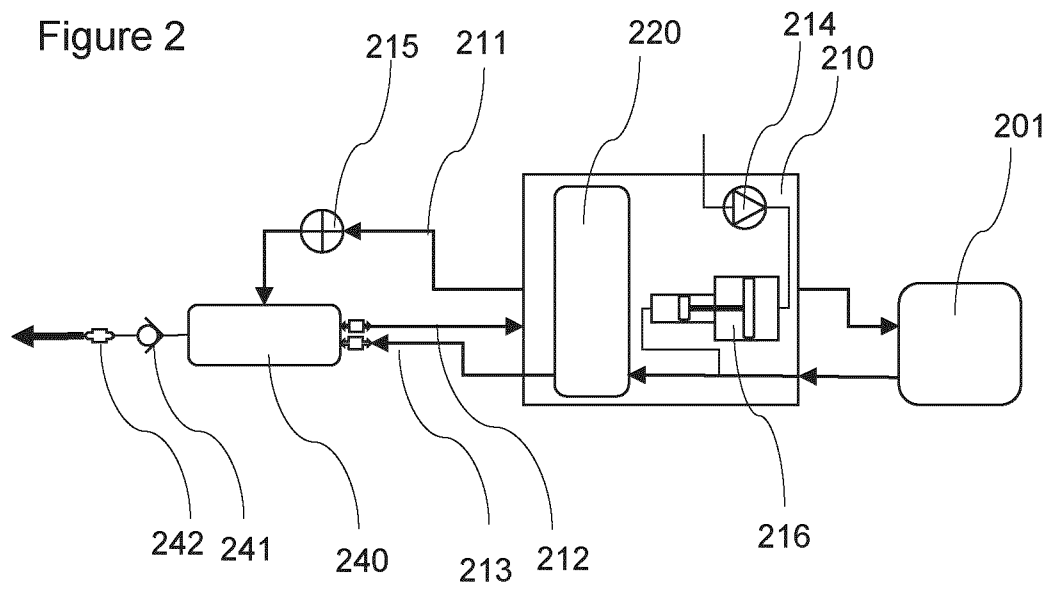


Figure 3a

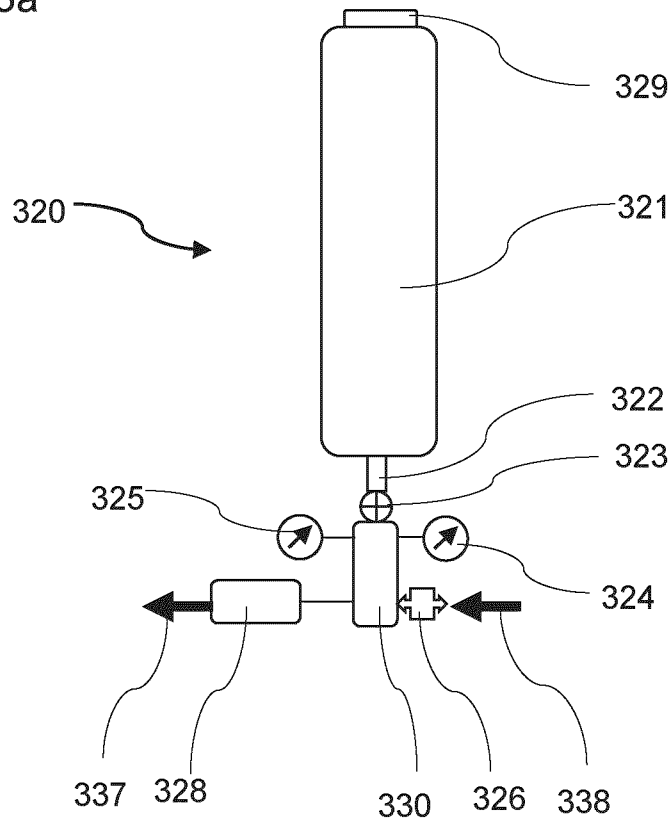


Figure 3b

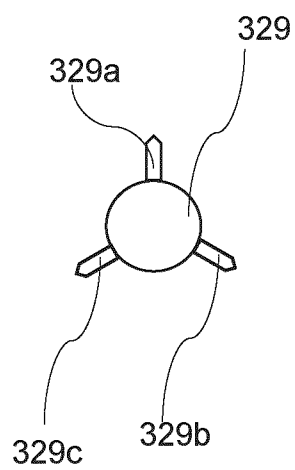
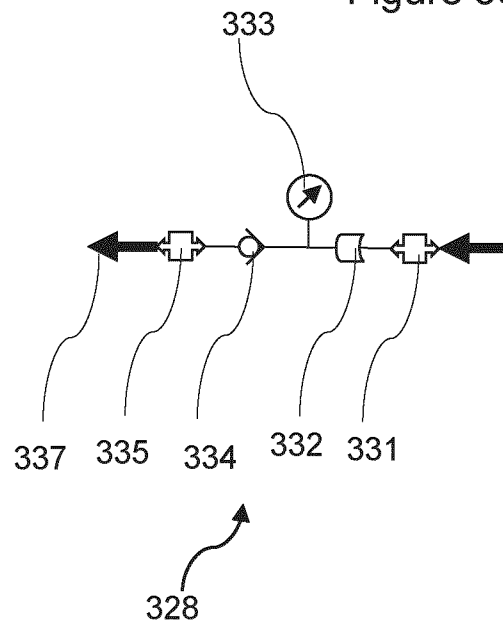


