



- (51) International Patent Classification:
E21B 47/10 (2012.01) *E21B 49/08* (2006.01)
E21B 47/06 (2012.01)
- (21) International Application Number:
PCT/US20 12/070852
- (22) International Filing Date:
20 December 2012 (20.12.2012)
- (25) Filing Language: English
- (26) Publication Language: English
- (30) Priority Data:
11290612.8 23 December 2011 (23.12.2011) EP
- (71) Applicant (for FR only): **SERVICES PETROLIERS SCHLUMBERGER** [FR/FR]; 42 rue Saint Dominique, F-75007 Paris (FR).
- (71) Applicant (for AL, AM, AT, AU, AZ, BF, BG, BJ, BN, BY, CF, CG, CH, CI, CL, CM, CO, CY, CZ, DE, DK, EG, GA, GE, GN, GQ, GR, GW, HR, HU, ID, IE, IL, IT, KE, KG, KP, KR, KZ, LT MD, MG, ML, MR, MX, MY, NE, NO, NZ, OM, PL, QA, RO, RU, SI, SK, SN, TD, TG, TH, TJ, TM, TN, TR, TT TZ, UA, UG, UZ, ZA only): **SCHLUMBERGER TECHNOLOGY B.V.** [NL/NL]; Parkstraat 83-89m, NL-25 14 JG The Hague (NL).
- (71) Applicant (for GB, JP, NL only): **SCHLUMBERGER HOLDINGS LIMITED**; P.O. Box 71, Craigmuir Chambers, Tortola, Road Town, 1110 (VG).

[Continued on nextpage]

(54) Title: SYSTEM AND METHOD FOR MEASURING FORMATION PROPERTIES

(57) Abstract: Pressure of a fluid in a geological formation is predicted using measured temperature and pressure changes following the creation of a pressure reduction in a flowline in fluid communication with the fluid in the geological formation.

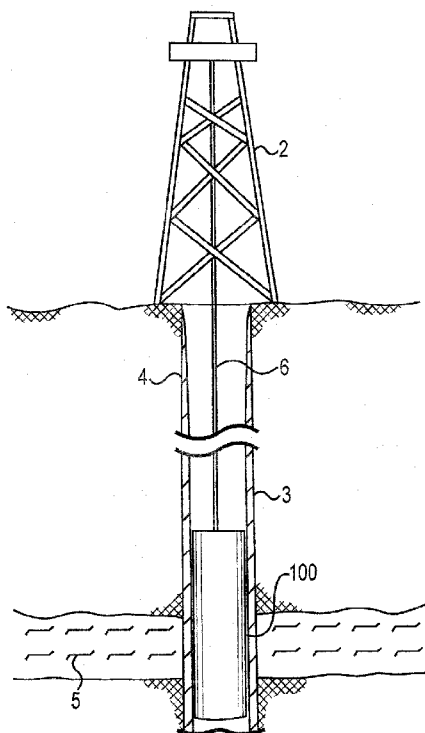


Fig. 7



- (71) **Applicant** (for CA only): **SCHLUMBERGER CANADA LIMITED** [CA/CA]; 525-3rd Avenue South-west, Calgary, Alberta T2P-0G4 (CA).
- (71) **Applicant** (for all designated States except AL, AM, AT, AU, AZ, BG, BN, BY, CA, CH, CL, CO, CY, CZ, DE, DK, EG, FR, GB, GE, GR, HR, HU, ID, IE, IL, IT, JP, KE, KG, KP, KR, KZ, LT, MG, MX, MY, NL, NO, NZ, OM, PL, QA, RO, RU, SI, SK, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, ZA): **PRAD RESEARCH AND DEVELOPMENT LIMITED**; P.O. Box 71, Craigmuir Chambers, Tortola, Road Town, 1110 (VG).
- (71) **Applicant** (for US only): **SCHLUMBERGER TECHNOLOGY CORPORATION** [US/US]; 300 Schlumberger Drive, Sugar Land, Texas 77478 (US).
- (72) **Inventor**: **MANIN, Yves**; Etudes et Productions Schlumberger, 1 rue Henri Becquerel, BP 202, F-92142 Clamart CEDEX (FR).
- (74) **Agents**: **CHI, Stephanie** et al; Schlumberger, IP Administration, 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, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LT, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

- (84) **Designated States** (unless otherwise indicated, for every kind of regional protection available): ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, 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, ML, MR, NE, SN, TD, TG).

Published:

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

SYSTEM AND METHOD FOR MEASURING FORMATION PROPERTIES

Technical Field

[0001] The disclosure pertains generally to the field of oil and gas exploration. More particularly, the disclosure relates to systems and methods for determining at least one property of a subsurface formation penetrated by a wellbore using a formation tester.

Background

[0002] Over the past several decades, highly sophisticated techniques have been developed for identifying and producing hydrocarbons, commonly referred to as oil and gas, from subsurface formations. These techniques facilitate the discovery, assessment, and production of hydrocarbons from subsurface formations.

[0003] When a subsurface formation containing an economically producible amount of hydrocarbons is believed to have been discovered, a borehole is typically drilled from the earth surface to the desired subsurface formation and tests are performed on the formation to determine whether the formation is likely to produce hydrocarbons of commercial value. These preliminary tests are conducted using formation testing tools, often referred to as formation testers. In some cases, formation testers are lowered into a wellbore by a wireline cable, tubing, drill string, or the like, and may be used to determine various formation characteristics which assist in determining the quality, quantity, and conditions of the hydrocarbons or other fluids located therein. Other formation testers may form part of a drilling tool, such as a drill string, for the measurement of formation parameters during the drilling process.

[0004] Formation testers are typically used to measure downhole parameters, such as wellbore pressures, formation pressures, and formation mobilities. The formation properties determined during a formation test are important factors in determining the commercial value of a well and the manner in which hydrocarbons may be recovered from the well.

[0005] Despite the advances made in developing methods for performing pretests, there remains a need to eliminate delays and errors in the pretest process, and to improve the accuracy of the parameters derived from such tests, particularly in formations with low mobility (e.g., less than 0.1 mD/cP).

Summary

[0006] In some embodiments, a method is provided. The method can include: a) creating a pressure reduction in a flowline in a formation tester, the flowline in fluid communication with a fluid having a pressure, b) measuring temperature change within the flowline as the fluid is drawn into the flowline, c) normalizing temperature change as measured in the flowline to temperature exterior to the formation tester ($\delta(\Delta T)$), d) measuring pressure change in the flowline (δP) as the fluid is drawn into the flowline, and e) determining whether a curve resulting from the equation $\delta P/\delta(\Delta T)$ over a period of time indicates that the pressure reduction reached a flowline pressure that is at or below the pressure of the fluid.

[0007] In some embodiments, the step of determining is done at substantially the same time as the measuring steps.

[0008] In some embodiments, the determining step comprises calculating a time integral of the curve, e.g., from the formula

$$f(n) = \alpha \cdot \sum_{i=v+1}^n \left| \frac{P_{i-v} - P_{i+v}}{\Delta T_{i-v} - \Delta T_{i+v}} \right|,$$

where P is flowline pressure, ΔT is flowline temperature normalized for temperature exterior to the flowline, i is the index of pressure and temperature measurement starting at $i=1$, v is a value defining a smoothing window over which individual pressure and temperature measurements are smoothed, n is the number indices i within the selected period of time, and α is an arbitrary scaling factor.

[0009] In some embodiments, the period of time is less than 2 minutes, from about 30 seconds to about 100 seconds, or about 40 seconds.

[0010] In some embodiments, the method can further include repeating steps a through e if the curve indicates that the pressure reduction did not reach a flowline pressure that is at or below the pressure of the fluid.

[0011] In some embodiments, a system is provided. The system can include: a) a formation tester having a flowline, the flowline in fluid communication with a fluid having a pressure and one or more sensor, the one or more sensor operable to measure temperature exterior to the formation tester and measure pressure and temperature within the flowline, b) a processor that receives temperature and pressure data from the one or more sensor and calculates a curve resulting from the equation $\delta P/\delta(\Delta T)$, where δP is pressure change in the

flowline as the fluid is drawn into the flowline by the creation of a first pressure reduction within the flowline, and where $\delta(\Delta T)$ is temperature change in the flowline normalized for temperature exterior to the flowline.

[0012] In some embodiments, the processor further calculates a time integral of the curve, e.g., from the formula

$$f(n) = \alpha \cdot \sum_{i=v+1}^n \left| \frac{P_{i-v} - P_{i+v}}{\Delta T_{i-v} - \Delta T_{i+v}} \right|$$

where P is flowline pressure, ΔT is flowline temperature normalized for temperature exterior to the flowline, i is the index of pressure and temperature measurement starting at $i=1$, v is a value defining a smoothing window over which individual pressure and temperature measurements are smoothed, n is the number indices i within the selected period of time, and α is an arbitrary scaling factor.

[0013] In some embodiments, the processor further indicates whether the first pressure reduction reached a flowline pressure that is at or below the pressure of the fluid.

[0014] In some embodiments, the processor further initiates creation of a second pressure reduction in the flowline if the curve from step c indicates that the first pressure reduction did not reach a flowline pressure that is at or below the pressure of the fluid.

[0015] While multiple embodiments with multiple elements are disclosed, still other embodiments and elements of the present invention will become apparent to those skilled in the art from the following detailed description, which shows and describes illustrative embodiments of the invention. Accordingly, the drawings and detailed description are to be regarded as illustrative in nature and not restrictive.

Brief Description of the Figures

[0016] Figure 1 is a schematic diagram of a wireline formation tester in accordance with an embodiment of the disclosure.

[0017] Figure 2 is a cross sectional view of a modular wireline formation tester in accordance with an embodiment of the disclosure.

[0018] Figure 3 is a graphical representation of an example of flowline pressure readings over time.

[0019] Figure 4 is a graphical representation of example flowline pressure readings from a series of drawdowns (A, C, E, G) and buildups (B, D, F, H).

[0020] Figure 5A is a graphical representation of an example of the relationship between pressure and temperature over time in a flowline following a drawdown that reaches a pressure at or below that of a fluid in a formation in which a well formation tester is disposed.

[0021] Figure 5B is a graphical representation of an example of the relationship between pressure and temperature over time in a flowline following a drawdown that does not reach a pressure that is at or below that of a fluid in a formation in which a well formation tester is disposed.

[0022] Figure 6A is a graphical representation of an example of a curve plotting change in buildup pressure over change in temperature over time following a drawdown that reaches a pressure at or below that of a fluid in a formation in which a well formation tester is disposed.

[0023] Figure 6B is a graphical representation of an example of a slope of a curve plotting the change in buildup pressure over change in temperature over time following a drawdown that does not reach a pressure at or below that of fluid in a formation in which a well formation tester is disposed.

[0024] Figure 7 is a flow chart illustrating a method in accordance with an embodiment of the disclosure.

[0025] Figure 8A is a graphical representation of an example of flowline pressure and temperature readings from a series of paired drawdowns and buildups (1, 2, 3).

[0026] Figure 8B is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 1 of Fig. 7A.

[0027] Figure 8C is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 2 of Fig. 7A.

[0028] Figure 8D is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 3 of Fig. 7A.

[0029] Figure 9A is a graphical representation of an example of flowline pressure and temperature readings from a series of paired drawdowns and buildups (1, 2, 3).

[0030] Figure 9B is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 1 of Fig. 8A.

[0031] Figure 9C is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 2 of Fig. 8A.

[0032] Figure 9D is a graphical representation of a time integral curve calculated

from the pressure and temperature readings of buildup 3 of Fig. 8A.

[0033] Figure 10A is a graphical representation of an example of flowline pressure and temperature readings from a series of paired drawdowns and buildups (1, 2, 3, 4).

[0034] Figure 10B is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 1 of Fig. 9A.

[0035] Figure 10C is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 2 of Fig. 9A.

[0036] Figure 10D is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 3 of Fig. 9A.

[0037] Figure 10E is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 4 of Fig. 9A.

[0038] Figure 11A is a graphical representation of an example of flowline pressure and temperature readings from a series of paired drawdowns and buildups (1, 2, 3).

[0039] Figure 11B is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 1 of Fig. 10A.

[0040] Figure 11C is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 2 of Fig. 10A.

[0041] Figure 11D is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 3 of Fig. 10A.

[0042] Figure 12A is a graphical representation of an example of flowline pressure and temperature readings from a series of paired drawdowns and buildups (1, 2).

