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

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
14 April 2011 (14.04.2011)

PCT

(10) International Publication Number
WO 2011/042448 A2

(51) International Patent Classification:
E21B 49/08 (2006.01)

(21) International Application Number:
PCT/EP2010/064858

(22) International Filing Date:
5 October 2010 (05.10.2010)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
12/573,354 5 October 2009 (05.10.2009) US

(71) Applicant *(for all designated States except US)*: **BP EXPLORATION OPERATING COMPANY LIMITED** [GB/GB]; Chertsey Road, Sunbury-on-Thames Middlesex TW16 7BP (GB).

(72) Inventors; and

(75) Inventors/Applicants *(for US only)*: **YUSTI, German** [GB/US]; c/o BP America Inc., 4101 Winfield Road, Mail Code 5 East, Warrenville, Illinois 60555 (US). **REES, Hugh** [GB/US]; c/o BP America Inc., 4101 Winfield Road, Mail Code 5 East, Warrenville, Illinois 60555 (US). **WEBSTER, Michael** [GB/US]; c/o BP America Inc., 4101 Winfield Road, Mail Code 5 East, Warrenville, Illinois 60555 (US). **FOOT, John** [GB/US]; c/o BP America Inc., 4101 Winfield Road, Mail Code 5 East, Warrenville, Illinois 60555 (US).

(74) Agent: **HAMER, Christopher**; Mathys & Squire LLP, 120 Holborn, London Greater London EC1N 2SQ (GB).

(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, 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, PE, PG, PH, PL, PT, RO, RS, RU, 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, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, MD, 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).

Declarations under Rule 4.17:

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

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

Published:

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

WO 2011/042448 A2

(54) Title: MANAGING FLOW TESTING AND THE RESULTS THEREOF FOR HYDROCARBON WELLS

(57) Abstract: Automated monitoring and management of well tests of hydrocarbon wells in a production field. Routing of the output of a well to a flow meter, separated from the output from other wells in the field is detected by a computer system such as a server. Measurement data including the flow as measured by the flow meter, and also other measurements such as temperatures and pressures contemporaneous with the flow meter measurements, are acquired by the computer system; a stable period is identified, over which the flow test measurement data are considered valid. Upon completion of a specified duration or upon a change in the flow environment, the computer system notifies the user of the completion of the flow test. The flow test results can be used to modify predictive well models, with the modification dependent on validation by the user. The system can also plan and schedule future flow tests.

MANAGING FLOW TESTING AND THE RESULTS THEREOF FOR HYDROCARBON WELLS

* * * * *

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application is a continuation-in-part of co-pending application S.N. 12/035,209, filed February 21, 2008, which claims priority, under 35 U.S.C. § 119(e), of Provisional Application No. 60/891,617, filed February 26, 2007, incorporated herein by this reference.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

[0002] Not applicable.

BACKGROUND OF THE INVENTION

[0003] This invention is in the field of hydrocarbon (*i.e.*, oil and gas) production, and is more specifically directed to managing the operation and results of flow testing producing hydrocarbon wells and injecting wells over a production field.

[0004] Hydrocarbon production from subterranean reservoirs typically involves multiple wells positioned at various locations of a reservoir. In a given reservoir, the multiple wells are not only deployed at different surface locations, but are also often of different "geometry" from one another, and are also often drilled to different depths. Many typical wells also produce fluids at multiple depths along a single wellbore, thus producing from multiple subsurface strata. As is fundamental in the art, the fluid produced from a given well, as viewed at the wellhead, often includes multiple "phases", typically natural gas, petroleum or oil, and water. As used herein, the term "phase composition" or simply "phase" in reference to produced fluid refers to the relative amounts of water, oil and gases in the produced fluid. The produced fluid may also contain suspended solids such as sand or asphaltene compounds. In addition, as is well-known in the art, one or more wells into a reservoir may be configured for the injection of

fluids, typically gas or water, for secondary recovery and other reservoir management functions. Other injection liquids and gases are used and commercially available for use in secondary recovery and other reservoir management operations, as known in the art.