Figure 3c



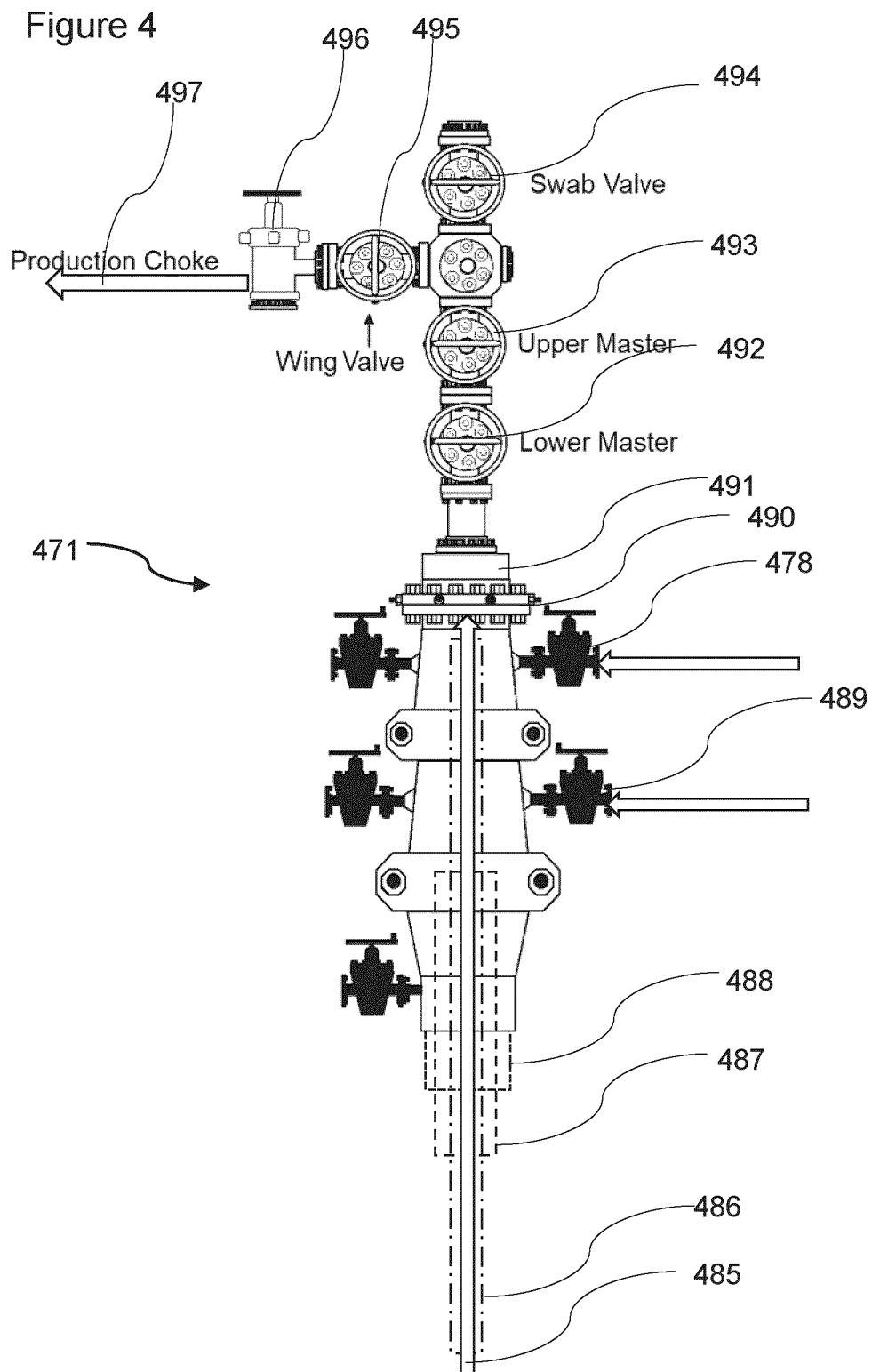


Figure 5