[0043] Figure 12B is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 1 of Fig. 11A.

[0044] Figure 12C is a graphical representation of a time integral curve calculated from the pressure and temperature readings of buildup 2 of Fig. 11A.

[0045] Figure 13 is a schematic block diagram depicting a computing apparatus in accordance with an embodiment of the disclosure

Detailed Description

[0046] One or more specific embodiments of the present disclosure will be described below including method, apparatus and system embodiments. These described embodiments and their various elements are only examples of the presently disclosed techniques. It should be appreciated that in the development of any such actual implementation, as in any

engineering or design project, numerous implementation- specific decisions can be made to achieve the developers' specific goals, such as compliance with system-related and business-related constraints, which can vary from one implementation to another. Moreover, it should be appreciated that such a development effort might be time consuming, but would nevertheless be a routine undertaking of design, fabrication, and manufacture for those of ordinary skill having the benefit(s) of this disclosure.

[0047] When introducing elements of various embodiments of the present disclosure, the articles "a," "an," and "the" 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 can be additional elements other than the listed elements. Additionally, it should be understood that references to "one embodiment" or "an embodiment" of the present disclosure are not intended to be interpreted as excluding the existence of additional embodiments that also incorporate the listed elements.

[0048] Figure 1 illustrates an embodiment of a wireline formation testing apparatus, system, and methodology. The wireline formation testing system of Figure 1 can be onshore or offshore for, for example, exploring oil, natural gas, and other resources that can be used, refined, and otherwise processed for fuel, raw materials and other purposes. In the wireline formation testing system of Figure 1, a borehole 3 can be formed in subsurface formations 5, such as rock formations, by rotary drilling using any suitable technique. A wireline tester 100 can be lowered using a wireline cable 6 into the open borehole 3 lined with mudcake 4 deposited onto the wall of the wellbore during drilling operations. A surface system of the wireline formation testing system of Figure 1 can include a platform and derrick assembly 2 positioned over the borehole 3.

[0049] Any suitable wireline tester can be used to perform the methods provided herein. Figure 2 illustrates an embodiment of a wireline tester 100 suitable for use in the wireline formation testing system of Figure 1. The wireline tester 100 can include a probe 112 in fluid communication with the exterior of wireline tester 100 and a flowline 119 on the interior of the wireline tester 100. The wireline tester 100 can further include a piston 118 within a pretest chamber 114 in fluid communication with flowline 119 and a pressure sensor or gauge 120 (e.g., a sapphire or quartz pressure gauge) that measures pressure within flowline 119. In some embodiments, wireline tester 100 can include a temperature sensor or gauge (not shown) that measures temperature within flowline 119. In some embodiments, wireline tester 100 can include a temperature sensor or gauge (not shown) that measures

temperature of a fluid exterior to the tester 100 (e.g., a fluid in borehole 3). Each temperature or pressure sensor can have any appropriate sampling rate, which may or may not be adjustable. In some embodiments, the temperature and pressure sampling rates are the same.

[0050] Once wireline tester 100 is lowered to the desired position in borehole 3, fluid in the borehole can be allowed to enter the flowline 119, for example, by opening an equalization valve (not shown). An example of pressure measured in flowline 119 by pressure sensor 120 at this point is graphically depicted as line 103 in Figure 3. In some embodiments, the wireline tester 100 can be anchored in place and probe 112 can be positioned in fluid communication with a fluid in formation 5 using, for example, hydraulically-actuated pistons, and the interior of the wireline tester 100 can be isolated from the fluid in the borehole by closing the equalization valve. An example of a pressure measurement at the time of establishment of fluid communication of probe 112 with a fluid in formation 5 is graphically illustrated at 105 in Figure 3. A pressure reduction (also termed herein as a "drawdown phase") can then be created in flowline 119, for example, by retracting piston 118. An example of a pressure reduction in flowline 119 of a drawdown phase is graphically depicted as line 107 in Figure 3. In some embodiments, a fluid in fluid communication with flowline 119 (e.g., a fluid from formation 5) can then be drawn into flowline 119.

[0051] When piston 118 stops retracting, fluid (e.g., from formation 5) continues to enter probe 112, causing an increase in pressure (also termed herein as a "buildup phase") in flowline 119. An example of a pressure measured when piston 118 stops retracting is graphically depicted at 111 in Figure 3, while an example of a buildup phase pressure increase is depicted as line 113 in Figure 3. When probe 112 is disengaged from formation 5, as represented at point 115 of Figure 3, pressure in flowline 119 can equilibrate to a pressure that approximates the pressure of fluid in borehole 3, as graphically illustrated in Figure 3 as 117.

[0052] In some embodiments, temperature inside flowline 119 can be measured during all or part of one or more drawdown and/or buildup phases. In some embodiments, temperature exterior to wireline tester 100 (e.g., temperature of a fluid in borehole 3) can be measured during one or more drawdown and/or buildup phase.

[0053] In some embodiments, if a drawdown phase is performed that reaches a pressure at or below that of a fluid in formation 5, pressure in flowline 119 can equilibrate to a final pressure that is approximately the same as the pressure of a fluid in formation 5, as

graphically illustrated as line 115 in Figure 3. As used herein, a buildup phase that can be used to approximate a pressure of a fluid in a formation 5 is termed "genuine buildup." In some embodiments, where a drawdown phase does not reach a pressure at or below that of a fluid in formation 5, a subsequent buildup phase pressure increase can be due to temperature and pressure equalization following adiabatic cooling within flowline 119 when a pressure reduction is created by piston 118. In such embodiments, a pressure measured in flowline 119 is not representative of a pressure of a fluid in formation 5, and is termed herein a "pseudo buildup."

[0054] In some embodiments, the steps of creating a pressure reduction and measuring pressure in flowline 119 can be repeated until a drawdown phase reaches a pressure at or below that of a fluid in formation 5, such that a subsequent buildup phase can be used to approximate a pressure of a fluid in formation 5. Figure 4 graphically illustrates an example of pressure measurements over multiple cycles of drawdown phases A, C, E, G and buildup phases B, D, F, H performed over time. In some embodiments, cycles of drawdown and buildup phases can be repeated until two or more repeatable buildup phases are achieved, where each of the repeatable buildup phases reaches approximately the same pressure (e.g., within the margin of pressure gauge or sensor sensitivity), as illustrated with buildup phases F and H in Figure 4. Drawdown phases E and G, then, can be identified as having reached a pressure at or below that of a fluid in formation 5, and pressure of formation 5 can be determined as approximately equivalent to the final pressure in flowline 119 during one or more of the repeatable buildup phases.

[0055] As provided herein, a drawdown phase can be predicted as having reached a pressure that is at or below the pressure of a fluid in a formation 5 prior to performing another drawdown phase by predicting whether a subsequent buildup phase is a genuine buildup (i.e., the drawdown phase had reached a pressure that is at or below that of a fluid in formation 5) or a pseudo buildup (i.e., the drawdown phase had not reached a pressure that is at or below that of a fluid in formation 5). As shown in Figure 7, a method 1000 for predicting whether a drawdown phase has reached a pressure that is at or below the pressure of a fluid in fluid communication with a flowline can include, after creating a pressure reduction in the flowline 1050, measuring temperature within the flowline as fluid is drawn into the flowline 1052, measuring pressure within the flowline as fluid is drawn into the flowline 1056, and determining whether a curve based on the ratio of pressure change to temperature change indicates that the pressure reduction reached a pressure that is at or below that of a fluid in

fluid communication with the flowline 1058. Pressure increase in flowline 119 over a period of time in a genuine buildup can be observed to diverge from temperature increase in flowline 119 over the same period of time, as illustrated in the example shown in Figure 5A. As illustrated in Figure 5B, pressure increase in flowline 119 over a period of time in a pseudo buildup can be observed to trend closely with temperature increase in flowline 119 over the same period of time.

[0056] In some embodiments, a curve can be calculated from the ratio of change in pressure (δP) over change in temperature (δT) in flowline 119 over a period of time. A buildup phase can be predicted as more likely to be genuine as the curvature resulting from the equation $\delta P/\delta T$ (Eq. 1) becomes greater. Conversely, a buildup phase can be predicted as more likely to be a pseudo buildup as the curvature of a curve resulting from Equation 1 becomes smaller.

[0057] In some embodiments, as shown in Figure 7, temperature in flowline 119 can be normalized to temperature of fluid exterior to formation tester 100 in order to take into account temperature changes that are not related to adiabatic cooling (e.g., a change in temperature of the borehole 3). A normalized temperature (ΔT) in flowline 119 can be calculated by subtracting temperature measured in fluid exterior (e.g., fluid in borehole 3) to the formation tester 100 from temperature measured in the flowline 119 at each measured time point. A curve resulting from the equation $\delta P/\delta(\Delta T)$ (Eq. 2) over a period of time can then be calculated. As illustrated in the example shown in Figure 6A, a buildup phase can be predicted as more likely to be genuine as the curvature resulting from Equation 2 becomes greater. Conversely, as shown in the example in Figure 6B, a buildup phase can be predicted as more likely to be a pseudo buildup as the curvature of a curve resulting from Equation 2 becomes smaller.

[0058] In some instances, temperature normalization can result in zero or negative values when differences between temperature within flowline 119 and temperature of fluid outside of the formation tester 100 are within sensor resolution. In some embodiments, normalized temperatures having zero or negative values can be avoided by using various methods of data conditioning. For example, normalized temperatures having zero or negative values can be avoided by linearly interpolating values that are within sensor resolution. In some embodiments, values that are within sensor resolution (z) can be linearly interpolated for $z=1,n$ using Equation 3:

$$\text{If } T_{(i-1)+z} < 0$$

$$T'_{(i)} = T_{(i-1)} + \frac{T_{(i+n)} - T_{(i-1)}}{(n+1)} \quad (\text{Eq. 3})$$

where $T_{(i)}$ is the temperature measurement at index i , n is the number indices i following $i=1$ over which temperature is interpolated, and $T'_{(i)}$ is the linearly interpolated temperature.

[0059] In some embodiments, pressure values within sensor resolution (e.g., about 0.2 psi when using a sapphire gauge) can be linearly interpolated using methods similar to those used to linearly interpolate temperature.

[0060] In some embodiments, a time integral of a curve calculated from Equation 1 or Equation 2 can be used to predict whether a buildup is a genuine buildup or a pseudo buildup. For example, in some embodiments, a time integral calculated using Equation 4:

$$f(n) = \alpha \cdot \sum_{i=v+1}^n \left| \frac{P_{i-v} - P_{i+v}}{\Delta T_{i-v} - \Delta T_{i+v}} \right| \quad (\text{Eq. 4})$$

where P is flowline pressure and ΔT is flowline temperature normalized for temperature of a fluid exterior to the flowline. The variables i , v , n , and α are discussed below.

[0061] Variable i in Equation 4 is a whole number representing the index of the current pressure and temperature measurements are taken. For example, for a sampling rate of 0.3 seconds, the first index $i=1$ represents the first pressure and temperature measurements taken 0.3 seconds after the start of the buildup, while the tenth index $i=10$ represents the tenth temperature and pressure measurements taken 3 seconds after the start of the buildup.

[0062] Variable n in Equation 4 is the number of indices within a selected period of time following a drawdown phase. For example, with a sampling rate of 0.3 seconds, at 30 seconds, $n=100$.

[0063] Variable v in Equation 4 is an value that defines a smoothing window over which individual pressure and temperature measurements are smoothed. Any appropriate value can be used for v . For example, if individual pressure and temperature measurements are to be smoothed over a window of 5 measurements before and 5 measurements after each individual measurement, then the value of v would be 5. In some embodiments, a value for v can be chosen based on a desired smoothing effect that can be provided by the smoothing window defined by v . In some embodiments, v can have a value of at least 3 (e.g., 3, 4, 5, 6, 7, 8, 9, and the like). In some embodiments, individual pressure and temperature measurements are not centered within a smoothing window. For example, each individual measurement can be smoothed over a window of 4 measurements before and 3 measurements

after the individual measurement. In such an embodiment, variable v can have multiple values as appropriate to define the desired window.

[0064] Variable a in Equation 4 is an arbitrary scaling factor. Any desired value for a can be chosen to provide a convenient graphical representation of values calculated from Equation 4. An appropriate value for a can depend on, for example, a period of time over which temperature and pressure are measured, a pressure or temperature sampling rate, a sensor resolution, or a desired range of values calculated from Equation 4.

