



(51) International Patent Classification:

E21B 43/34 (2006.01) *G01F 23/22* (2006.01)
E21B 47/10 (2012.01)

(21) International Application Number:

PCT/US2020/070601

(22) International Filing Date:

30 September 2020 (30.09.2020)

(25) Filing Language:

English

(26) Publication Language:

English

(30) Priority Data:

62/907,859 30 September 2019 (30.09.2019) US

(71) Applicant (for US only): **SCHLUMBERGER TECHNOLOGY CORPORATION** [US/US]; 300 Schlumberger Drive, Sugar Land, Texas 77478 (US).

(71) Applicant (for CA only): **SCHLUMBERGER CANADA LIMITED** [CA/CA]; 125 – 9 Avenue SE, Calgary, Alberta T2G 0P6 (CA).

(71) Applicant (for FR only): **SERVICES PETROLIERS SCHLUMBERGER** [FR/FR]; 42 rue Saint Dominique, 75007 Paris (FR).

(71) Applicant (for all designated States except CA, FR, US): **SCHLUMBERGER TECHNOLOGY B.V.** [NL/NL]; Parkstraat 83, 2514 JG The Hague (NL).

(72) Inventors: **POTAPENKO, Dmitriy**; 3310 Vista Lake Drive, Sugar Land, Texas 77478 (US). **SELL, Brent**; 3026 Nottingham Drive, Shreveport, Louisiana 71115 (US). **WILSON, Joseph**; 5300 W Sam Houston Pkwy N, Houston, Texas 77041 (US).

(74) Agent: **SNEDDON, Cameron, R.** et al.; Schlumberger, 10001 Richmond Avenue, Room 4720, Houston, Texas 77042 (US).

(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, IT, JO, JP, KE, KG, KH, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD,

(54) Title: METHOD AND APPARATUS FOR MEASURING COMPONENTS OF MULTIPHASE FLUID DURING WELL FLOWBACK OPERATION

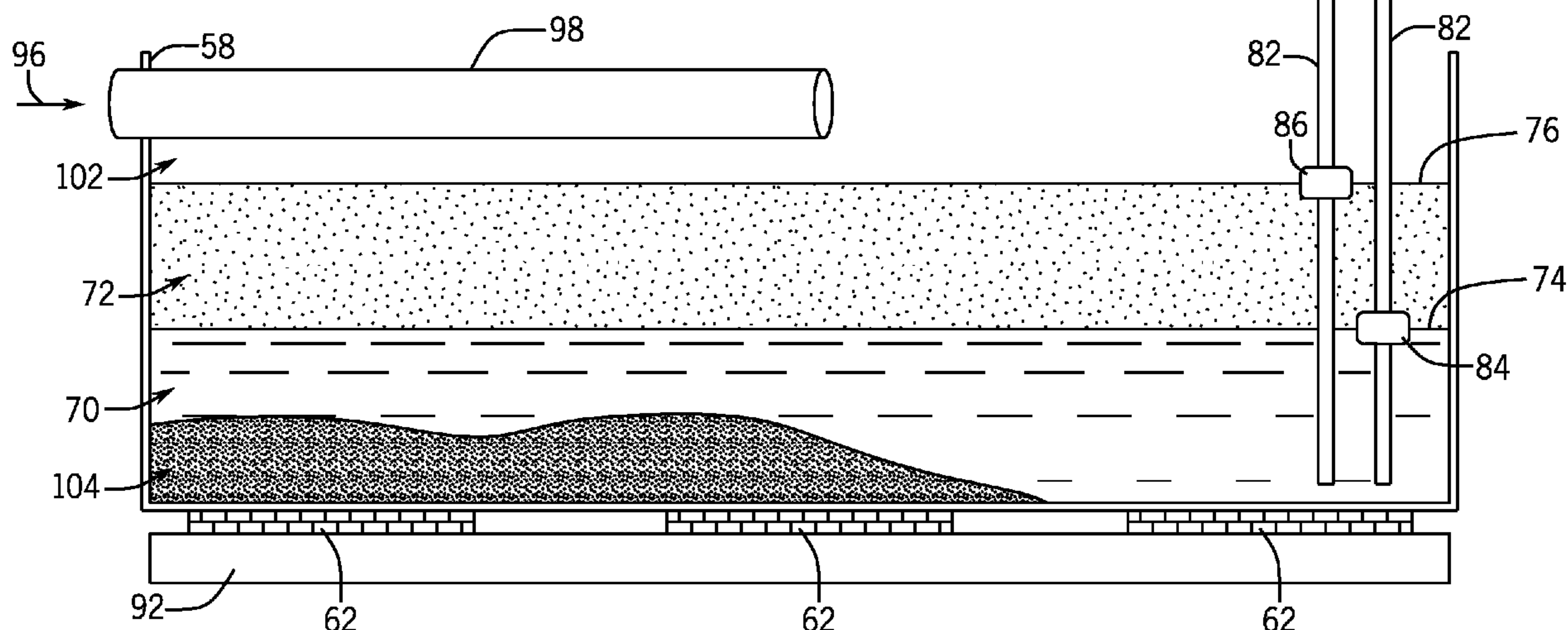


FIG. 6

(57) Abstract: Systems and methods for measuring components of a multiphase fluid, such as flowback fluid during a well flowback operation, are provided. In one embodiment, an apparatus includes a tank to receive a multiphase fluid having solids and multiple fluid phases from a well. The apparatus also includes a load cell positioned below the tank and a fluid level sensor to measure a fluid level within the tank. Further, the apparatus includes a data analyzer to determine, based on data acquired via the load cell and the fluid level sensor, a volume or mass of the solids of the multiphase fluid received in the tank and individual phase volumes or masses of multiple fluid phases of the multiphase fluid received in the tank. Additional systems, devices, and methods are also disclosed.



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, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, WS, 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:

- *without international search report and to be republished upon receipt of that report (Rule 48.2(g))*

METHOD AND APPARATUS FOR MEASURING COMPONENTS OF MULTIPHASE FLUID DURING WELL FLOWBACK OPERATION

CROSS-REFERENCE TO RELATED APPLICATION

[0001] This application claims priority to U.S. Provisional Application Serial No.: 62/907,859 filed 30 September 2019, which is herein incorporated by reference.

BACKGROUND

[0002] This disclosure relates to gas or oil well testing or production monitoring and, more particularly, some embodiments relate to methods and apparatuses for analyzing multiphase fluids produced from gas or oil wells during flowback operations.

Description of the Related Art

[0003] In order to meet consumer and industrial demand for natural resources, companies often invest substantial amounts of time and money in finding and extracting oil, natural gas, and other subterranean resources. Particularly, once a desired subterranean resource is discovered, drilling and production systems are often employed to access and extract the resource. These systems may be located onshore or offshore depending on the location of a desired resource. Further, such systems generally include a wellhead assembly through which the resource is extracted.

[0004] In some instances, such wellhead assemblies may use a fracturing tree and other components to facilitate a fracturing process and stimulate production from a well. As will be appreciated, resources such as oil and natural gas are generally extracted from fissures or other cavities formed in various subterranean rock formations or strata. To facilitate extraction of such resources, a well may be subjected to a fracturing process that creates one or more man-made fractures in a rock formation. This facilitates, for example, coupling of pre-existing fissures and cavities, allowing oil, gas, or the like to flow into the wellbore. Such fracturing processes typically include injecting a fracturing fluid—often a mixture or slurry including sand and water—into the well to increase the well's pressure and form the man-made fractures.

[0005] Fracturing fluid often includes water (or another liquid) mixed with sand or some other proppants. The fracturing fluid is pumped down a well into a formation to extend fractures and fill them with the proppants, which operate to hold open the fractures after pumping has stopped to allow formation fluids to be more easily produced via the well. Following pumping of fracturing fluid into a well, fluid can be produced from the well during a flowback operation. The fluid produced from the well can include fracturing fluid, other fluids (e.g., formation fluids and drilling fluids), and solid particulates (e.g., sand).

SUMMARY

[0006] Certain aspects of some embodiments disclosed herein are set forth below. It should be understood that these aspects are presented merely to provide the reader with a brief summary of certain forms the invention might take and that these aspects are not intended to limit the scope of the invention. Indeed, the invention may encompass a variety of aspects that may not be set forth below.