[0005] Knowledge of the rate of production and phase composition of the produced fluids are important properties for effective reservoir management and also for management of individual wells. Reservoir management typically includes the selection of the number of wells to be deployed in a production field, the locations and depths of these wells, the configuration of wells as production or injection wells, and decisions regarding whether to shut-in wells, or convert wells from production to injection wells or vice versa. Well management refers to decisions regarding individual wells, for example decisions regarding whether to perform remedial actions along the wellbore to improve production. Knowledge of production rate and phase information is, of course, also important from an economic standpoint.

[0006] Rate and phase information is commonly determined using flow meters or other equipment. For example, separating equipment may be located at or near a wellhead to separate produced phases so that the volume of each phase can be determined. Valves downstream from the separators divert all or a portion of the production stream for a separated phase to a flow meter or the like for measurement of the flow rate of that particular phase. Typically, this diversion is performed only periodically for each phase, for example once per month for a span of twelve hours, because of the effort and flow interruption involved in re-directing the flow of the various phases and because the metering device or separator is required for other production-related purposes. This lack of real-time flow measurements of course reduces confidence in the measurements obtained, and in the decisions made based on those measurements.

[0007] In addition to the cumbersome nature of these flow measurements, conventional flow meters generally require frequent calibration to ensure accuracy, considering the typical drift of conventional flow meters over time. Conventional flow meters are also typically calibrated to be accurate only within a certain operating range. If operating conditions change so that the steady-state condition of a well drifts outside

the operating range, the flow measurements can be unreliable. In either case, calibration drift or change in operating conditions, the flow meter must be recalibrated, adjusted, or replaced, each action usually requiring physical intervention.

[0008] While recalibration and maintenance of flow meters is somewhat cumbersome for land-based wells, the recalibration and maintenance of flow meters is typically prohibitively difficult and costly in marine environments. In addition, the inability to service offshore flow meters can cause total loss of flow measurement if a critical sensor fails. Deep sea marine environments present particularly significant challenges for maintenance or otherwise routine operations. For example, flow meters located within a well or at a wellhead can be prohibitively difficult to recalibrate due to the difficult access for maintenance, as costly intervention vessels and other equipment are often required.

[0009] In addition, not all wells in a production field are typically equipped with a dedicated flow meter. Rather, many wells share access to flow meters with other wells in the field. This is especially true in off-shore production, because of the difficulty of maintaining sea-bed downhole sensors in the deep-sea environment. This sharing has been observed to add uncertainty in rate and phase measurements. Typically, in such a shared metering environment, especially offshore, production from several wells is commingled before reaching any platform or other topside facility. As used herein, "topside" in reference to equipment or facilities means equipment or facilities which are located either at or above ground for land-based wells, or at or above the water surface for sea environments (*e.g.*, production platforms and shore-bound surface facilities). In either case, shared topside flow metering typically does not allow determination of production from individual wells without stopping production from other wells.

[0010] By way of further background, U.S. Patent Application Publication No. 2004/0084180 describes a method of estimating multi-phase flow rates at each of multiple production string entries located at varying depths along a wellbore, and thus from different production zones of a single well. According to the method of this publication, a volumetric flow rate for each phase is obtained at the wellhead, which of

course includes production from each of the downhole production zones. The measured volumetric wellhead flow, along with downhole pressure and temperature measurements, are applied to a well model to iteratively solve for estimates of the flow rate of each phase at each downhole production string entry location.

[0011] By way of further background, software packages for modeling the hydraulics of hydrocarbon wells, as useful in the design and optimization of well performance, are known in the art. These conventional modeling packages include the PROSPER modeling program available from Petroleum Experts Ltd, the PIPESIM modeling program available from Schlumberger, and the WELLFLOW modeling program available from Halliburton. These software modeling packages utilize actual measured, or estimated, values of flow, pressure, and temperature parameters to characterize the modeled well and to estimate its overall performance. In addition, these modeling packages can assist in decision making, for example by evaluating the effect on well performance of proposed changes in its operation.

[0012] By way of still further background, U.S. Patent Application Publication No. US 2005/0149307 A1, published July 7, 2005, describes the use of well models in reservoir management. Pressure measurements, multi-phase flow rates, etc. are applied to a well production model, and the model is verified based on various well and reservoir measurements and parameters.