[0065] The period of time over which a time integral of a curve is calculated can be any appropriate period of time. For example, in some embodiments, an appropriate period of time is less than 2 minutes. In some embodiments, an appropriate period of time is from about 20 seconds to about 100 seconds (e.g., from about 30 seconds to about 100 seconds, from about 30 to about 60 seconds, from about 40 to about 60 seconds, from about 45 to about 80 seconds, 35 seconds, 40 seconds, 50 seconds, 60 seconds, 75 seconds, 90 seconds, or the like). The period of time over which a time integral of a curve is calculated can be adjusted to account for various conditions, such as mobility of a fluid for which pressure will be estimated, pressure and/or temperature gauge sensitivity, the volume of the flowline, and the like.

[0066] In some embodiments, a threshold value calculated from Equation 4 at a selected time point can be identified as being predictive of whether a drawdown phase has reached a pressure that is at or below that of a fluid in communication with flowline 119. For example, in some embodiments, for a sampling rate of 0.3 seconds using $a=0.0001$, a value calculated at 40 seconds from Equation 4 that is greater than 10 during a 40 second period of time indicates that a buildup phase is a genuine buildup and/or that the previous drawdown phase had reached a pressure that is at or below that of a fluid in communication with flowline 119. Conversely, in the same example, a value calculated at 40 seconds from Equation 4 that is less than 10 indicates that the buildup phase is a pseudo buildup and/or that the previous drawdown phase had not reached a pressure that is at or below that of a fluid in communication with flowline 119. In some embodiments, a buildup that has been calculated to be a pseudo buildup can indicate that a fluid in communication with flowline 119 is not flowing into flowline 119.

[0067] Figures 8A, 9A, 10A, 11A, and 12A illustrate examples of time integral curves from various drawdown and buildup sets. Each of the curves are calculated using Figures 8B, 9B, 10B, 10C, 11B, 11C, and 12B and are graphical representations of curves calculated

from Equation 4 using a sampling rate of 0.3 seconds, $a=0.0001$, and pressure and normalized temperature data from buildup 1 of Figure 8A, buildup 1 of Figure 9A, buildup 1 of Figure 10A, buildup 2 of Figure 10A, buildup 1 of Figure 11A, buildup 2 of Figure 11A, and buildup 1 of Figure 12A, respectively. Each of the curves from 8B, 9B, 10B, 10C, 11B, 11C, and 112B indicate a pseudo buildup.

[0068] Figures 8C, 8D, 9C, 9D, 10D, 10E, 11D, and 12C are graphical representations of time integral curves calculated from Equation 4 using a sampling rate of 0.3 seconds, $a=0.0001$, and pressure and normalized temperature data from buildup 2 of Figure 8A, buildup 3 of Figure 8A, buildup 2 of Figure 9A, buildup 3 of Figure 9A, buildup 3 of Figure 10A, buildup 4 of Figure 10A, buildup 3 of Figure 11A, and buildup 2 of Figure 12A, respectively. Each of the curves from 8C, 8D, 9C, 9D, 10D, 10E, 11D, and 12C indicate a genuine buildup.

[0069] In some embodiments, as illustrated in Figure 13, a computing apparatus 2000 can be used to calculate whether a drawdown phase had reached a pressure that is at or below that of a fluid exterior to formation tester 2300. According to various embodiments, the computing apparatus 2000 can include any type of computing device suitable for implementing embodiments of the subject matter disclosed herein. Examples of computing devices include "workstations," "servers," "laptops," "desktops," "tablet computers," "hand-held devices," and the like. In some embodiments, the computing apparatus 2000 can include more than one computing device such as, for example, in a distributed computing environment, a networked environment, and the like.

[0070] In some embodiments, a computing apparatus 2000 comprises a processor 2100 and storage device 2200, the storage device 2200 comprising a program 2210 that directs the processor 2100 receive pressure and temperature data from a formation tester 2300 to calculate whether a drawdown phase has reached a pressure that is at or below that of a fluid in fluid communication with a flowline of the formation tester 2300 using, for example, any of Equations 1, 2, or 4. In some embodiments, the program 2210 can also direct the processor 2100 to linearly interpolate temperature data using, for example, Equation 3. In some embodiments, the program 2210 can also direct the processor 2100 to linearly interpolate pressure data. A computing apparatus 2000 can be configured to receive pressure and temperature data directly or indirectly from one or more pressure sensor 2310 and/or temperature sensor 2320. In some embodiments, pressure sensor 2310 and temperature sensor 2320 are a single combined sensor. In some embodiments, a computing apparatus

2000 can be configured to receive pressure and temperature data from a storage device (e.g., a storage device storing program 2210 or a different storage device) that has stored pressure and temperature data from one or more pressure and temperature sensor 2310, 2320.

[0071] In some embodiments, a computing apparatus 2000 can be configured to perform calculations at substantially the same time as the measurements are recorded by one or more temperature and/or pressure sensor 2310, 2320. By substantially the same time, it is meant that calculations could be made at the same time or not at the exact same time pressure and/or temperature measurements are made, such as milliseconds to seconds apart or shorter or longer periods of time (e.g., 0.001, 0.03, 0.1, 0.5, 1, 2, 5, 10 or more seconds apart) that do not significantly adversely affect the benefit of the apparatus or methodology. In some embodiments, a computing apparatus 2000 can be configured to perform calculations at a time point after pressure and temperature data points are recorded, for example, on a storage device.

[0072] In some embodiments, a computing apparatus 2000 further includes a display (not shown) on which the program 2210 can direct the processor 2100 to display a graphical representation of a curve calculated from Equation 1 or 2, or to display an indication of a calculation resulting from Equation 4. In some embodiments, a computing apparatus 2000 includes an indicator (not shown) that displays an indication as to whether a drawdown phase had reached a pressure that is at or below that of a fluid exterior to formation tester 2300.

[0073] In some embodiments, a computing apparatus 2000 can be configured to automatically initiate another drawdown phase if a calculation using Equation 1, 2, or 4 indicates a drawdown phase did not reach a pressure at or below a pressure of a fluid outside of formation tester 2300.

[0074] In some embodiments, a computing apparatus 2000 can include one or more additional component, such as a power supply 2400, input/output (I/O) port 2500, I/O component 2600, and the like, as appropriate for a desired configuration or to perform selected functions.

[0075] In some embodiments, components from computing apparatus 2000, such as processor 2100 and storage device 2200 storing program 2210 can be included in a system further comprising a formation tester that includes a flowline and one or more sensor operable to measure temperature of a fluid exterior to the formation tester and measure pressure and temperature within the flowline. In some embodiments, a system provided herein can include one or more additional components associated with formation testers

and/or computing apparatuses described herein.

[0076] The components of computing apparatus 2000 can be directly or indirectly connected using any appropriate means, such as, for example, one or more busses 2700.

[0077] As can be appreciated by those skilled in the art, the provided methods, software, and/or computing apparatuses can be used in geologic formations other than those containing oil, natural gas, or other petrochemicals.

[0078] Various modifications, additions and combinations can be made to the exemplary embodiments and their various features discussed without departing from the scope of the present invention. For example, while the embodiments described above refer to particular features, the scope of this invention also includes embodiments having different combinations of features and embodiments that do not include all of the above described features.

WE CLAIM:

1. A method comprising:
 - a. creating a pressure reduction in a flowline in a formation tester, the flowline in fluid communication with a fluid having a pressure;
 - b. measuring temperature change within the flowline as the fluid is drawn into the flowline;
 - c. normalizing temperature change as measured in the flowline to temperature exterior to the formation tester ($\delta(\Delta T)$);
 - d. measuring pressure change in the flowline (δP) as the fluid is drawn into the flowline; and
 - e. determining whether a curve resulting from the equation $\delta P / \delta(\Delta T)$ over a period of time indicates that the pressure reduction reached a flowline pressure that is at or below the pressure of the fluid.

2. The method of claim 1, wherein the step of determining is done at substantially the same time as the measuring steps.

3. The method of claim 1 or 2, wherein step e comprises calculating a time integral of the curve.

4. The method of claim 3, wherein the time integral is calculated from the formula

$$f(n) = \alpha \cdot \sum_{i=v+1}^n \left| \frac{P_{i-v} - P_{i+v}}{\Delta T_{i-v} - \Delta T_{i+v}} \right|,$$

where P is flowline pressure, ΔT is flowline temperature normalized for temperature exterior to the flowline, i is the index of pressure and temperature measurement starting at $i=1$, v is a value defining a smoothing window over which individual pressure and temperature measurements are smoothed, n is the number indices i within the selected period of time, and α is an arbitrary scaling factor.

5. The method of any of claims 1-4, wherein the period of time is less than 2 minutes, from about 30 seconds to about 100 seconds, or about 40 seconds.

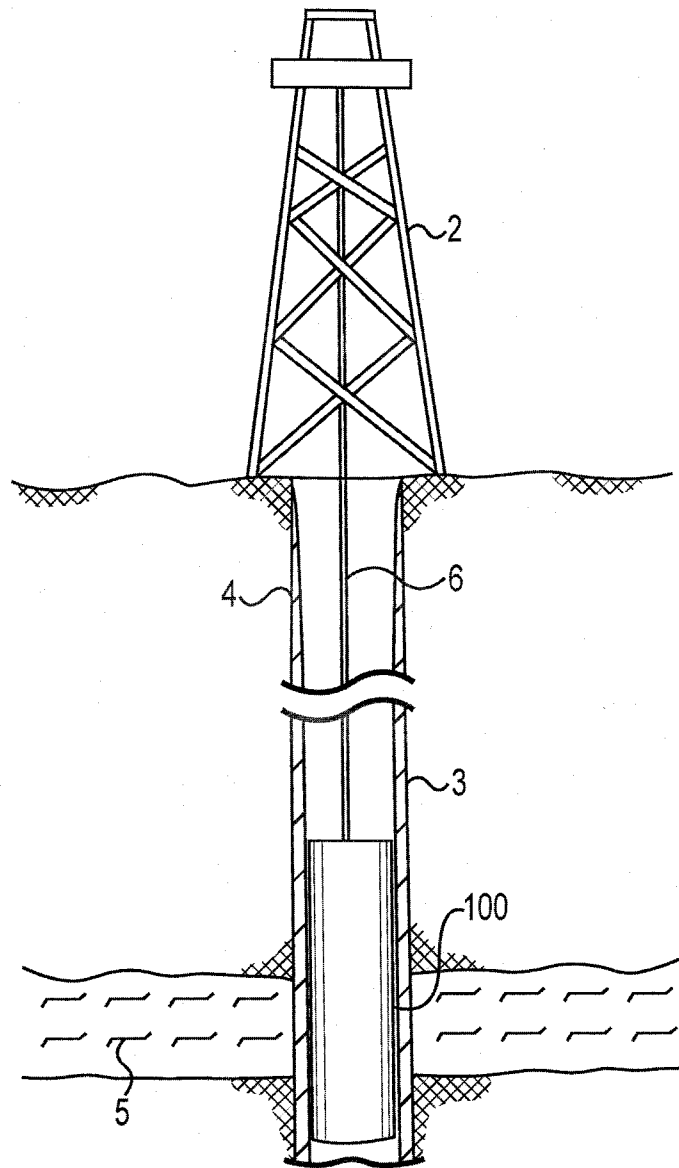
6. The method of any of claims 1-5, further comprising repeating steps a through e if the curve indicates that the pressure reduction did not reach a flowline pressure that is at or below the pressure of the fluid.
7. A system comprising:
 - a. formation tester having:
 - i. a flowline, the flowline in fluid communication with a fluid having a pressure; and
 - ii. one or more sensors, the one or more sensors operable to measure temperature exterior to the formation tester and measure pressure and temperature within the flowline; and
 - b. a processor that:
 - i. receives temperature and pressure data from the one or more sensors; and
 - ii. calculates a curve resulting from the equation $\delta P / \delta(\Delta T)$, where δP is pressure change in the flowline as the fluid is drawn into the flowline by the creation of a first pressure reduction within the flowline, and where $\delta(\Delta T)$ is temperature change in the flowline normalized for temperature exterior to the flowline.
8. The system of claim 7, wherein the processor further calculates a time integral of the curve.
9. The system of claim 8, wherein the time integral is calculated from the formula