[0007] In one embodiment of the present disclosure, an apparatus includes a tank for receiving a multiphase fluid that includes solids and multiple fluid phases from a well. The apparatus also includes a load cell positioned below the tank and a fluid level sensor positioned to measure a fluid level in the tank. Further, the apparatus includes a processor-based data analyzer to determine, based on data acquired via the load cell and the fluid level sensor, a volume or mass of the solids of the multiphase fluid received in the tank and individual phase volumes or masses of two or more of the multiple fluid phases of the multiphase fluid received in the tank.

[0008] In another embodiment, an apparatus includes a tank for receiving a fluid including solid particulates from a well. The apparatus also includes a load cell below the tank and a processor-based data analyzer. Based on a weight of the tank measured via the load cell, the data analyzer determines a volume or mass of the solid particulates received in the tank in real-time as the fluid flows into the tank.

[0009] In an additional embodiment, a method includes receiving a multiphase fluid from a well into a flowback tank during a flowback operation. The multiphase fluid includes a water phase, a liquid hydrocarbon phase, and entrained sand. Further, the

method includes measuring densities of the water phase, the liquid hydrocarbon phase, and the sand, and measuring a weight of the flowback tank during the flowback operation. The method also includes determining lower and upper boundaries of the liquid hydrocarbon phase within the flowback tank. Additionally, the method includes calculating mass or volume of the sand received in the flowback tank with the multiphase fluid based on the measured densities of the water phase, the liquid hydrocarbon phase, and the sand, on the weight of the flowback tank measured during the flowback operation, and on the determined lower and upper boundaries of the liquid hydrocarbon phase within the flowback tank.

[0010] Various refinements of the features noted above may exist in relation to various aspects of the present embodiments. Further features may also be incorporated in these various aspects as well. These refinements and additional features may exist individually or in any combination. For instance, various features discussed below in relation to the illustrated embodiments may be incorporated into any of the above-described aspects of the present disclosure alone or in any combination. Again, the brief summary presented above is intended just to familiarize the reader with certain aspects and contexts of some embodiments without limitation to the claimed subject matter.

BRIEF DESCRIPTION OF THE DRAWINGS

[0011] Certain embodiments of the disclosure will hereafter be described with reference to the drawings, wherein like reference numerals denote like elements. It should be understood, however, that the accompanying drawings illustrate just the various implementations described herein and are not meant to limit the scope of various technologies described herein. The drawings show and describe various embodiments of the current disclosure. More specifically:

[0012] FIG. 1 generally depicts an apparatus for monitoring parameters of fluid flowing from a well during flowback operations at a wellsite in accordance with one embodiment;

[0013] FIG. 2 is a schematic of a flowback apparatus having a flowback tank equipped with a load cell in accordance with one embodiment;

[0014] FIG. 3 is a schematic of a flowback apparatus having a flowback tank and load cells positioned on a trailer in accordance with one embodiment;

[0015] FIGS. 4 and 5 generally depict fluid level sensors having floats for measuring fluid levels in a flowback tank in accordance with certain embodiments;

[0016] FIG. 6 is a schematic of a flowback apparatus with an open-top flowback tank equipped with load cells and fluid level sensors in accordance with one embodiment;

[0017] FIG. 7 is a schematic of a flowback apparatus with an enclosed flowback tank equipped with load cells and fluid level sensors in accordance with one embodiment;

[0018] FIG. 8 is a flowchart for monitoring parameters of a multiphase fluid received in a tank in accordance with one embodiment; and

[0019] FIG. 9 is a block diagram of components of a computer for monitoring parameters of a multiphase fluid received in a tank in accordance with one embodiment.

DETAILED DESCRIPTION

[0020] In the following description, numerous details are set forth to provide an understanding of the present disclosure. It will be understood by those skilled in the art, however, that the embodiments of the present disclosure may be practiced without these details and that numerous variations or modifications from the described embodiments may be possible.

[0021] In the specification and appended claims: the terms “connect,” “connection,” “connected,” “in connection with,” and “connecting” are used to mean “in direct connection with” or “in connection with via one or more elements,” and the term “set” is used to mean “one element” or “more than one element.” Further, the terms “couple,” “coupling,” “coupled,” “coupled together,” and “coupled with” are used to mean “directly coupled together” or “coupled together via one or more elements.” As used herein, the terms “up” and “down”; “upper” and “lower”; “upwardly” and “downwardly”; “upstream” and “downstream”; “above” and “below”; and other like terms indicating relative positions above or below a given point or element are used in this description to more clearly describe some embodiments of the disclosure. When introducing elements of various

embodiments, 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.

[0022] Certain embodiments of the present disclosure generally relate to a flowback apparatus for measuring components of a multiphase fluid during well flowback operations. The flowback apparatus can include a container, such as a vertical or horizontal flowback tank, equipped with at least one load cell. In some embodiments, the flowback apparatus includes an open-top or enclosed container equipped with at least one fluid level sensor and at least one load cell positioned below the container. The flowback apparatus may also include one or more of a gas buster, a gas flowmeter, or a pressure relief valve. Volumes (or masses) of each produced phase and of solids (e.g., sand), as well as their production rates, can be computed from data acquired from level sensors, load cells, and gas flowmeters using densities that can be obtained from evaluation of samples from the multiphase fluid. The level sensors, load cells, and flowmeters can be connected to an acquisition system enabling continuous monitoring of flowback parameters (e.g., volumes, rates, and pressure).

[0023] Turning now to the present figures, an example of an apparatus 10 for monitoring parameters of fluid flowing from a well 12 during flowback operations at a wellsite is provided in FIG. 1 in accordance with one embodiment. While certain elements of the apparatus 10 are depicted in this figure and generally discussed below, it will be appreciated that the apparatus 10 may include other components in addition to, or in place of, those presently illustrated and discussed.

[0024] As shown in FIG. 1, the apparatus 10 includes a wellhead assembly 14 mounted over the well 12. Flowback fluid may be produced from the well 12 through the wellhead assembly 14 and routed to a flowback assembly 16. The flowback assembly 16 can include a tank (e.g., a sand separator, a well test separator, or some other container) and one or more load cells 18 for weighing the tank. As described in more detail below, the flowback assembly 16 may also include one or more other measurement devices, such as fluid level sensors, gas flowmeters, temperature sensors, or pressure sensors,

for acquiring additional information about flowback operation parameters. The apparatus 10 can also include a sampling system 20 for collecting samples from the flowback fluid, such as samples of solid particulates and one or more fluid phases (e.g., gas, oil, or water) received at the flowback assembly 16 from the well 12. In some embodiments, such samples may be used to measure densities of solids, water, or oil in the flowback fluid.

[0025] A data analyzer 22 (e.g., a processor-based computer) can monitor rates and produced volumes of components of the multiphase fluid and solids. As discussed further below, such monitoring by the data analyzer 22 can be based on various acquired measurements, such as a weight of the tank measured with the load cell 18, a fluid level in the tank, densities of solids or fluid phases of the flowback fluid, pressure, or temperature. In some embodiments, measurements acquired by the data analyzer 22 are processed to determine volumes and rates of at least two produced phases of the multiphase fluid routed to the tank. Further, in some embodiments the data analyzer 22 determines in real-time a volume or mass of one or more of the solids or individual fluid phases received in the tank while the multiphase fluid is flowing into the tank (e.g., during a flowback operation), which may facilitate real-time operational decision-making at a wellsite.

[0026] The flowback assembly 16 can be an integrated system in which the tank, load cell 18, and any other sensors of the assembly 16 are mounted and transported in the same apparatus, which may reduce rig up time at a wellsite. The flowback assembly 16 may also be equipped with several drain ports or hatches that can be used for draining multiphase fluid from the apparatus (e.g., from the tank) and cleaning out solids (e.g., by flushing or using vacuum-trucks or similar units).

[0027] The flowback assembly 16 may take various forms. In one embodiment, the flowback assembly 16 is provided as a flowback apparatus 30 as illustrated in FIG. 2. The depicted flowback apparatus 30 includes a flowback tank 32 with an inlet 34 for receiving a multiphase fluid, such as flowback fluid from the well 12. The multiphase fluid may be routed into the inlet 34 (as generally indicated by arrow 36) and received in a chamber 38 of the tank 32. Tank 32 is generally shown as a vertical sand separator in

FIG. 2, but other vertical or horizontal tanks 32 could be used. The depicted tank 32 is an enclosed tank with a fixed volume for separating and collecting solids 40 (e.g., entrained sand) from the fluid entering the tank 32. Within the chamber 38, solids 40 may settle to the bottom of the tank 32 from the multiphase fluid (as generally indicated by arrow 46), while remaining portions of the multiphase fluid may exit through an outlet 42 (as generally indicated by arrow 44).