[0013] The conventional uses of well modeling in well and reservoir management, especially involving the determination of rate and phase values, operate as "snapshots" in time. In other words, the various measurements acquired in the field are applied to the well model "off-line", with the well model operated by a human engineer or other operator to determine an estimate of the state of the well. Examples of users and operators who operate and analyze the well model in this fashion include, among others, petroleum engineers, reservoir engineers, geologists, operators, technicians, and the like. In many instances, the measurements are obtained or inferred from well tests, such as shut-in tests, during which the well is shut-in suddenly, and the subsequent response of the measured pressure is recorded. Such scheduled well testing is, of course, infrequent

in a producing field. And as is well-known in the art, substantial human effort and judgment is often required to select an appropriate well model for a particular set of measurements, to apply judgment and filtering to measurements that appear to be inaccurate, and to evaluate the well model results.

[0014] By way of further background, the deployment of downhole pressure and temperature sensors has become increasingly common in recent years, because of improvement in the reliability and long-term performance of such downhole sensors. These modern downhole sensors can now provide measurement data on a continuous and near real time basis, with measurement frequencies exceeding one-per-second.

[0015] As is fundamental in the art, modern producing fields include a large number of producing wells. Typically, the split of revenue among royalty participants is uniformly allocated based on the overall output of the field, rather than necessarily allocated based on the output from individual wells in the field, considering that the metering of output from individual wells would be a costly undertaking. As such, the flow from all wells in the field is typically combined and measured as a whole, for example as an overall daily volume from the field. This measurement of the combined output over the field is sufficient for economic purposes, even though the output of individual wells in the field varies to a wide extent.

[0016] On the other hand, from the standpoint of well and reservoir management, reservoir engineers or other operators or users are interested in the output of individual wells, both relative to one another within the field and also as such output varies over time and conditions. Knowledge of the output of individual wells enables the timely maintenance of individual wells, should the output drop over time. This knowledge also facilitates management of the reservoir, and optimization of production from the field as a whole. In this regard, optimization of the production response of the field, as a whole, to stimulation, injection, pressure support, and secondary recovery processes, can be attained from knowledge of individual well output over time. And, of course, knowledge of the output of individual wells in the field will greatly assist the placement of new wells.

[0017] In conventional production fields, therefore, some capability for measuring the fluid output from individual wells, at least on a periodic or sampled basis, is generally provided. Such periodic or sampled flow measurement of an individual well is referred to in the art as a "flow test". In a typical flow test, the output stream from a given well is physically isolated from the output of other wells in the field, and directed to a flow meter for measurement over several hours. The flow meter may measure only a separated single phase (*i.e.*, oil, gas, or water) from a selected well, or alternatively may be a "multi-phase" flow meter that simultaneously measures the output of all phases produced from the well. In modern well and reservoir management approaches, the well output is correlated to contemporaneous measurements of reservoir pressure and well flowing pressure at the well under analysis; other parameters such as downhole temperature, surface conditions, in-well flowing pressure, and the like may also be contemporaneously measured and correlated to the meter flow. These measurements thus "calibrate" the pressure and temperature measurements that can be obtained during normal production so that insight into the particular well's flow can be deduced from pressure and temperature measurements. In addition, well and reservoir models can be calibrated by the periodic or sampled flow measurement from individual wells. From an economic viewpoint, these models and parameters, as calibrated by the well flow measurements, can be used to derive an "allocation" of the overall field production to individual wells in the field.

[0018] Conventional approaches to flow tests of wells in a production field are generally *ad hoc*, in that the scheduling and performing of such tests are typically at the discretion and judgment of the reservoir engineers, or other members of the production operations staff. In addition, some level of human judgment is often involved in analysis of the vast amount of data acquired from flow tests over an entire production field. Such judgment is even involved in the determination of which data from a flow test ought to be considered, because some level of instability in the flow conditions is often present in the wells under test, and thus the selection of a "steady-state" measurement period is somewhat subjective. Inconsistency in the treatment of flow test data among different personnel and field locations can preclude accurate comparison of well and field

performance over time, or among multiple fields. In addition, the vast amount of data makes conventional processing of flow test results a cumbersome task.

BRIEF SUMMARY OF THE INVENTION

[0019] It is therefore an object of this invention to provide automated detection, analysis, and validation of flow tests and results of these tests for oil and gas production fields.

[0020] It is a further object of this invention to coordinate flow test results with real-time rate and phase monitoring of hydrocarbon wells.