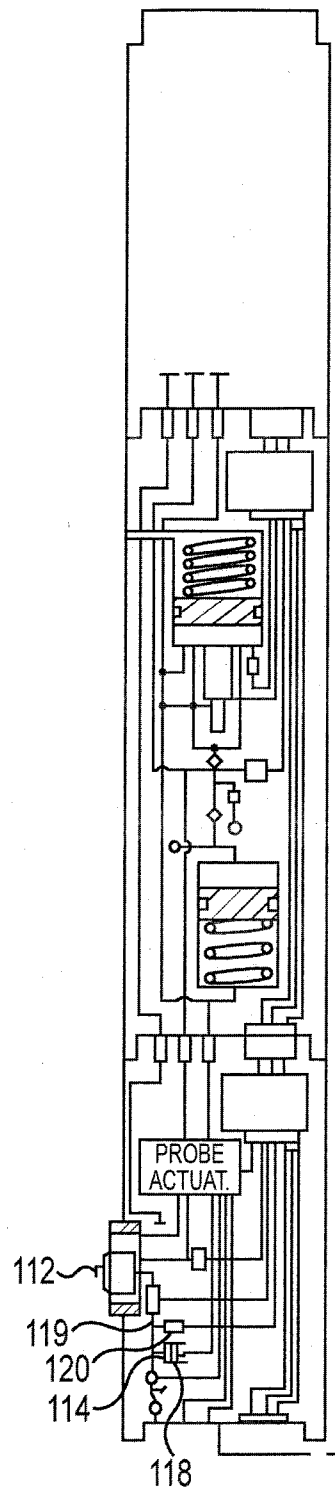
$$f(n) = \alpha \cdot \sum_{i=v+1}^n \left| \frac{P_{i-v} - P_{i+v}}{\Delta T_{i-v} - \Delta T_{i+v}} \right|$$

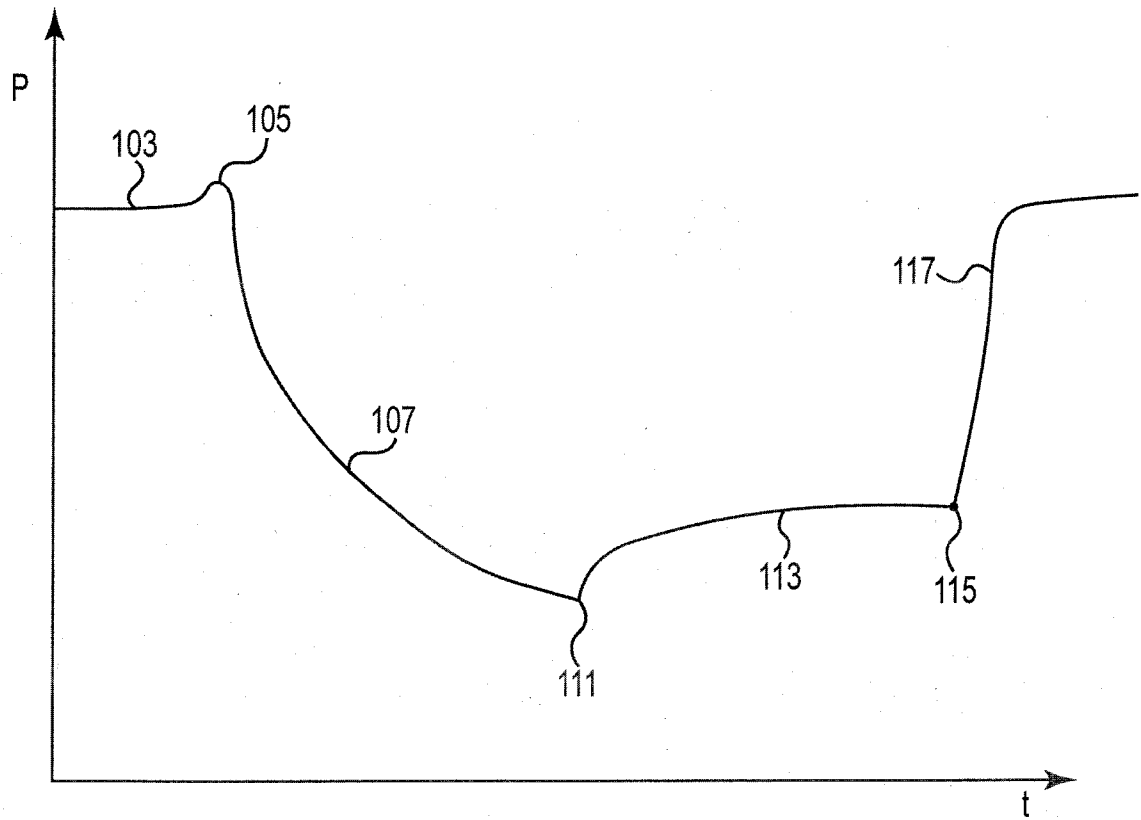
where P is flowline pressure, ΔT is flowline temperature normalized for temperature exterior to the flowline, i is the index of pressure and temperature measurement starting at $i=1$, v is a value defining a smoothing window over which individual pressure and temperature measurements are smoothed, n is

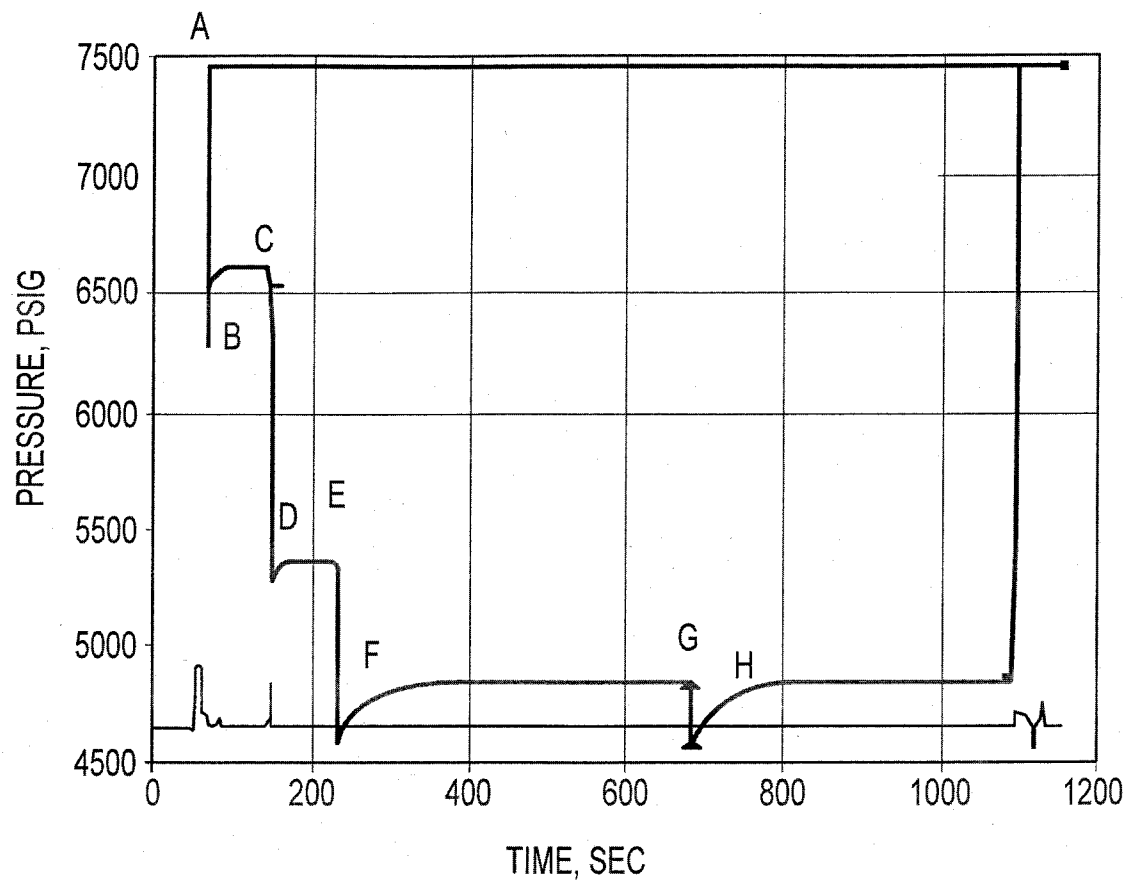
the number indices i within the selected period of time, and a is an arbitrary scaling factor.

10. The system of any of claims 7-9, wherein the processor further indicates whether the first pressure reduction reached a flowline pressure that is at or below the pressure of the fluid.
11. The system of any of claims 7-10, wherein the processor further initiates creation of a second pressure reduction in the flowline if the calculated curve indicates that the first pressure reduction did not reach a flowline pressure that is at or below the pressure of the fluid.

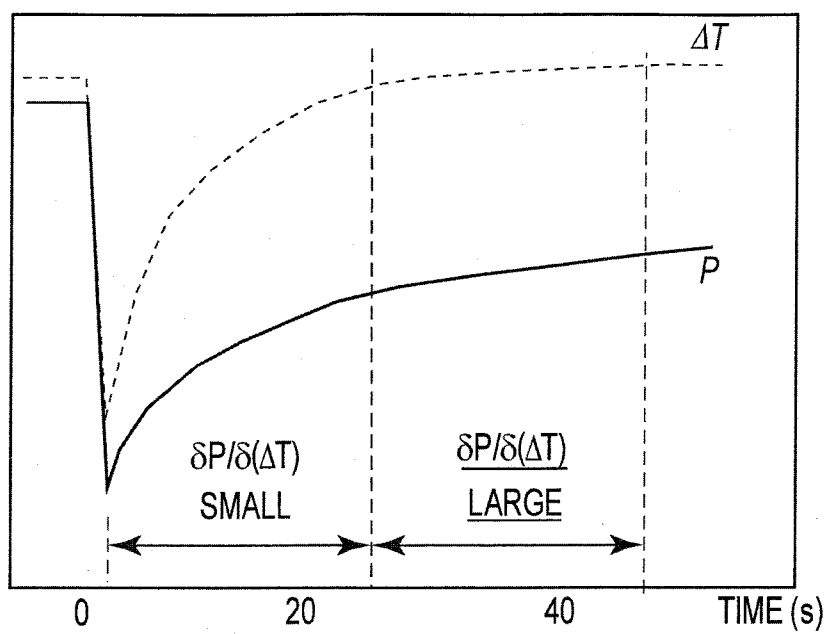
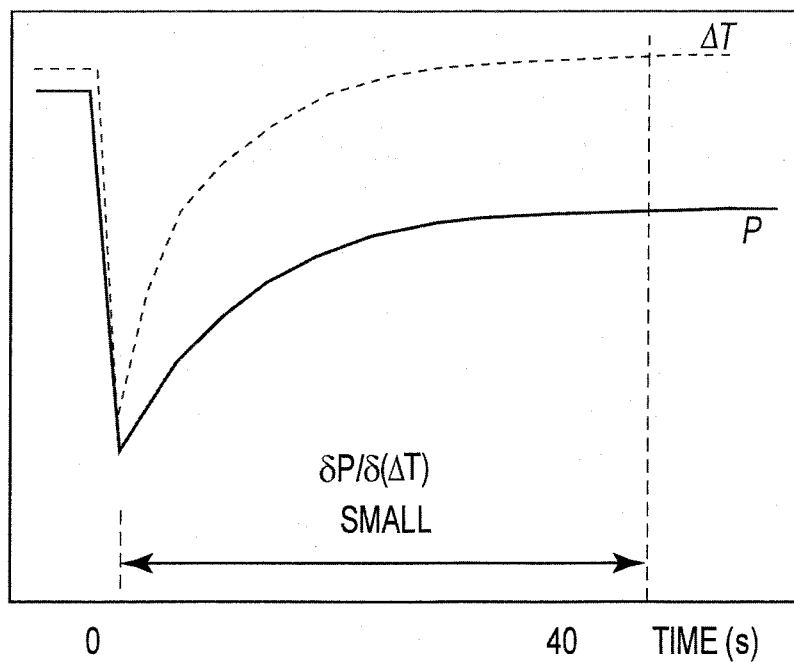
*Fig. 1*