[0028] The depicted flowback apparatus 30 is equipped with a load cell 18 that can be used for measuring mass of the accumulated sand. More specifically, the mass of the accumulated sand (i.e., produced sand) may be computed by the data analyzer 22 for a time t based on the total mass measured by the load cell 18 at time t , the mass of the tank 32 when empty, the volume of the tank 32, and densities of the liquid and sand within the tank 32, such as follows:

$$M(t)_{producedsand} = \frac{M(t)_{total} - M_{emptyapparatus} - V_{apparatus}\rho_{liquid}}{1 - \frac{\rho_{liquid}}{\rho_{sand}}} \quad (\text{Eq. 1})$$

The mass of the tank 32 at time t and the mass of the tank 32 when empty can be measured with the load cell 18. Although the measurements can be provided from the load cell 18 to the data analyzer 22 via a communication line 48, it will be appreciated that the measurements could be provided wirelessly in some instances. The densities of the liquid and sand entering the tank 32 may be measured (e.g., via sampling of the multiphase fluid) or estimated in any suitable manner. Further, the rate of sand production can be calculated as a time derivative of accumulated mass:

$$U(t)_{producedsand} = \frac{dM(t)_{producedsand}}{dt} \quad (\text{Eq. 2})$$

[0029] In the case of multiphase fluid that includes water, oil, and gas, most of the volume of the tank 32 can be filled with water (oil and gas have specific gravity lower than specific gravity of water and will predominately flow to the top of the apparatus and then will be flushed away). In this case, mass of accumulated sand may approximately be computed as:

$$M(t)_{producedsand} = \frac{M(t)_{total} - M_{emptyapparatus} - V_{apparatus}\rho_{water}}{1 - \frac{\rho_{water}}{\rho_{sand}}} \quad (\text{Eq. 3})$$

and the rate of sand production can be calculated as a time derivative of accumulated mass, as described above.

[0030] In another embodiment depicted in FIG. 3, the flowback assembly 16 includes a flowback apparatus 56 having a flowback tank 58. As presently depicted, the flowback tank 58 is a container on a trailer 60. Load cells 62 are positioned below the tank 58 for weight measurement. The tank 58 could be a horizontal tank, as shown, or a vertical tank. Moreover, the tank 58 could be an enclosed or open-top container; when enclosed, the interior of the container could be at ambient pressure or could be pressurized. In at least some embodiments, the container includes an overflow port that controls the fluid level in the tank 58.

[0031] Handrails 64 may be provided to facilitate operator movement on the trailer 60 along the tank 58. The trailer 60 can include wheels to facilitate movement of the flowback apparatus 56 and one or more legs 66 for supporting the trailer 60 when positioned at a wellsite or fixed location. The tank 58 can be leveled at a site before receiving the multiphase fluid (e.g., flowback fluid from the well 12). One or more legs 66 can include a jack for raising or lowering a portion of the trailer 60 to facilitate leveling of the tank 58. Other jacks may also or instead be provided elsewhere in the apparatus 56.

[0032] The flowback tank 58 can be used in some embodiments for measuring an amount (mass or volume) of sand in the case of producing sand and a single-phase liquid fluid with potential content of gaseous phase practically insoluble in the liquid phase (e.g., water, or water with nitrogen or natural gas). A gaseous phase of the received fluid may be released to atmosphere and does not impact measurements. In this, case mass of produced sand at each time moment can be computed as:

$$M(t)_{producedsand} = \frac{M(t)_{total} - M_{emptycontainer} - V_{container}\rho_{fluid}}{1 - \frac{\rho_{fluid}}{\rho_{sand}}} \quad (\text{Eq. 4})$$

Sand production rate at each time moment can be computed as a time derivative of the produced sand mass.

$$U(t)_{producedsand} = \frac{dM(t)_{producedsand}}{dt} \quad (\text{Eq. 5})$$

[0033] Flowback tanks 58 of some embodiments can be equipped with fluid level sensors that can be used to measure level and volume of components (e.g., individual fluid phases) of multiphase fluid within the tanks 58. Such fluid level sensors may take any suitable form, but in certain embodiments include floats for detecting fluid levels within a tank. Two examples of such fluid level sensors having floats are depicted in FIGS. 4 and 5.

[0034] As shown in FIG. 4, a multiphase fluid received in the flowback tank 58 may separate into a first phase 70 and a second phase 72. The first phase 70 may be water and the second phase 72 may be oil (or, more generally, a liquid hydrocarbon). The second phase 72 has a lower boundary 74 (along the first phase 70) and an upper boundary 76 (along a gaseous phase, or air, above the second phase 72). A fluid level sensor 82 can include floats 84 and 86 for detecting the location of the lower boundary 74 (i.e., the level of the first phase 70 within the tank 58) and the upper boundary 76 (i.e., the level of the second phase 72 within the tank 58). The density of the float 84 is less than the density of the first phase 70 and greater than the density of the second phase 72. This causes the float 84 to remain with the lower boundary 74. The density of the float 86 is less than the density of each of the first and second phases 70 and 72 and is greater than the density of a gas layer (e.g., a gas phase of the multiphase fluid or ambient air) overlying the second phase 72, which causes the float 86 to remain with the upper boundary 76. By way of example, in one embodiment the multiphase fluid may include water, oil, and gas phases with respective densities of 1g/cm³; 0.7–0.9g/cm³ and <0.01g/cm³ (at operating conditions), a first float 84 having a density of 0.9–1g/cm³ (between the water and oil phase densities), and a second float 86 having a density of 0.01–0.7g/cm³ (between the oil and gas phase densities).

[0035] The fluid level sensor 82 measures the position of the floats 84 and 86 and can communicate these measurements (e.g., to the data analyzer 22) via a communication line 88 or in some other suitable manner (e.g., wirelessly). The geometry of the tank 58 is known, and the volume of individual fluid components within the tank 58 can be computed from the geometry and the positions of corresponding floats in the tank 58. Although one fluid level sensor 82 may have floats 84 and 86, in other embodiments the floats 84 and 86 are with separate fluid level sensors 82, such as generally depicted in FIG. 5. One or more fluid level sensors 82 can be connected to an acquisition system (e.g., data analyzer 22) that enables real-time measurements and computations of fluid component parameters (e.g., volumes, masses, or rates).

[0036] By way of further example, an open-top flowback tank 58 with fluid level sensors 82 is illustrated in FIG. 6. In this depicted embodiment, the tank 58 and load cells 62 are supported by a platform 92, such as a trailer bed or a skid. A multiphase fluid may be routed (arrow 96) into the tank 58 through a gas buster 98, which may help separate gas from liquid of the incoming multiphase fluid. Solid particulates 104 (e.g., sand) settle in the tank 58 and floats 84 and 86 are used to measure the levels of the separated first phase 70 and second phase 72 within the tank. A gas layer 102 (e.g., air in the open-top tank 58 of FIG. 6) overlies the second phase 72. The tank 58 can be used to measure flow rate and volumes of solid and liquid components of multiphase fluid. Gaseous components can be released to atmosphere (e.g., through the open top of the tank 58) and do not impact measurements. For example, for a water/oil/gas/sand mixture, masses and volumes at each time moment may be given as:

$$M(t)_{producedsand} = \frac{M(t)_{total} - M_{emptycontainer} - V_{volumeto\ 1st\ float}\rho_{water} - V_{volumeto\ 2nd\ float}\rho_{oil} + V_{volumeto\ 1st\ float}\rho_{oil}}{1 - \frac{\rho_{water}}{\rho_{sand}}} \quad (\text{Eq. 6})$$

$$V(t)_{producedwater} = V_{volumeto\ 1st\ float} - \frac{M(t)_{producedsand}}{\rho_{sand}} \quad (\text{Eq. 7})$$

$$V(t)_{producedoil} = V_{volumeto\ 2nd\ float} - V_{volumeto\ 1st\ float} \quad (\text{Eq. 8})$$

[0037] Further, the masses of the produced water and oil can be computed from their densities and volumes ($\rho V = M$), the volume of the produced sand can be computed from its density and mass, and production rates may be computed as:

$$U(t)_{producedsand} = \frac{dM(t)_{producedsand}}{dt} \quad (\text{Eq. 9})$$

$$Q(t)_{producedwater} = \frac{dM(t)_{producedwater}}{dt} \quad (\text{Eq. 10})$$

$$Q(t)_{producedoil} = \frac{dM(t)_{producedoil}}{dt} \quad (\text{Eq. 11})$$

[0038] In a still further embodiment, an enclosed flowback tank 58 with fluid level sensors 82 is illustrated in FIG. 7. The flowback tank 58 of FIG. 7 is similar to that of FIG. 6 but may instead be hermetical and rated to a pressure level. In some instances, the rated pressure level may be a low-pressure level (e.g., 5–10 psi), though the tank 58 may be rated to a higher pressure in full accordance with the present technique. The flowback tank 58 of FIG. 7 can be used for measuring volumes and rates of each component of multiphase fluid, such as water, oil, gas, and sand.