[0021] It is a further object of this invention to provide automated and intelligent planning and scheduling of flow tests for the wells in a production field.

[0022] It is a further object of this invention to provide update predictive well models with actual flow test results, to improve the accuracy of such models.

[0023] It is a further object of this invention to provide an automated system and method for evaluating the stability of real-time flow test results to ensure the validity of data to be evaluated, and to control the duration of flow tests.

[0024] It is a further object of this invention to provide uniformity and consistency in the analysis of flow test data.

[0025] It is a further object of this invention to improve allocation calculations for oil and gas production fields.

[0026] Other objects and advantages of this invention will be apparent to those of ordinary skill in the art having reference to the following specification together with its drawings.

[0027] Embodiments of this invention provide a method, computer system, or computer-readable medium storing a computer program for planning, monitoring, and analyzing flow tests for one or more wells within a production field.

[0028] In an embodiment of this invention, such a method, computer system, or computer-readable medium provides automated detection and processing of a flow test being carried out, without requiring user intervention or interaction before completion of the flow test.

[0029] In an embodiment of this invention, such a method, computer system, or computer-readable medium provides automated determination of the time at which valid flow test data are obtained, and automated determination of the end of the flow test.

[0030] In an embodiment of this invention, such a method, computer system, or computer-readable medium provides automated calibration and adjustment of predictive well models based on recent flow test measurements.

[0031] In an embodiment of this invention, such a method, computer system, or computer-readable medium storing a computer program provides automated planning and scheduling of future flow tests in a production field.

[0032] In an embodiment of this invention, a method, computer system, or computer-readable medium storing a computer program provides automated communication of flow test results to human users for validation of flow test results.

[0033] Embodiments of this invention may be implemented in a method, computer system, or computer-readable medium storing an executable computer program, that automates the gathering, processing, and planning of flow tests of wells in a production field. In one example of a server-client architecture, servers in a network include software modules. One software module detects the routing of well output piping to a flow meter, and monitors the measurement data obtained from that flow meter for stability of measurement data over a test interval. Upon detection that sufficient flow test data have been processed or upon another event, the results of the test are forwarded to one or more human users.

[0034] According to other embodiments of this invention, the results of completed flow tests are used to calibrate or adjust existing predictive well models. As a result, the predictive flow test models are better able to estimate flow rate and phase for producing wells at times other than during flow tests, and to better estimate other well and reservoir parameters.

[0035] According to other embodiments of this invention, the results of flow tests are processed to derive a schedule for future flow tests, based on the results obtained in previous flow tests and based on other parameters.

BRIEF DESCRIPTION OF THE SEVERAL VIEWS OF THE DRAWING

[0036] Figure 1 is a schematic diagram illustrating the measurement and analysis system of an embodiment of the invention as deployed in an oil and gas production field.

[0037] Figure 2 is a schematic diagram illustrating an example of a well with its associated sensors and transducers as implemented in the system of that embodiment of the invention.

[0038] Figure 3 is a graphical representation of the output of a well model according to that embodiment of the invention.

[0039] Figure 4 is an electrical diagram, in block and schematic form, of a computer system such as a server implementing the analysis system of that embodiment of the invention.

[0040] Figure 5 is a block diagram illustrating the software architecture implemented in the system computing resources of Figure 4, implementing the analysis system of that embodiment of the invention.

[0041] Figure 6 is a block diagram illustrating the software architecture implemented in the system computing resources of Figure 4, implementing the analysis system of an embodiment of the invention in a multi-asset application.

[0042] Figure 7 is a schematic diagram illustrating information processing steps in an embodiment of this invention.

[0043] Figure 8 is a flow diagram illustrating the operation of an automated analysis method according to an embodiment of the invention.

[0044] Figure 9 is a flow diagram illustrating, in further detail, the operation of evaluating a well model in the method of Figure 5, according to that embodiment of the invention.

[0045] Figures 10a and 10b are graphic representations, illustrative of output from a calibrated predictive model showing downhole fluid pressure as a function of fluid

rate for a range of constant gas-oil ratio values, and fluid temperature at the wellhead as a function of fluid rate for a range of gas-oil ratio values, respectively.

[0046] Figure 11 is a flow diagram illustrating the operation of one possible selection procedure based on arranging a hierarchy of multiple well models evaluated according to the method of Figure 8, according to that embodiment of the invention.