*Fig. 2*

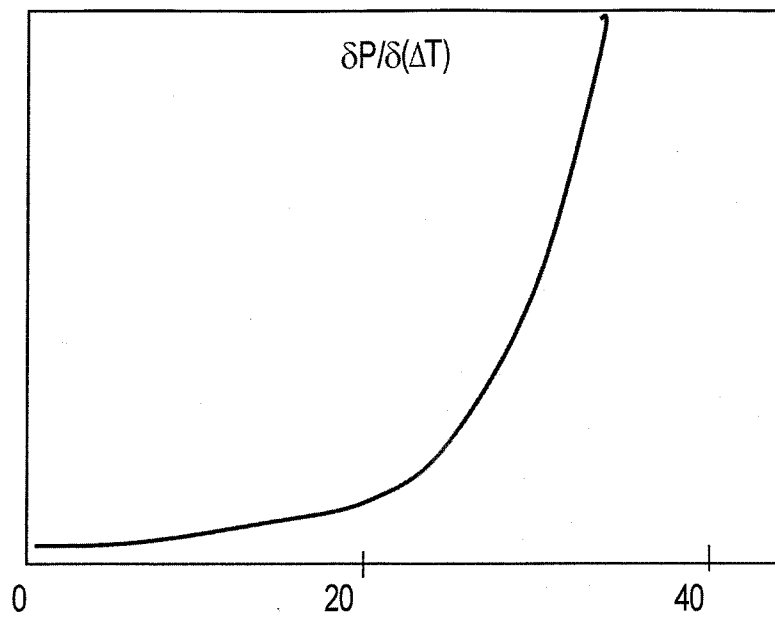
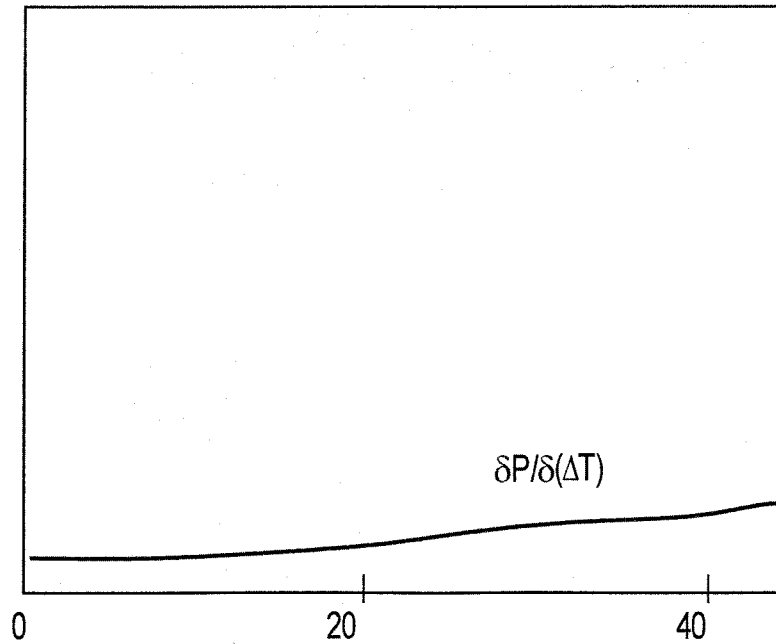
*Fig. 3*

*Fig. 4*

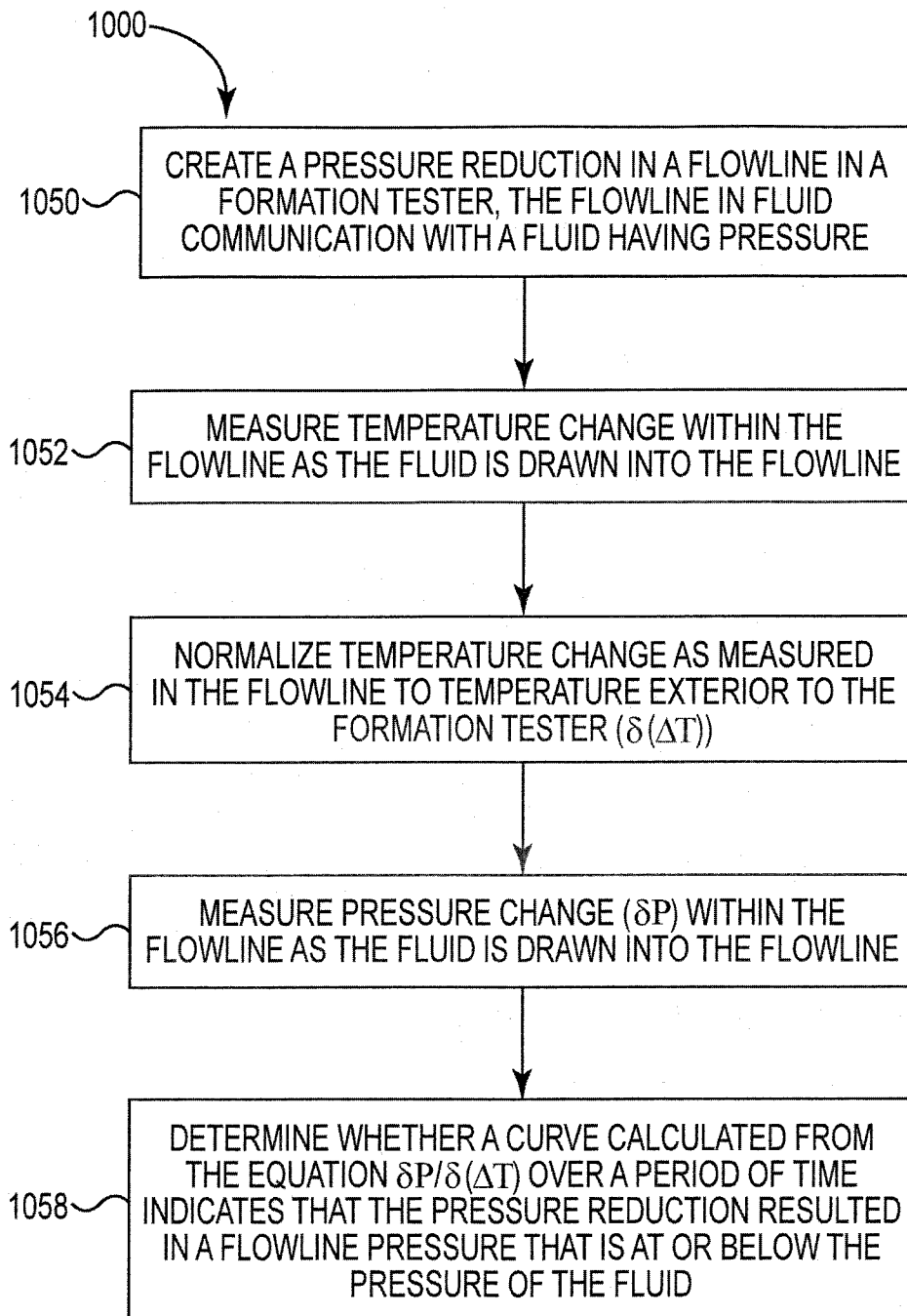
5/22

*Fig. 5A**Fig. 5B*

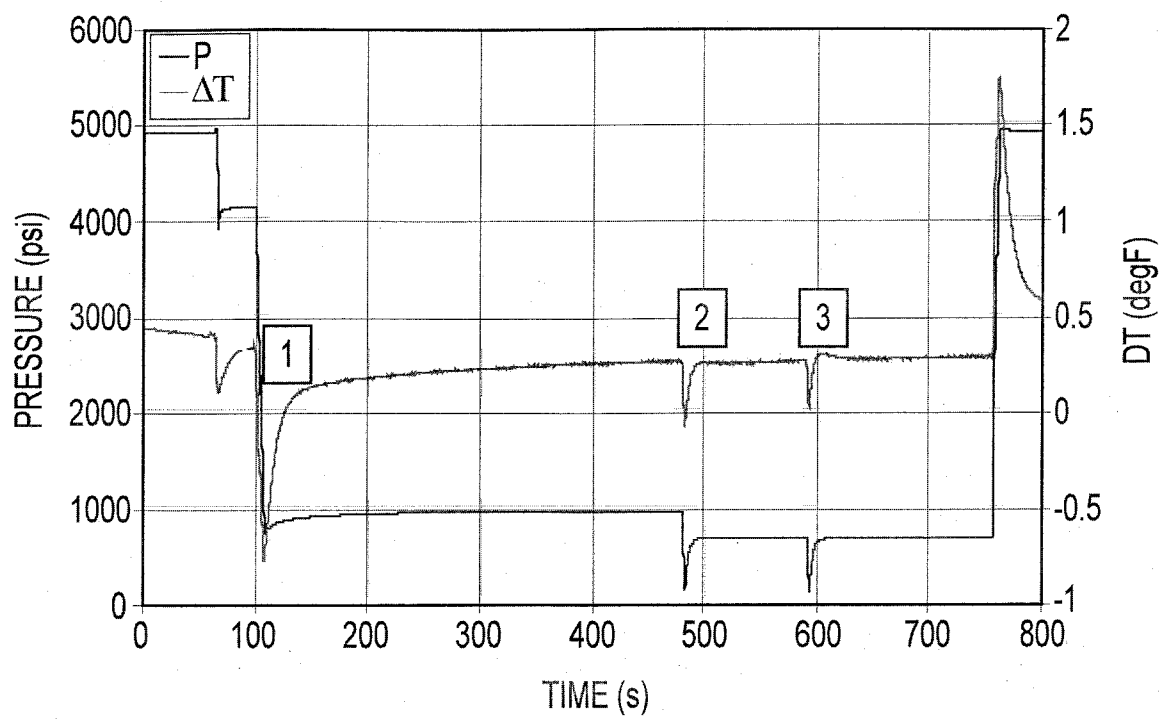
6/22

*Fig. 6A**Fig. 6B*

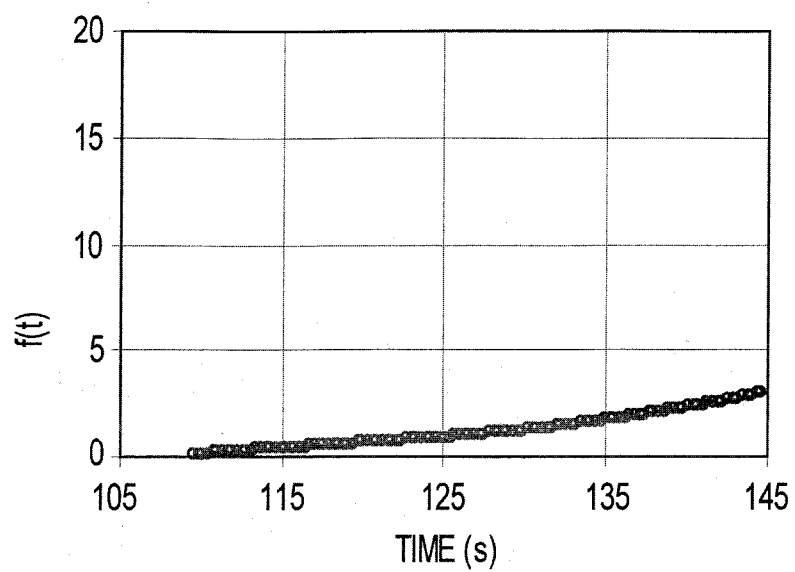
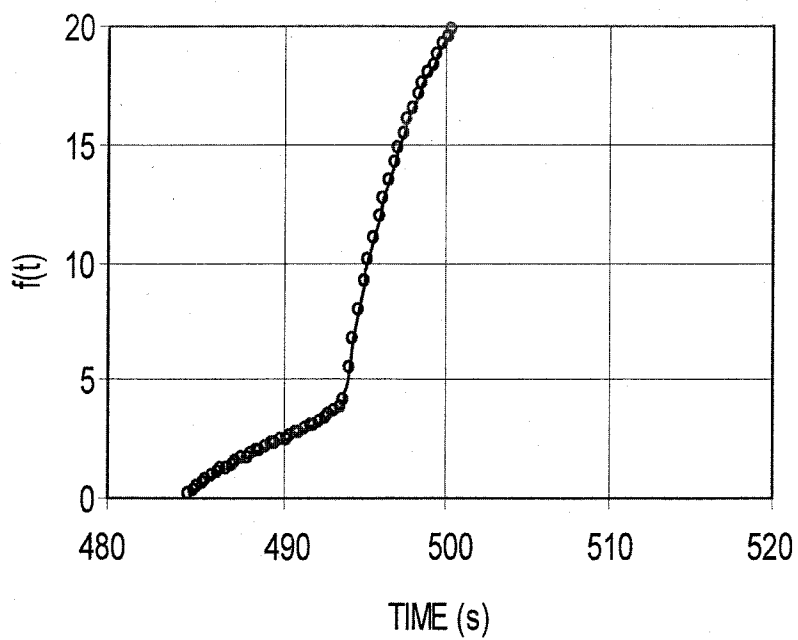
7/22