[0039] The flowback tank 58 of FIG. 7 is equipped with a gas flowmeter 112, a pressure relief valve 114, and one or more additional sensors 116 (e.g., pressure sensor or temperature sensor). Gas rate of the multiphase fluid can be measured by the gas flowmeter 112 (which receives separated gas 102 from the multiphase fluid) and the total produced gas volume can be computed by integrating measured gas rate over a period of time.

[0040] Produced sand volume can be computed as:

$$M(t)_{producedsand} = \frac{M(t)_{total} - M_{emptycontainer} - V_{total}\rho_{gas}(P,T) - V_{volumeto\ 1st\ float}\rho_{water} - V_{volumeto\ 2nd\ float}\rho_{oil} + V_{volumeto\ 1st\ float}\rho_{oil}}{1 - \frac{\rho_{water}}{\rho_{sand}}} \quad (\text{Eq. 12})$$

wherein $\rho_{gas}(P, T)$ can be computed from the Mendeleev-Clapeyron gas state equation as:

$$\rho_{gas}(P, T) = \frac{PM_r}{RT} \quad (\text{Eq. 13})$$

and wherein M_r is the molecular mass of the produced gas, P is pressure, T is temperature and R is the universal gas constant. The other volumes and rates may be computed as discussed above with respect to the embodiment of FIG. 6.

[0041] Turning now to FIG. 8, an example of a process for measuring components of multiphase fluid during a flowback operation is generally represented by flowchart 130. In this embodiment, a multiphase fluid is received in a flowback tank (block 132). In at least some instances, the multiphase fluid includes a water phase, a liquid hydrocarbon (e.g., oil) phase, and entrained sand (which may include small amounts of other particulates). The multiphase fluid could also include a gas phase in some cases. The multiphase fluid may be received in any suitable flowback tank, such as the various tanks described above. The process also includes measuring densities of fluid phases and of sand from the multiphase fluid (block 134). For example, a density of a water phase, a density of a liquid hydrocarbon phase, and a density of sand from the multiphase fluid can be measured via sampling. A weight of the flowback tank can also be measured (block 136), such as with one or more load cells 62. This can include measuring the weight of the flowback tank during a flowback operation (e.g., while multiphase fluid components are flowing into the tank). In some instances, the weight of the flowback tank can also be measured via load cells 62 while empty (e.g., before the flowback operation).

[0042] The process also includes determining phase boundaries in the flowback tank (block 138). In at least some instances, this includes determining the lower and upper boundaries (e.g., boundaries 74 and 76) of a liquid hydrocarbon phase (e.g., second phase 72) in the flowback tank during a flowback operation. Volumes of the flowback tank below these determined boundaries may then be determined (block 140) based on the detected boundaries and the known geometry of the flowback tank. In one embodiment, for instance, this includes determining a volume of the flowback tank below a determined

lower phase boundary (e.g., boundary 74) and determining a volume of the flowback tank below a determined upper phase boundary (e.g., boundary 76).

[0043] Further, the process includes calculating an amount (i.e., mass or volume) of sand in the flowback tank (block 142), such as described above. In some embodiments, the mass of the sand in the flowback tank is calculated based on the measured densities of a water phase, a liquid hydrocarbon phase, and the sand; the measured weight of the flowback tank during flowback; and the determined phase boundaries within the flowback tank. The determined volumes of the flowback tank below the phase boundaries may also be used. The mass or volume of produced fluid phases of the multiphase fluid (block 144) and production rates for sand and fluid phases (block 146) entering the flowback tank may also be calculated, such as described above. In at least some embodiments, the weight measurement (block 136), the determinations of phase boundaries and tank volumes below the boundaries (blocks 138 and 140), and the calculations of mass, volume, and production rates (blocks 142, 144, and 146) are performed in real-time during a flowback operation. Moreover, some embodiments include continually (e.g., intermittently or continuously) calculating production rates of sand, a water phase, and a liquid hydrocarbon phase in the multiphase fluid during the flowback operation.

[0044] The above techniques can be implemented with the data analyzer 22, which may be provided as a processor-based system. More specifically, and with reference to FIG. 9, in one embodiment the data analyzer 22 is provided in the form of a computer 150 including at least one processor 152 connected by a bus 154 to volatile memory 156 (e.g., random-access memory) and non-volatile memory 158 (e.g., flash memory and a read-only memory (ROM)). Coded application instructions 160 and data 162 are stored in the non-volatile memory 158. For example, the application instructions 160 can be stored in a ROM and the data 162 can be stored in a flash memory. The instructions 160 and the data 162 may be also be loaded into the volatile memory 156 (or in a local memory 164 of the processor) as desired, such as to reduce latency and increase operating efficiency of the computer 150. The coded application instructions 160 can be provided as software that may be executed by the processor 152 to enable various functionalities described herein. Non-limiting examples of these functionalities include

receiving data (e.g., phase and sand densities, and measurements from load cells, fluid level sensors, and other sensors); determining phase boundaries in a flowback tank; determining volumes of the flowback tank below the phase boundaries; and calculating masses, volumes, and production rates of components (e.g., solids and individual fluid phases) of a multiphase fluid flowing into the tank, such as described above. In at least some embodiments, the application instructions 160 are encoded in a non-transitory computer readable storage medium, such as the volatile memory 156, the non-volatile memory 158, the local memory 164, or a portable storage device (e.g., a flash drive or a compact disc).

[0045] An interface 166 of the computer 150 enables communication between the processor 152 and various input devices 168 and output devices 170. The interface 166 can include any suitable device that enables such communication, such as a modem (wired or wireless) or a serial port. In some embodiments, the input devices 168 include one or more sensing components (e.g., load cells 62, fluid level sensors 82, gas flowmeter 112, or other sensors 116) and the output devices 170 include displays, printers, and storage devices that allow output of data received or generated by the computer 150. In some instances, for example, one or more of the calculated masses, volumes, or rates can be provided to an operator for consideration or to another computer routine or system for further processing or storage. Input devices 168 and output devices 170 may be provided as part of the computer 150 or may be separately provided.

[0046] Further, while the computer 150 could be located with the flowback tank and sensing components as an integrated system, the computer 150 could also be located remote from the other components. Additionally, the computer 150 could be provided as a distributed system with a portion of the computer 150 located with the flowback tank and the remaining portion of the computer 150 at a remote location. One or more communication devices (e.g., of the interface 166) may facilitate wired or wireless communications of the generated data (e.g., masses, volumes, or production rates of one or more components of the multiphase fluid) to users' process-management systems, such as to a supervisory control and data acquisition (SCADA) system.

[0047] The foregoing outlines features of several embodiments so that those skilled in the art may better understand aspects of the present disclosure. Those skilled 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 or achieving the same advantages of the embodiments introduced herein. Those skilled in the art should also realize that such equivalent constructions do not depart from the spirit and 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.

Claims:

1. An apparatus comprising:
 - a tank configured to receive a multiphase fluid including solids and multiple fluid phases from a well;
 - at least one load cell positioned below the tank;
 - at least one fluid level sensor positioned to measure at least one fluid level in the tank; and
 - a processor-based data analyzer configured to determine a volume or mass of the solids of the multiphase fluid received in the tank and individual phase volumes or masses of two or more of the multiple fluid phases of the multiphase fluid received in the tank based on data acquired via the at least one load cell and the at least one fluid level sensor.
2. The apparatus of claim 1, wherein the processor-based data analyzer is configured to determine rates at which the solids and the two or more of the multiple fluid phases are received in the tank.
3. The apparatus of claim 2, wherein the processor-based data analyzer is configured to determine the rates, as well as the volumes or masses, of the solids and the two or more of the multiple fluid phases in real-time during a flowback operation in which the multiphase fluid is directed from the well into the tank.
4. The apparatus of claim 1, wherein the two or more of the multiple fluid phases include a first liquid phase and a second liquid phase, and the processor-based data analyzer is configured to determine the volume or mass of the solids and the individual phase volumes or masses of the first liquid phase and the second liquid phase based on the data acquired via the at least one load cell and the at least one fluid level sensor.