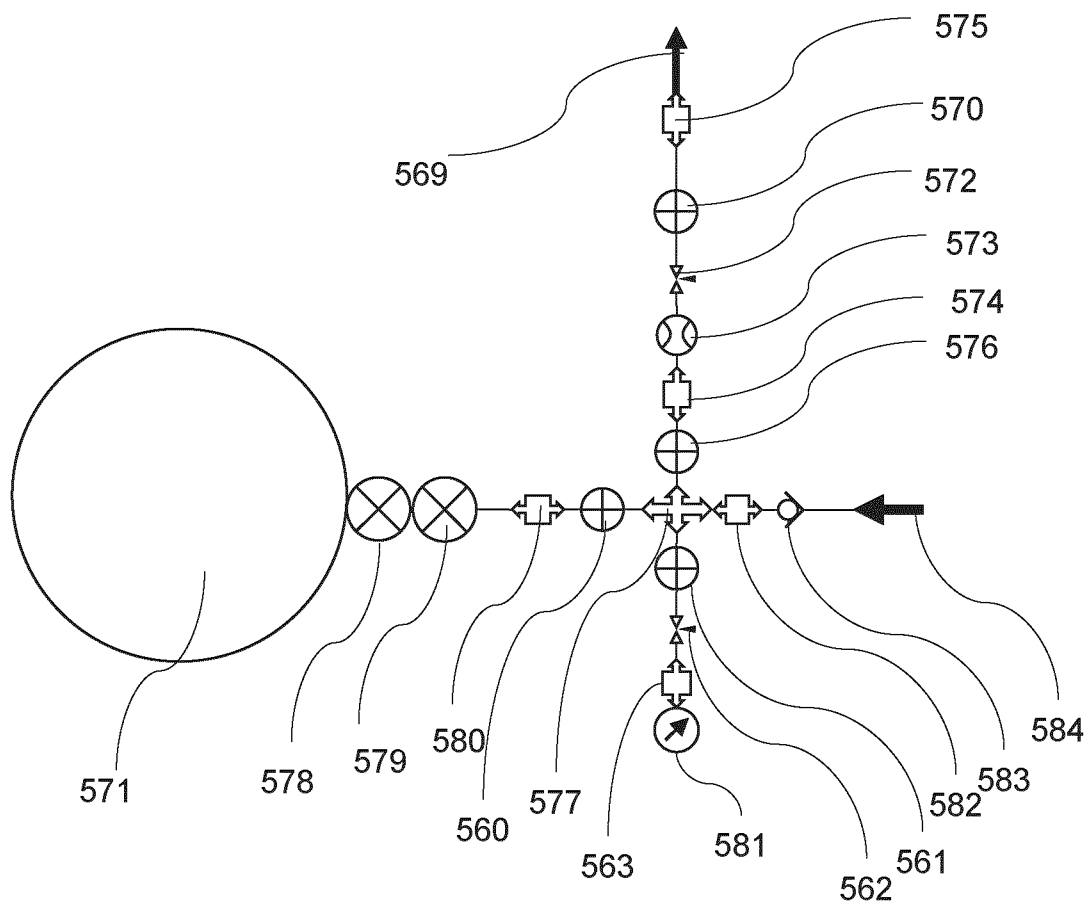


Figure 6

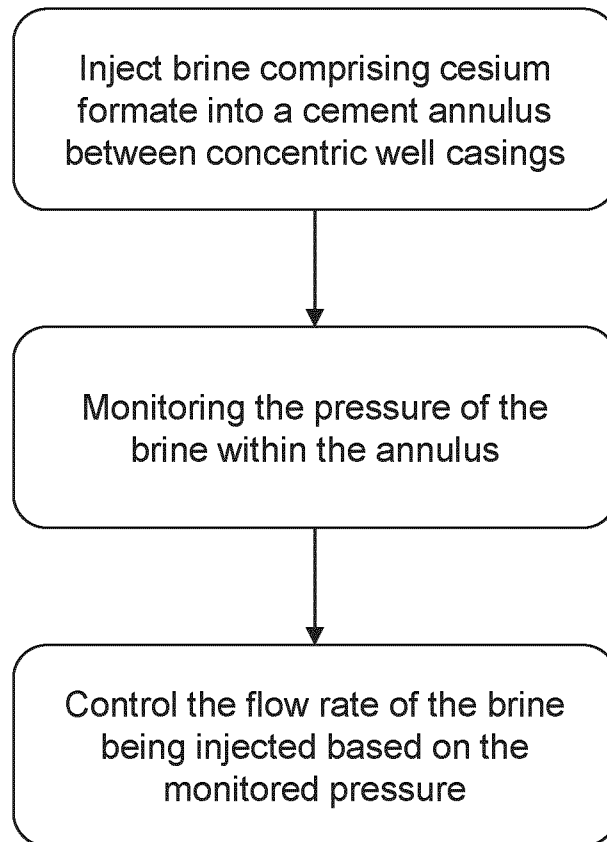


Figure 6