*Fig. 7*

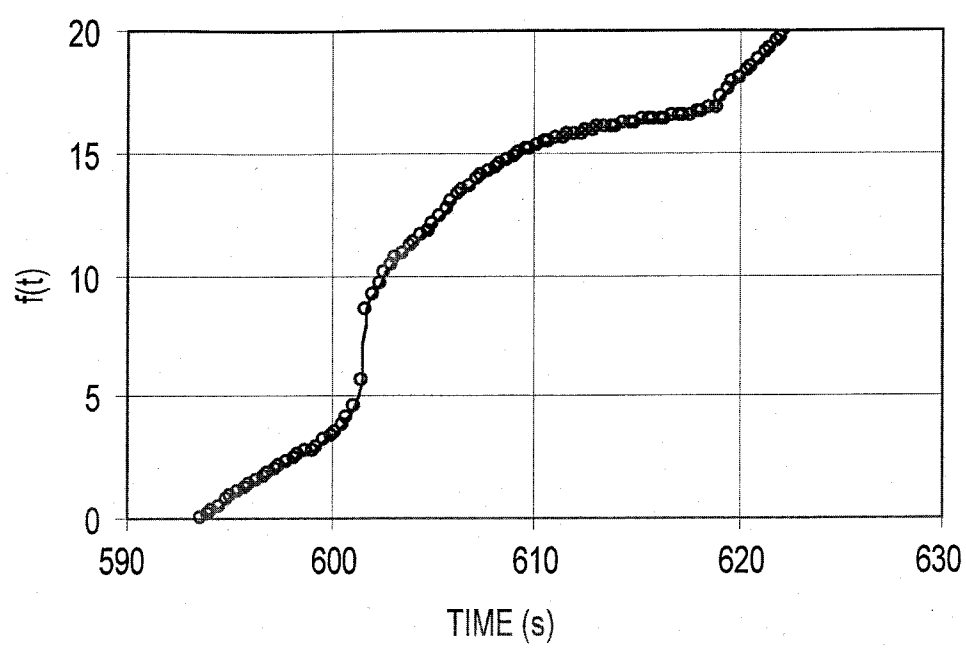
8/22

*Fig. 8A*

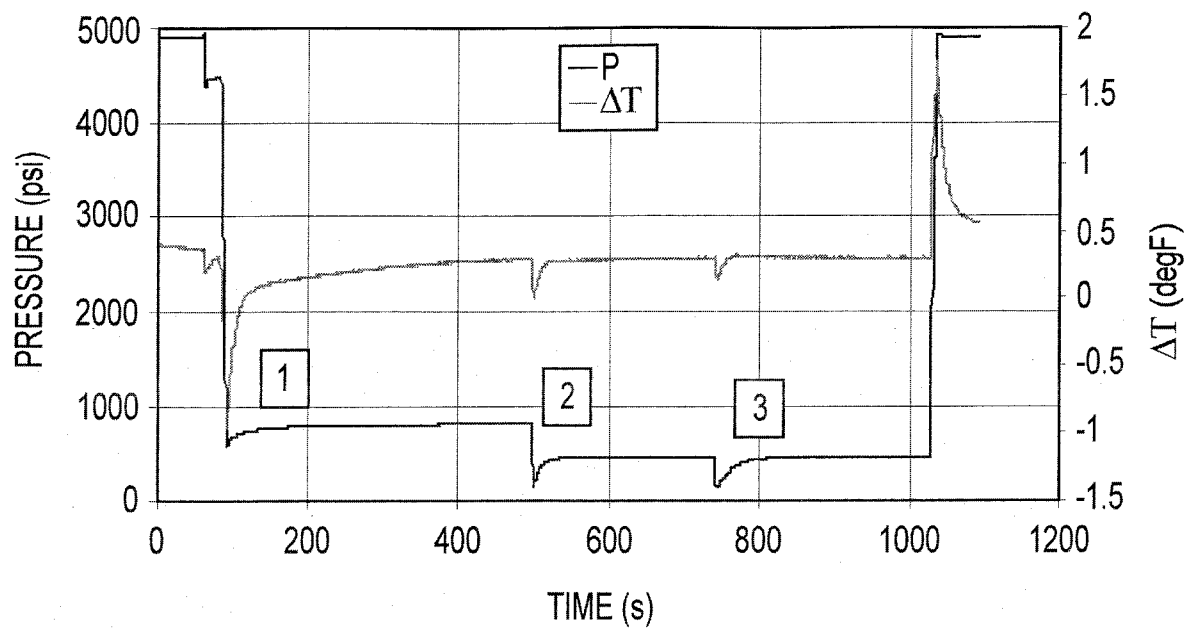
9/22

*Fig. 8B**Fig. 8C*

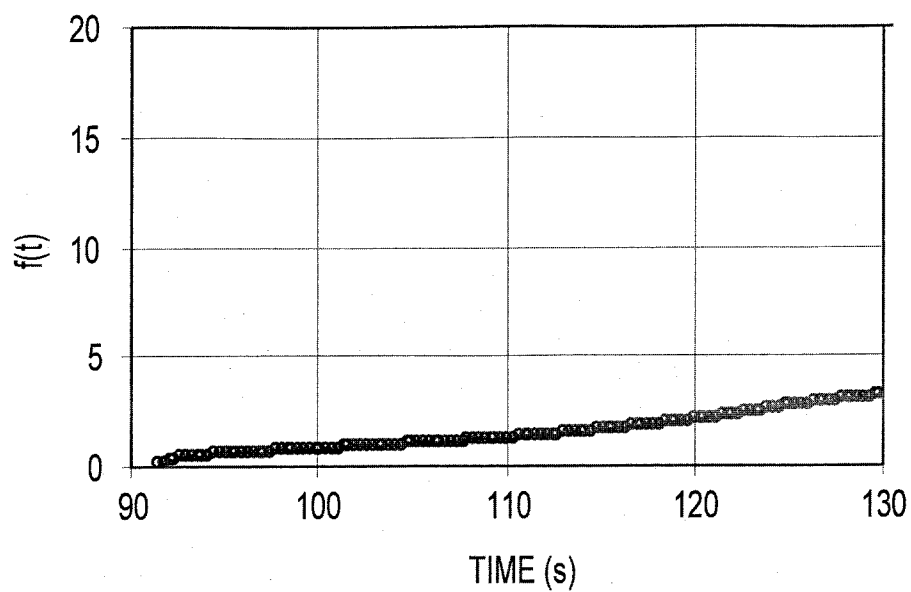
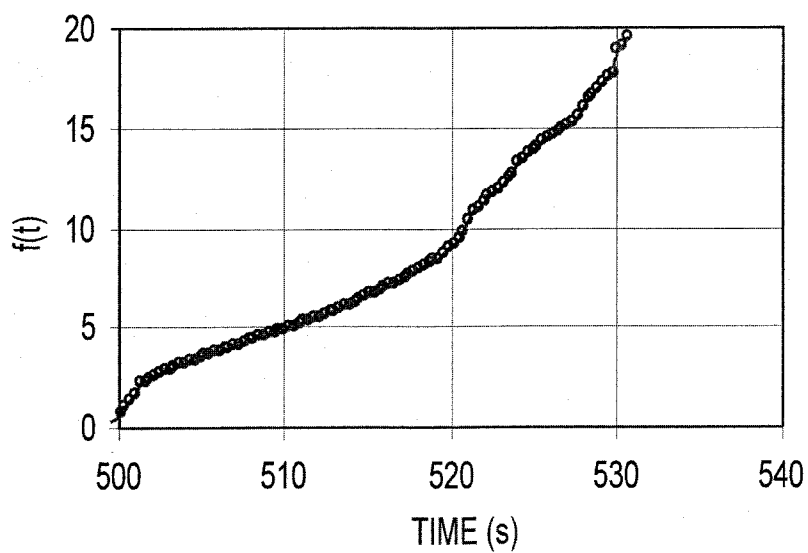
10/22