5. The apparatus of claim 4, wherein the at least one fluid level sensor includes a first float having a density less than a density of the first liquid phase and greater than a density of the second liquid phase.
6. The apparatus of claim 5, wherein the at least one fluid level sensor includes a second float having a density less than the density of the first liquid phase, less than the density of the second liquid phase, and greater than a density of a gas layer above the second liquid phase.
7. The apparatus of claim 5, wherein the first liquid phase is a water phase and the second liquid phase is an oil phase.
8. The apparatus of claim 5, wherein the multiphase fluid includes a gas phase.
9. The apparatus of claim 8, comprising a gas flowmeter positioned to receive gas from the multiphase fluid.
10. The apparatus of claim 8, comprising a gas buster in the tank to facilitate separation of the gas phase from the multiphase fluid.
11. The apparatus of claim 1, comprising a trailer having the tank, the at least one load cell, and the at least one fluid level sensor.
12. An apparatus comprising:
 - a tank configured to receive a fluid including solid particulates from a well;
 - at least one load cell positioned below the tank; and
 - a processor-based data analyzer configured to determine a volume or mass of the solid particulates received in the tank in real-time as the fluid flows into the tank based on a weight of the tank measured via the at least one load cell.
13. The apparatus of claim 12, wherein the tank includes a fluid level sensor.

14. The apparatus of claim 12, wherein the processor-based data analyzer includes a computer encoded with instructions to calculate the volume or mass of the solid particulates based on the weight of the tank measured via the at least one load cell, a volume of the tank, and densities of solid and liquid components of the fluid.
15. The apparatus of claim 14, wherein the computer is encoded with instructions to calculate the rate at which the solid particulates are entering the tank.
16. A method comprising:
- receiving a multiphase fluid from a well into a flowback tank during a flowback operation, the multiphase fluid including a water phase, a liquid hydrocarbon phase, and entrained sand;
 - measuring densities of the water phase, the liquid hydrocarbon phase, and the sand;
 - measuring a weight of the flowback tank during the flowback operation;
 - determining lower and upper boundaries of the liquid hydrocarbon phase within the flowback tank; and
 - calculating at least one of a mass or volume of the sand received in the flowback tank with the multiphase fluid based on the measured densities of the water phase, the liquid hydrocarbon phase, and the sand, on the weight of the flowback tank measured during the flowback operation, and on the determined lower and upper boundaries of the liquid hydrocarbon phase within the flowback tank.
17. The method of claim 16, comprising:
- determining a volume of the flowback tank below the determined lower boundary of the liquid hydrocarbon phase;
 - determining a volume of the flowback tank below the determined upper boundary of the liquid hydrocarbon phase; and
 - using the determined volumes of the flowback tank in calculating the at least one of the mass or volume.

18. The method of claim 16, comprising raising or lowering at least one portion of a trailer carrying the flowback tank to level the flowback tank before receiving the multiphase fluid from the well into the flowback tank.
19. The method of claim 16, wherein calculating at least one of the mass or volume of the sand received in the flowback tank with the multiphase fluid is performed in real-time during the flowback operation.
20. The method of claim 16, comprising continually calculating production rates of the sand, the water phase, and the liquid hydrocarbon phase during the flowback operation.

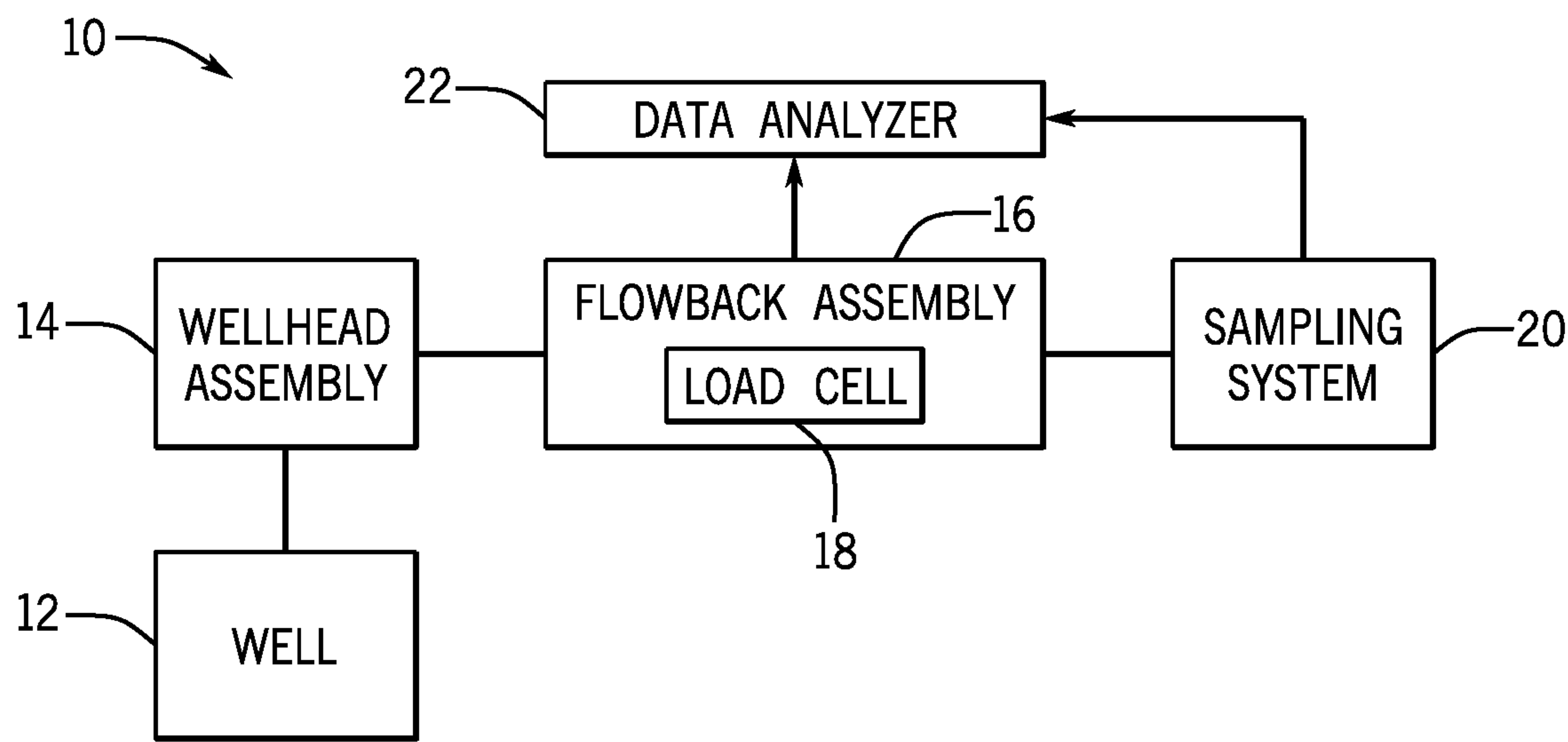


FIG. 1

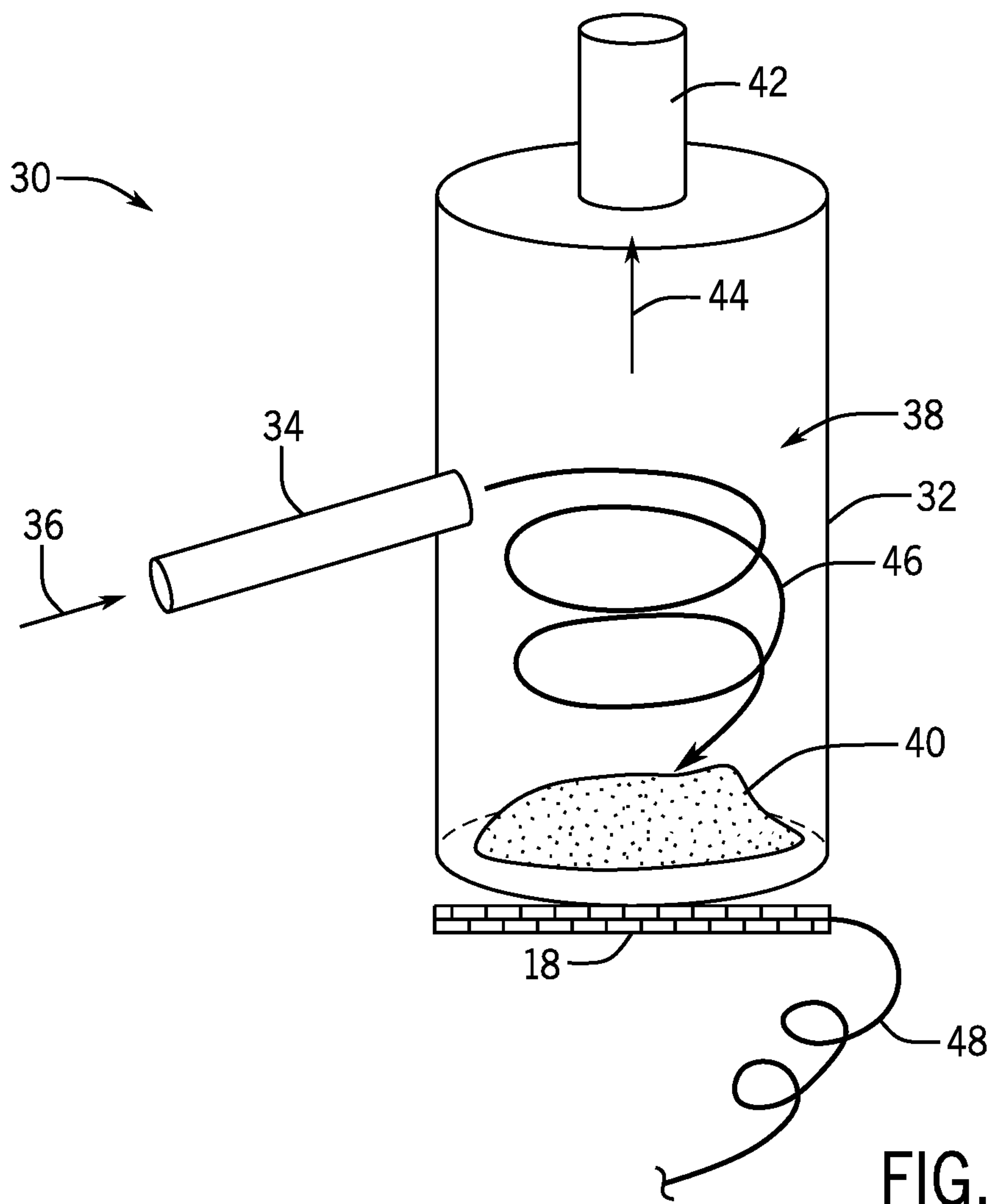


FIG. 2

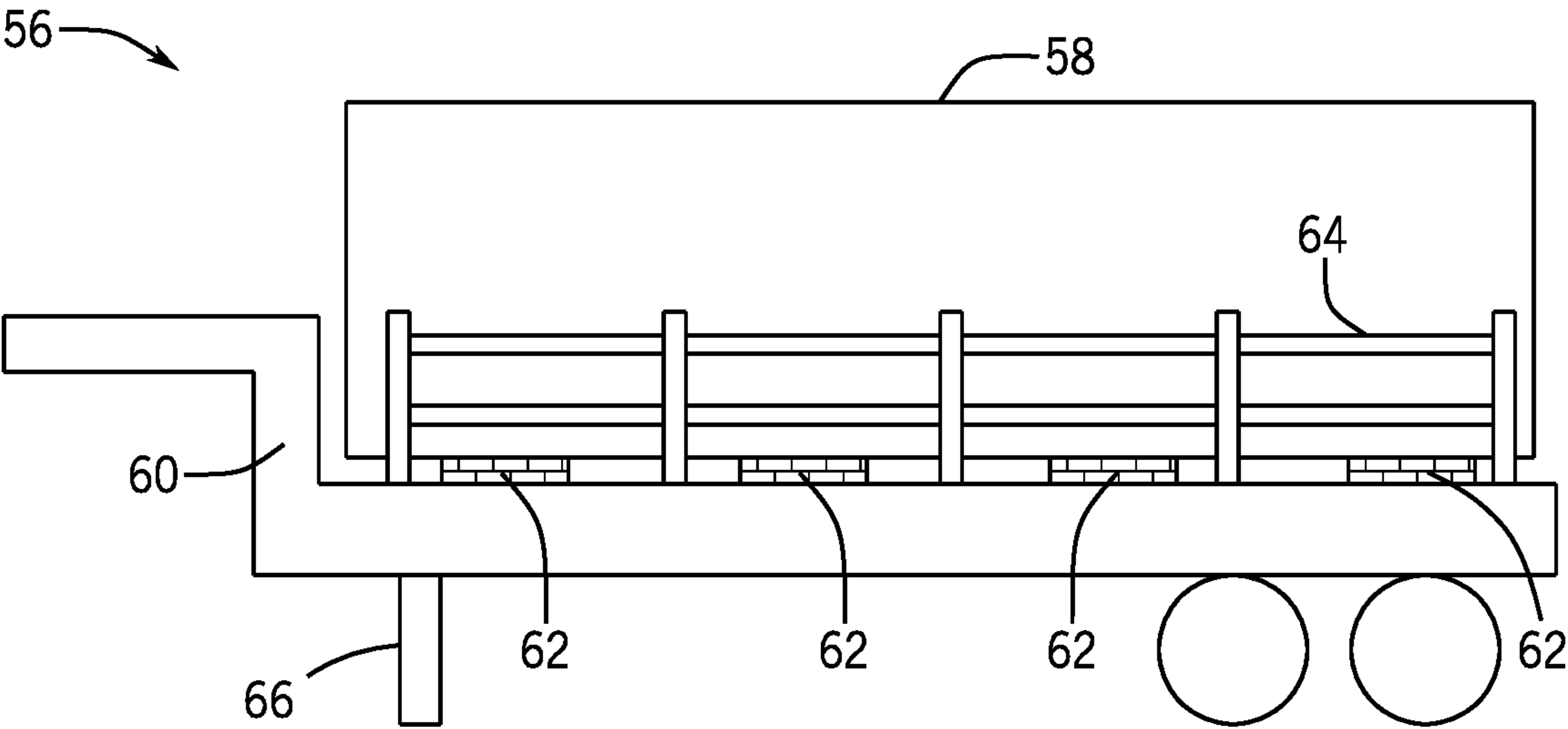