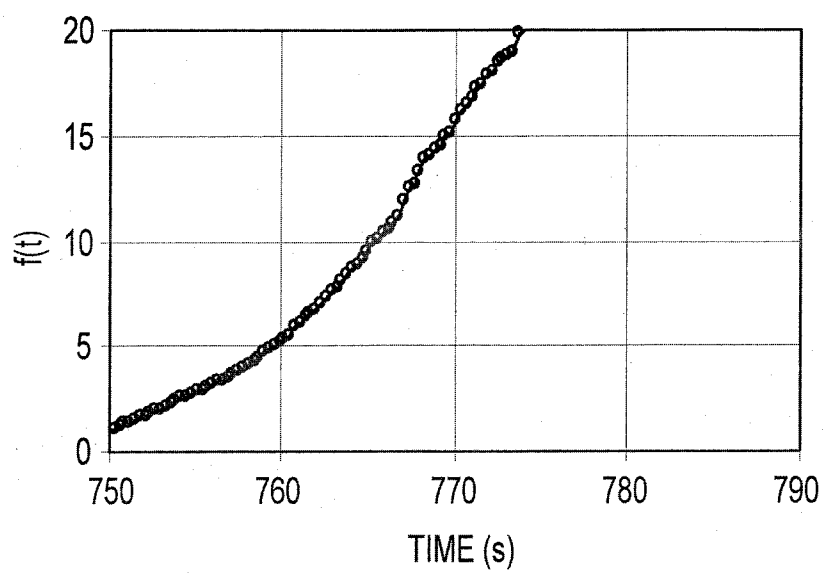
*Fig. 8D*

11/22

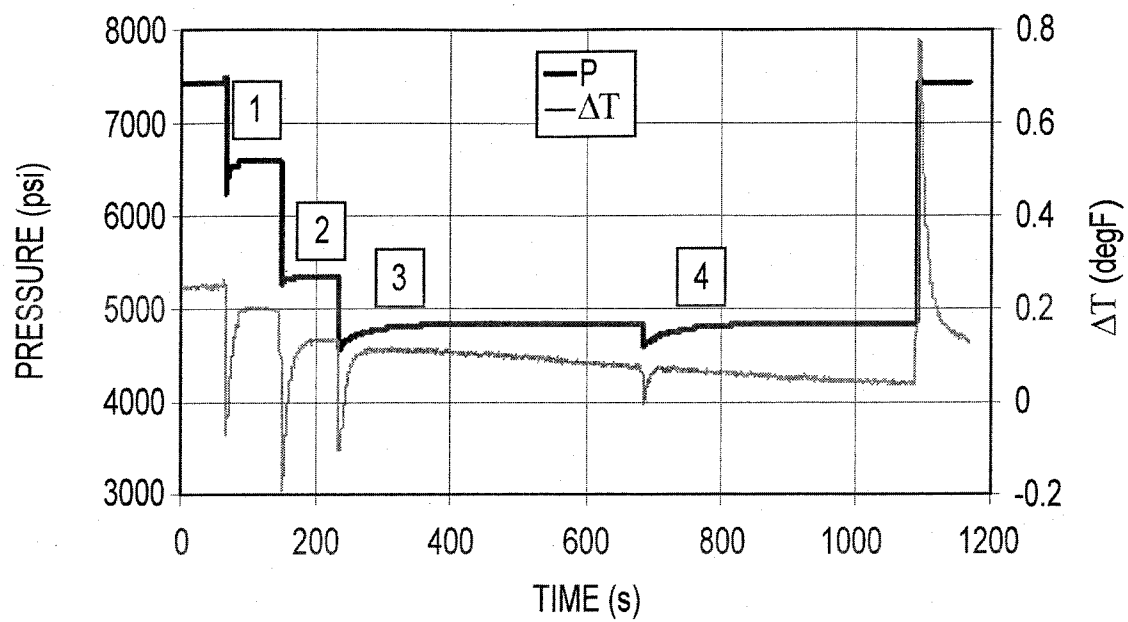
*Fig. 9A*

12/22

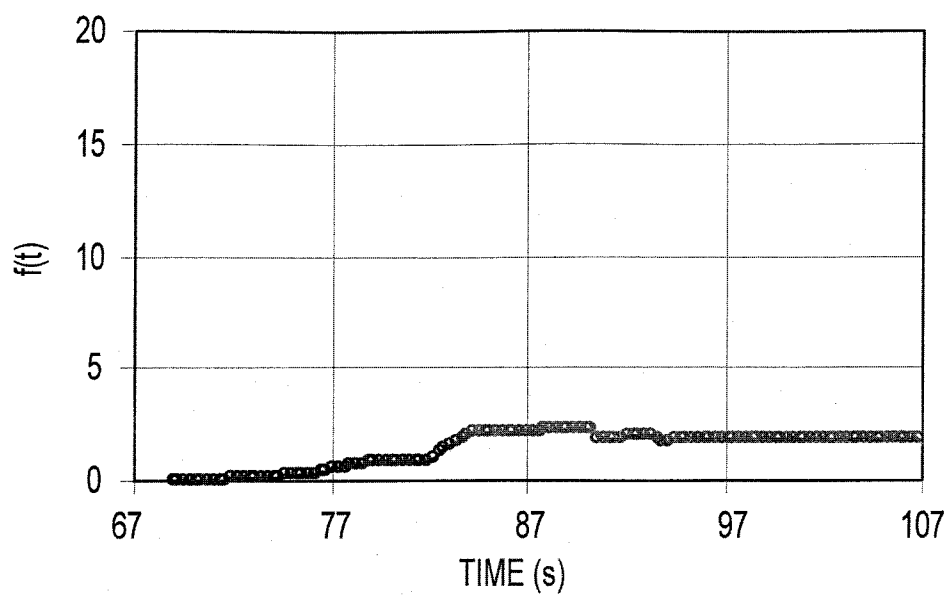
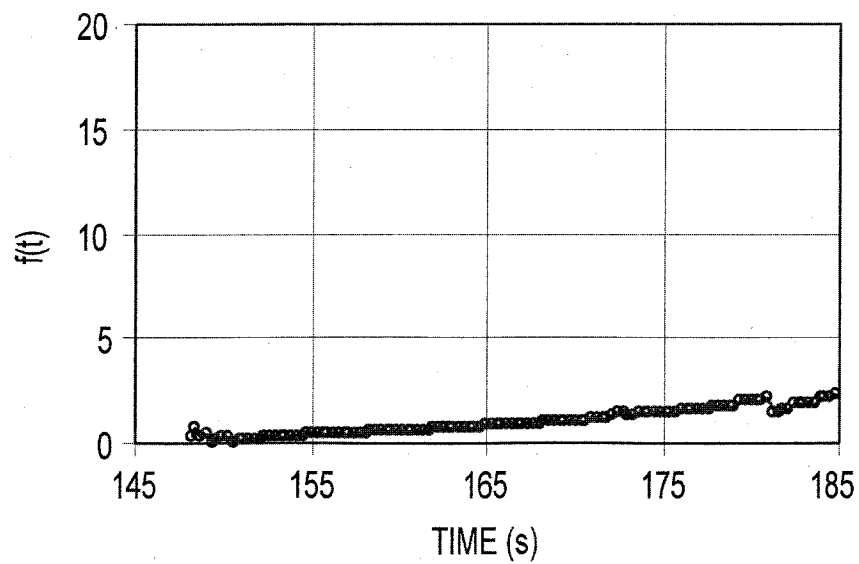
*Fig. 9B**Fig. 9C*

*Fig. 9D*

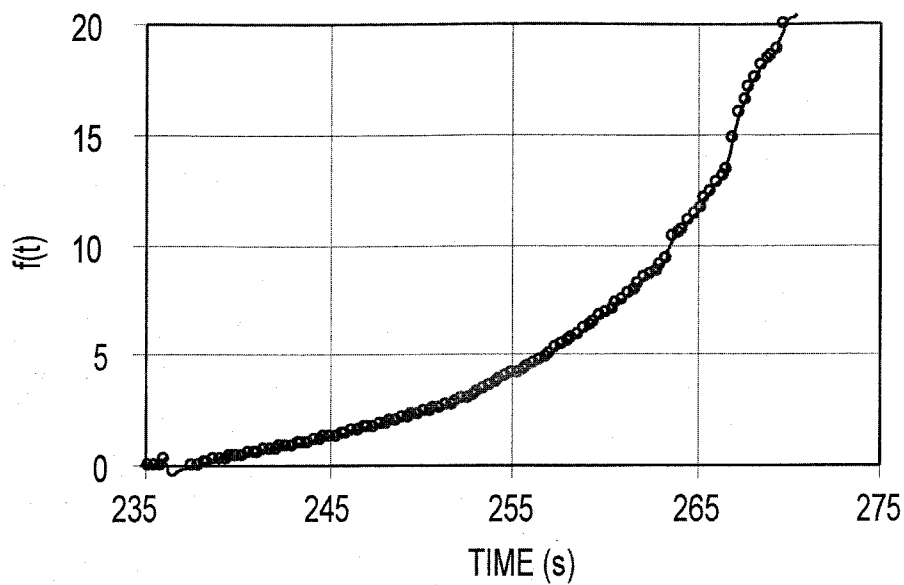
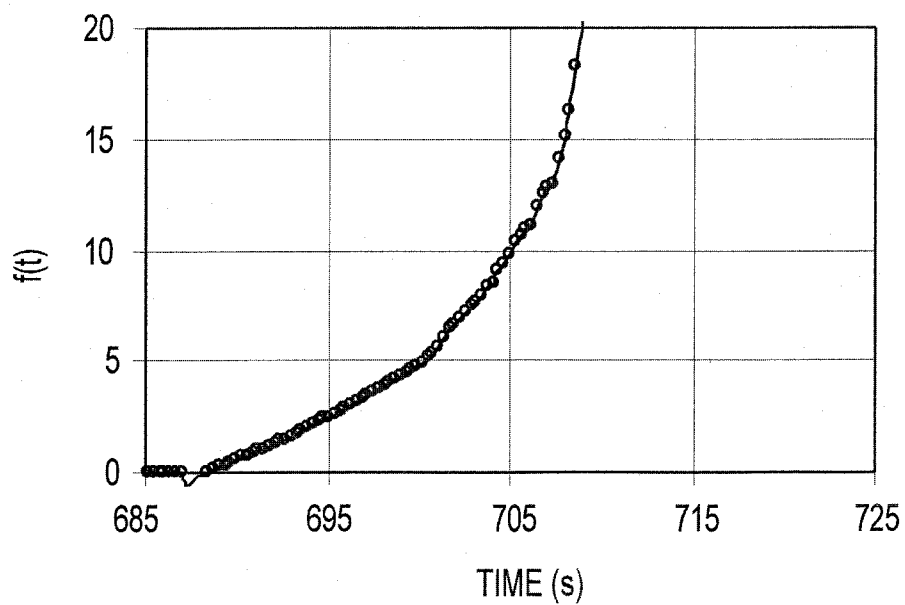
14/22

*Fig. 10A*

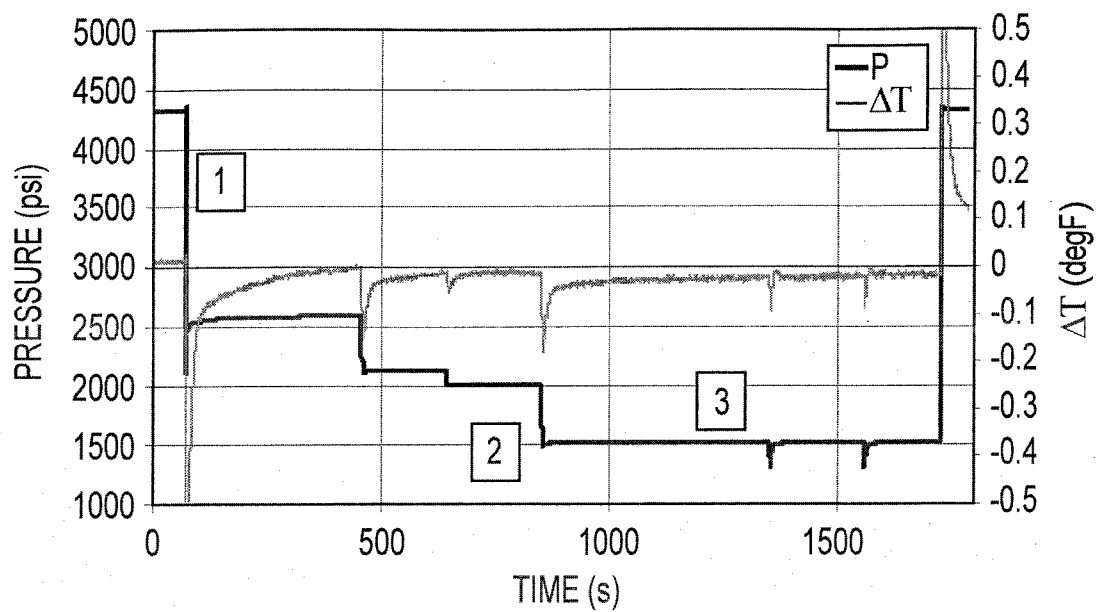
15/22

*Fig. 10B**Fig. 10C*

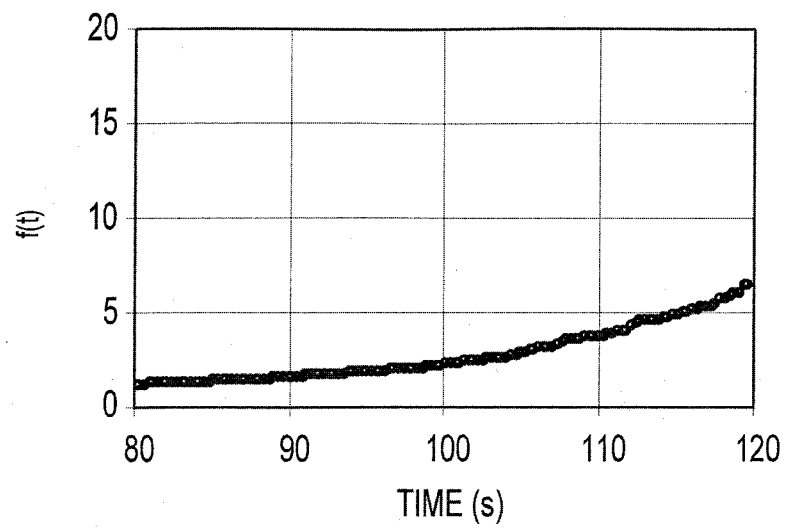
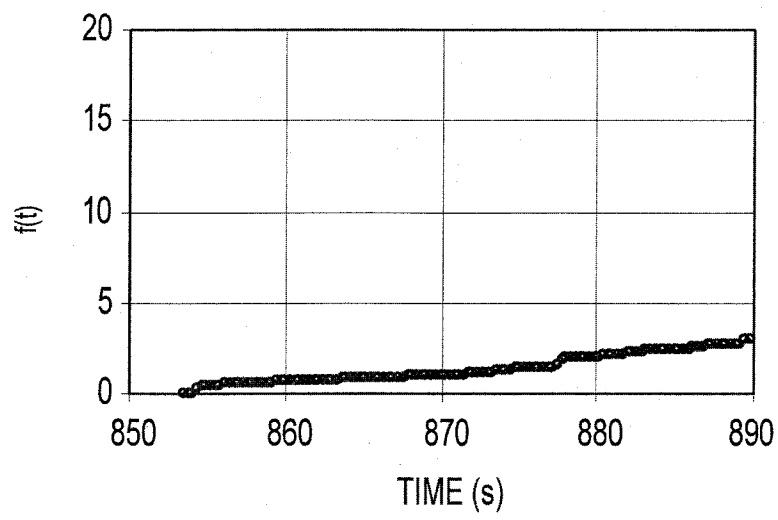
16/22