FIG. 3

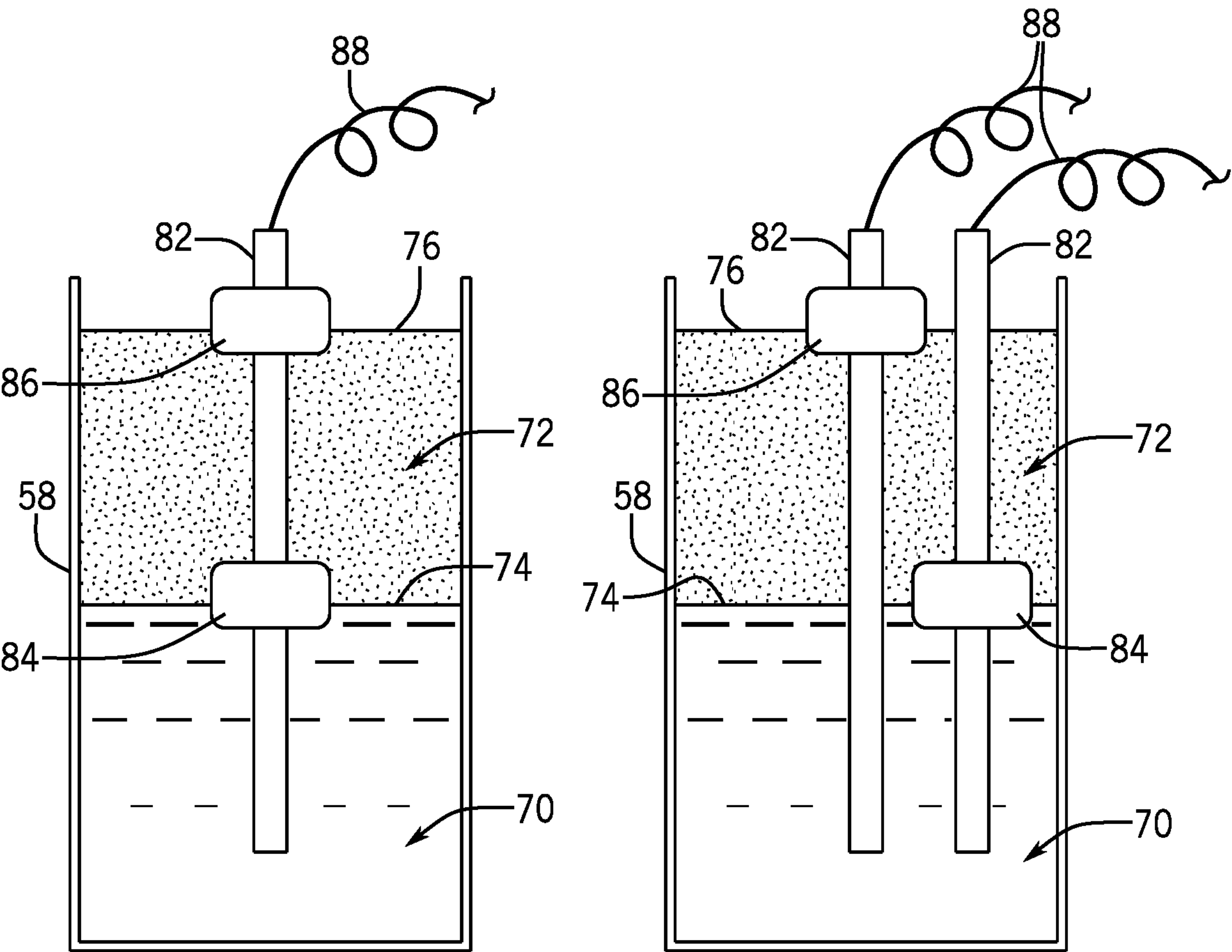


FIG. 4

FIG. 5

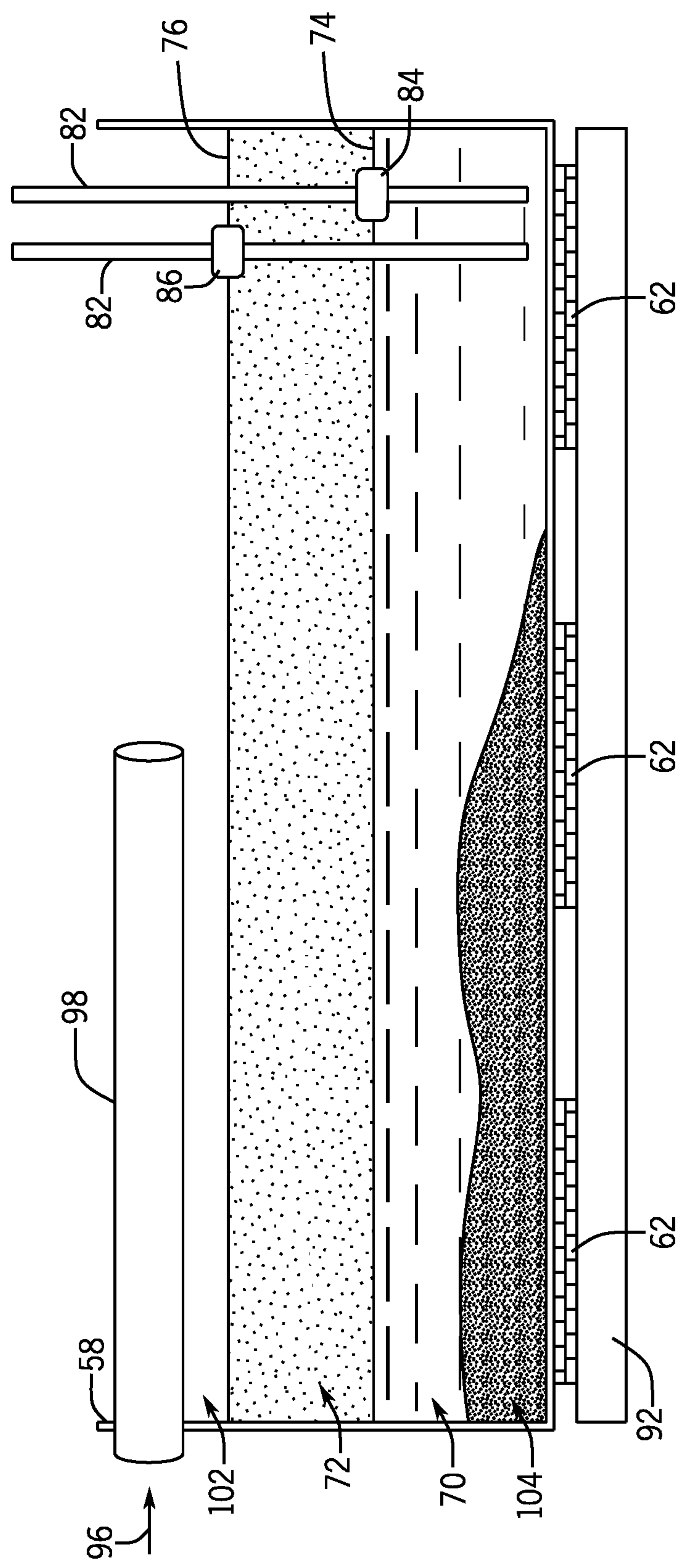


FIG. 6

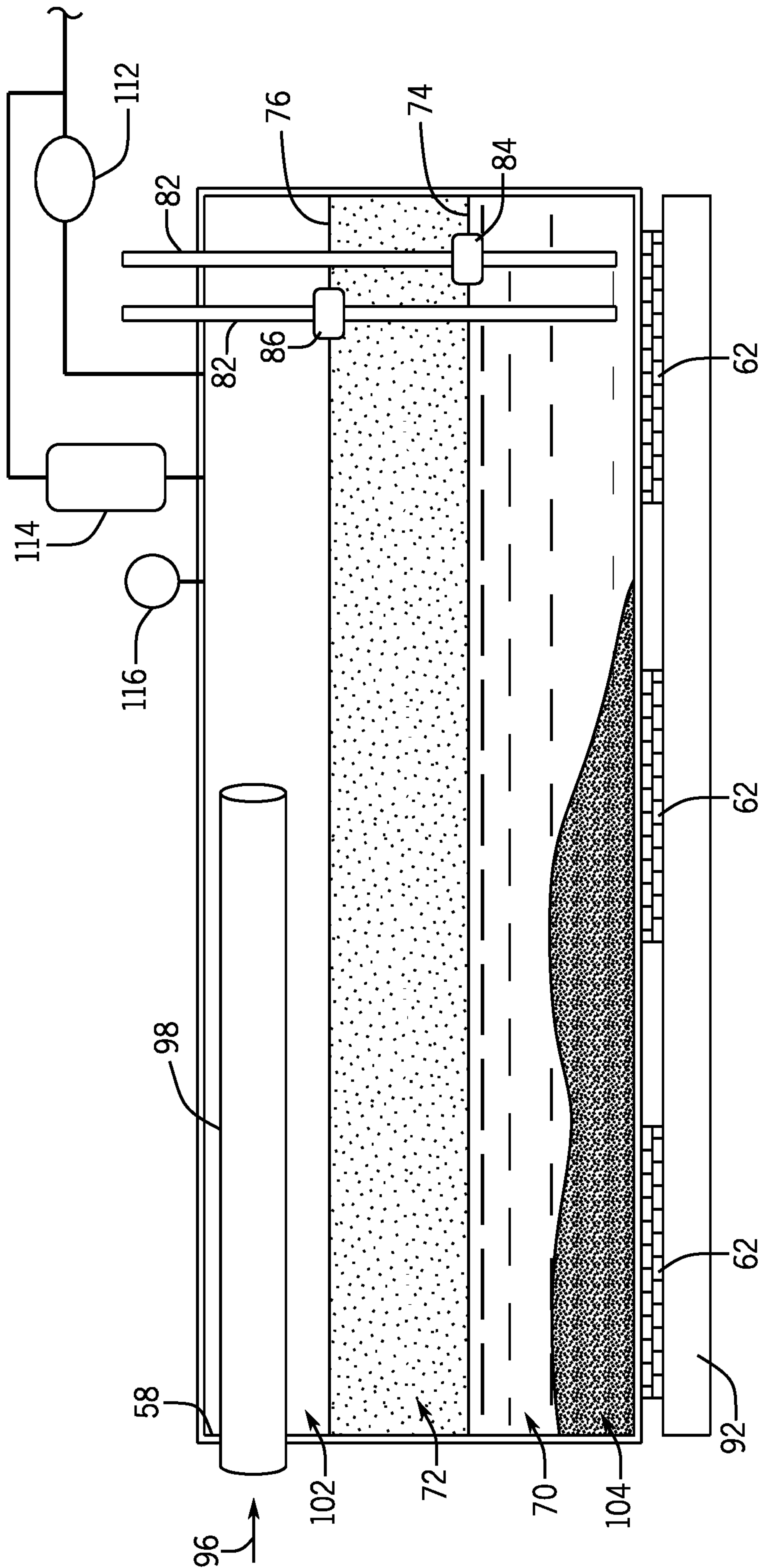


FIG. 7

5 / 6

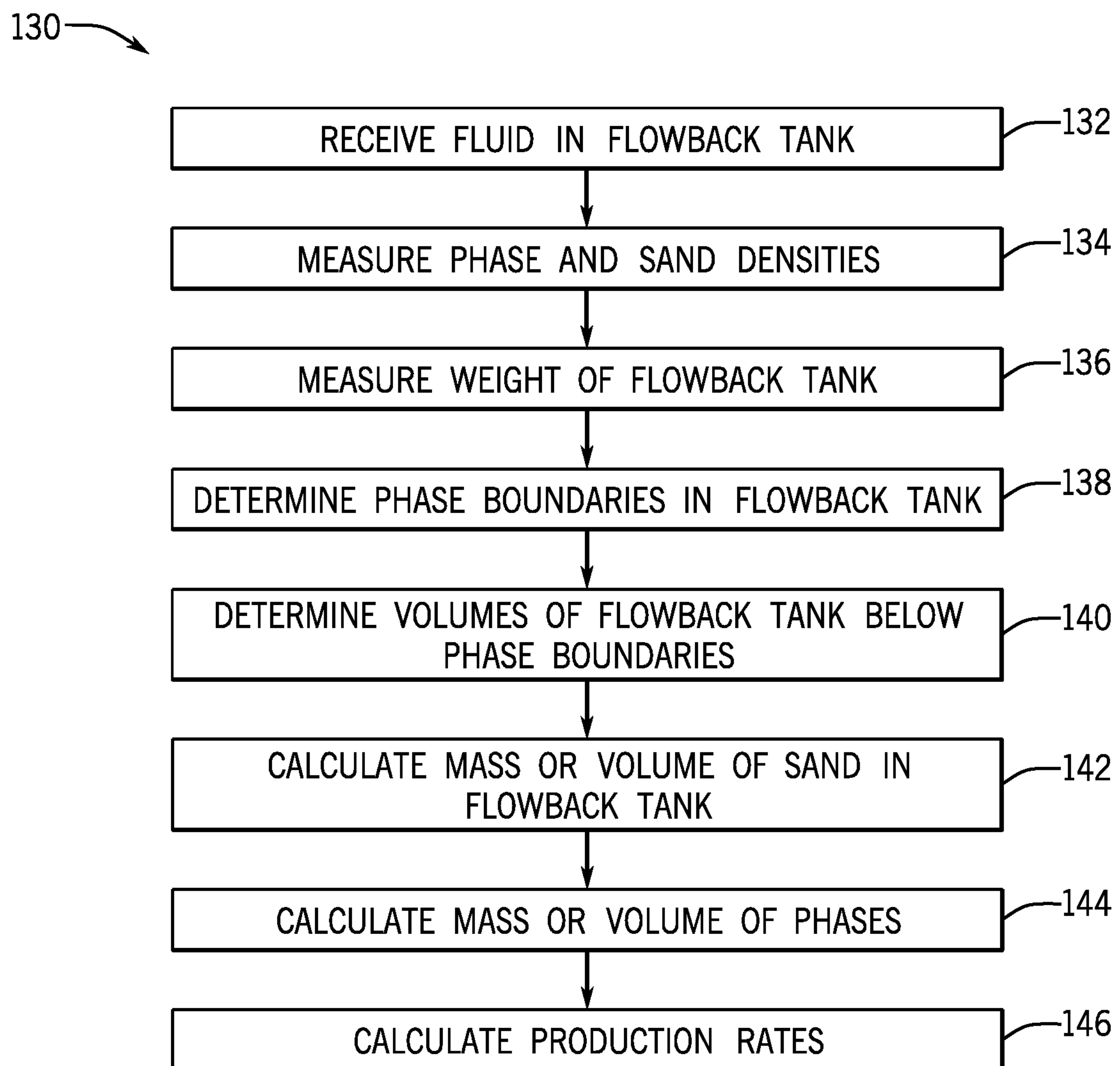


FIG. 8

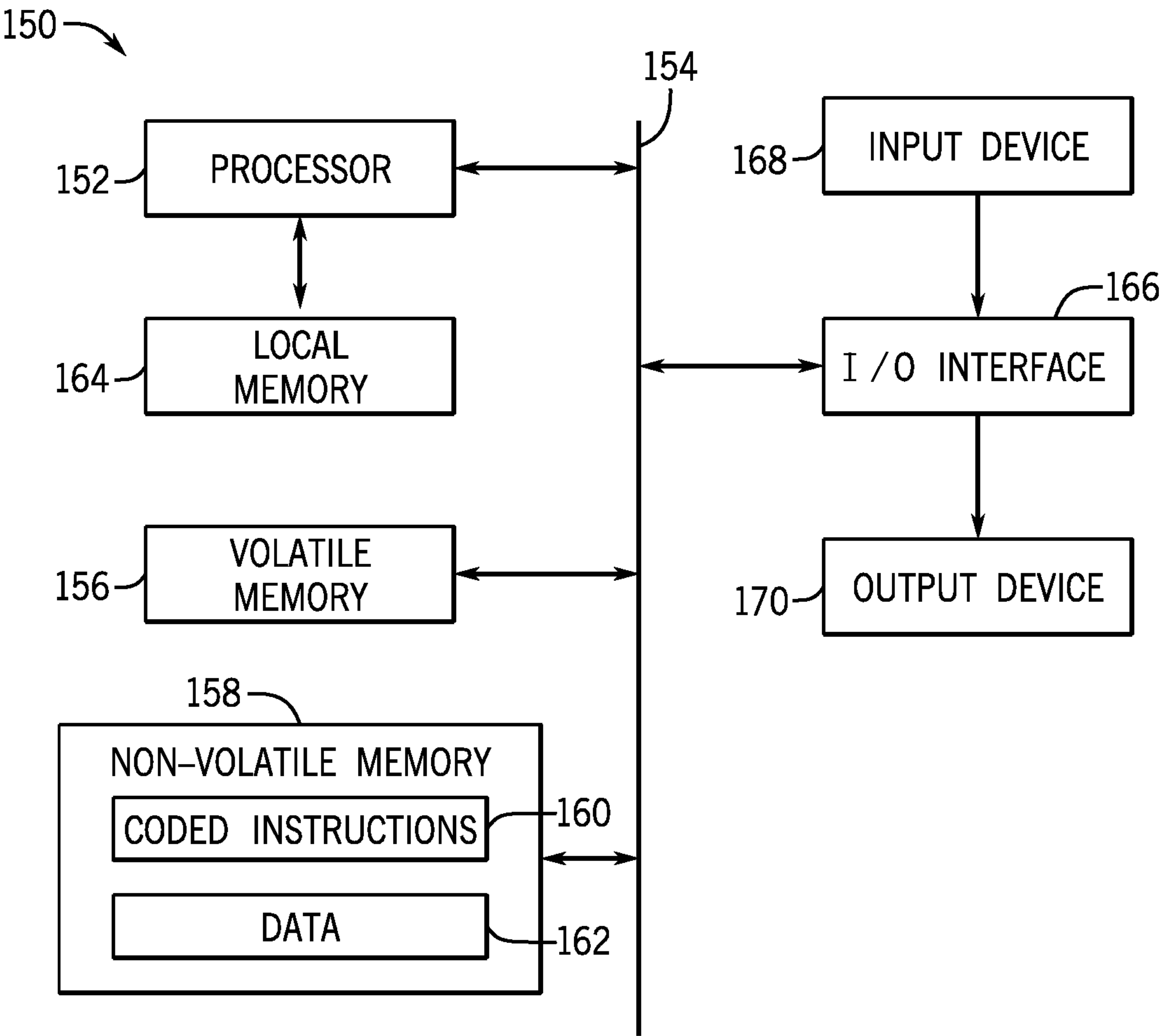


FIG. 9