*Fig. 10D**Fig. 10E*

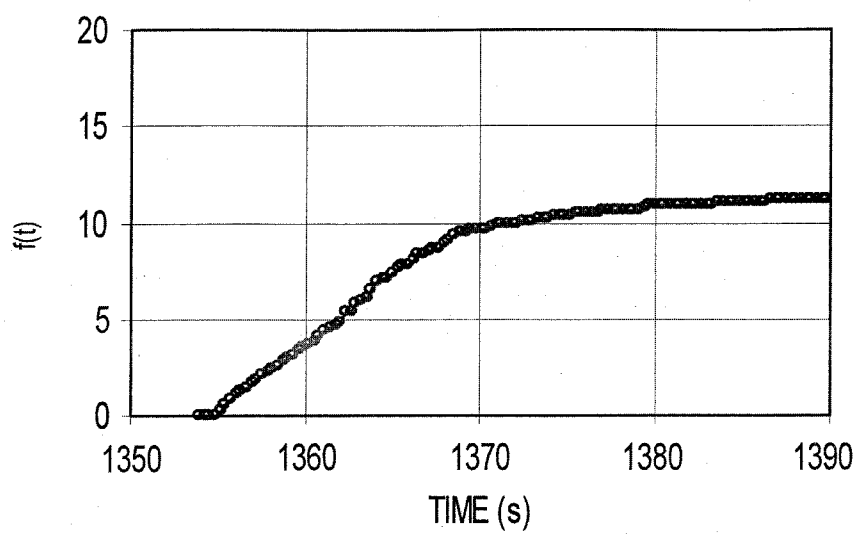
17/22

*Fig. 11A*

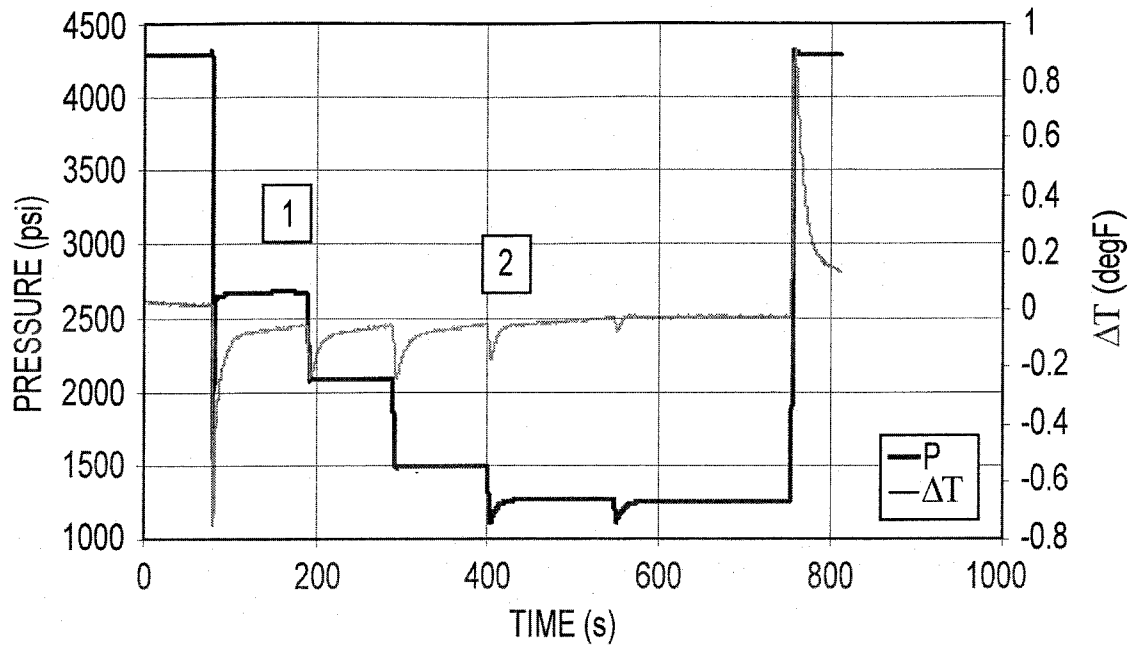
18/22

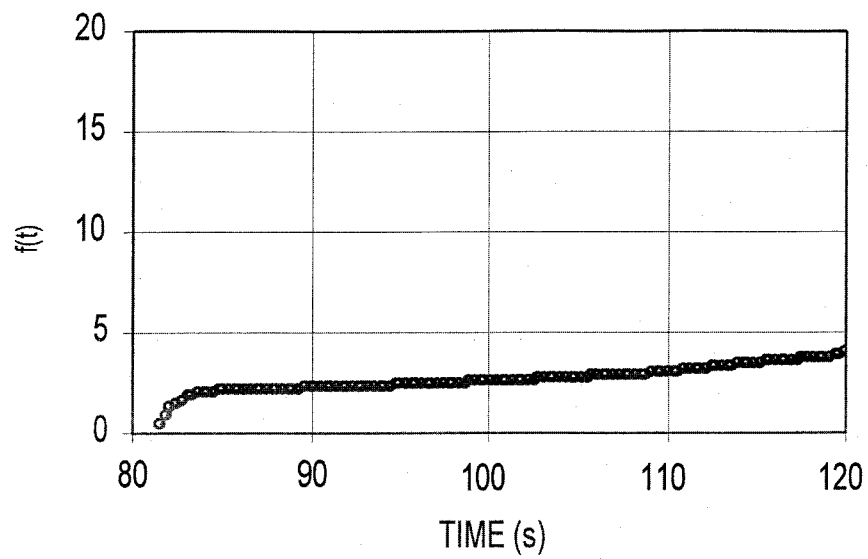
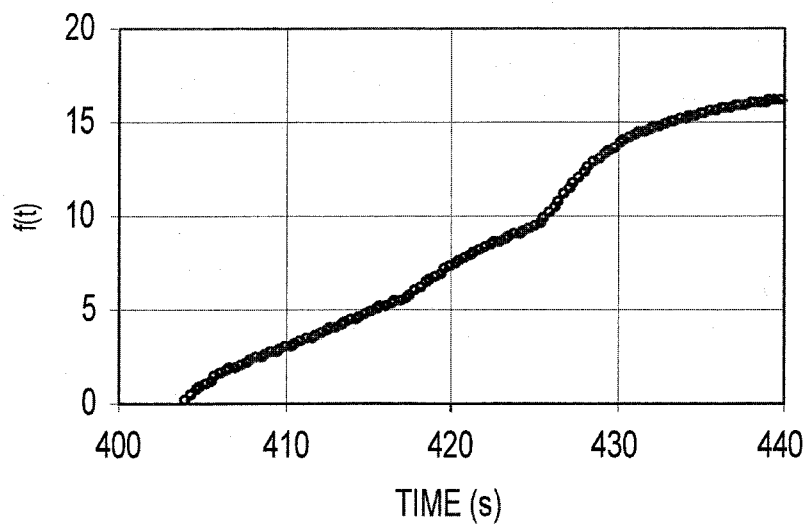
*Fig. 11B**Fig. 11C*

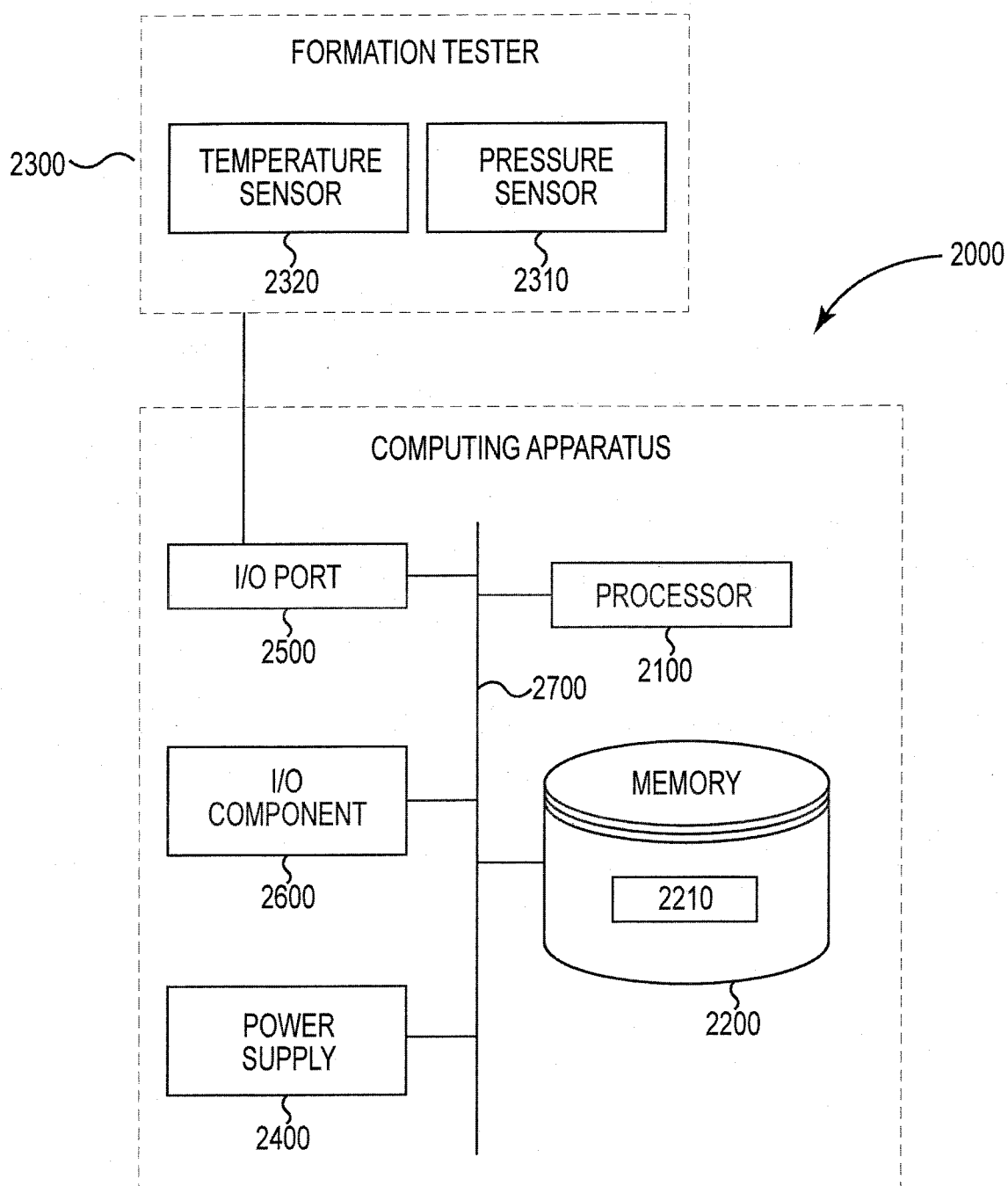
19/22

*Fig. 11D*

20/22

*Fig. 12A*

*Fig. 12B**Fig. 12C*

*Fig. 13*

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2012/07Q852

A. CLASSIFICATION OF SUBJECT MATTER
INV. E21B47/10 E21B47/06 E21B49/08
ADD.

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

EPO-Internal , WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 2006/191332 AI (MANIN YVES [FR] ET AL) 31 August 2006 (2006-08-31) page 4, paragraph 43 - page 5, paragraph 55 -----	1-11
A	US 2011/042071 AI (HSU KAI [US] ET AL) 24 February 2011 (2011-02-24) the whole document -----	1.7
A	US 2004/045706 AI (POP JULIAN [US] ET AL) 11 March 2004 (2004-03-11) page 2, paragraph 21 -----	1,7
A	US 2002/194907 AI (BOSTROM NEIL [US] ET AL) 26 December 2002 (2002-12-26) the whole document ----- - / - -	1.7



Further documents are listed in the continuation of Box C.



See patent family annex.

* Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier application or patent but published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search

19 February 2013

Date of mailing of the international search report

27/02/2013

Name and mailing address of the ISA/

European Patent Office, P.B. 5818 Patentlaan 2
NL - 2280 HV Rijswijk
Tel. (+31-70) 340-2040,
Fax: (+31-70) 340-3016

Authorized officer

Morris h, Susan

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2012/07Q852

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 5 741 962 A (BI RCHAK JAMES R [US] ET AL) 21 April 1998 (1998-04-21) the whole document -----	1, 7

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No

PCT/US2012/07Q852

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
US 2006191332	AI	31-08-2006	AT 426732 T 15-04-2009
		CA 2535054 AI	28-08-2006
		EP 1703076 AI	20-09-2006
		US 2006191332 AI	31-08-2006

US 2011042071	AI	24-02-2011	NONE

US 2004045706	AI	11-03-2004	CN 101092874 A 26-12-2007
		EP 1553260 A2	13-07-2005
		EP 1898046 A2	12-03-2008
		US 2004045706 AI	11-03-2004
		US 2004050588 AI	18-03-2004
		US 2005087009 AI	28-04-2005
		US 2005098312 AI	12-05-2005
		US 2005173113 AI	11-08-2005
		US 2005187715 AI	25-08-2005
		US 2007175273 AI	02-08-2007

US 2002194907	AI	26-12-2002	US 2002194907 AI 26-12-2002
			US 2004026076 AI 12-02-2004

US 5741962	A	21-04-1998	NONE