[0047] Figure 12 is a state diagram illustrating the operation of an example of the determination of well operating state in the process of Figure 8, according to that embodiment of the invention.

[0048] Figure 13 is a schematic diagram illustrating an example of an oil and gas production field to which embodiments of the invention are applied.

[0049] Figure 14 is a schematic diagram illustrating the implementation of a flow meter for periodic or sampled flow tests of one of multiple wells.

[0050] Figure 15 is a flow diagram illustrating the operation of performing and analyzing flow tests of a well according to an embodiment of the invention.

[0051] Figure 16 is an illustration of a browser window presenting results of the operation of a flow test according to the embodiment of the invention of Figure 15.

DETAILED DESCRIPTION OF THE INVENTION

[0052] The present invention will be described in connection with its embodiments, namely as implemented into an existing production field from which oil and gas are being extracted from one or more reservoirs in the earth, because it is contemplated that this invention will be especially beneficial when used in such an environment. However, it is contemplated that this invention may also provide important benefits when applied to other tasks and applications. Accordingly, it is to be understood that the following description is provided by way of example only, and is not intended to limit the true scope of this invention as claimed.

[0053] As will be evident to those skilled in the art having reference to this specification, embodiments of this invention employ physical models, temperature sensors and pressure sensors, and where applicable, valves and choke positions, to determine the rate and phase of fluid produced from a well. This invention can also provide rate and phase data and information, and other useful information, on a continuous basis in real-time or near-real-time, to allow improved well or field operation. As used herein, the "real time" or "near real time" operation refers to the ability of this invention to provide such rate and phase data and information, and other such useful information, sufficiently timely so that the results, when provided, reflect a reasonably current state of the well. For example, it is contemplated that, according to embodiments of this invention, the rate and phase data and information is provided at least as frequently as every few hours, preferably ranging from about once every hour or two to as frequently as several times each hour, as frequently as about every five minutes, or even as frequently as once per minute. As used herein, the "continuous" operation of providing rate and phase data and information refers to the operation of embodiments of this invention so that, following the completion of one instance of the determination of rate and phase information for a given well or wells, a next instance of that process starts, without any significant or substantial delay. For example, it is contemplated that "continuous" refers to the operation of embodiments of this invention on a periodic basis, with one period effectively beginning upon the end of a previous period, such periods of

lengths as mentioned above, ranging from as frequently as about once per minute (or more frequent yet) to on the order of about once every few hours.

[0054] Figure 1 illustrates an example of the implementation of an embodiment of the invention as realized in an offshore oil and gas production field. In this example, two offshore drilling and production platforms 2_1, 2_2 are shown as deployed; of course, typically more than two such platforms 2 may be used in a modern offshore production field. Each of platforms 2_1, 2_2 supports one or more wells W, shown by completion strings 4_{11} through 4_{14} supported by platform 2_1, and completion strings 4_{21} through 4_{24} supported by platform 2_2. Of course, more or fewer than four completion strings 4 may be supported by a single platform 2, as known in the art. A given completion string 4 and its associated equipment, including downhole pressure transducers PT, wellhead pressure transducers WPT, wellhead temperature transducers WTT, flow transducers FT, and the like, will be referred to in this description as a well W, an example of which is well W_{12} indicated in Figure 1.

[0055] According to this embodiment of the invention, one or more downhole pressure transducers or sensors PT is deployed within each completion string 4. Downhole pressure transducers PT are contemplated to be of conventional design and construction, and suitable for downhole installation and use during production. Examples of modern downhole pressure transducers PT suitable for use in connection with this invention include those available from Quartzdyne Inc., among others available in the industry.

[0056] In addition, as shown in Figure 1, conventional wellhead pressure transducers WPT are also deployed at the wellheads at platforms 2. Wellhead pressure transducers WPT are conventional wellhead pressure transducers as well known in the art, and sense pressure at the wellhead, typically at the output of multiple wells after the flows are combined; alternatively, wellhead pressure transducers WPT can be dedicated to individual wells W. Figure 1 also illustrates wellhead temperature transducers WTT, which sense the temperature of the fluid output from the wells W served by a given

platform 2, also at the wellhead; again, wellhead temperature transducers WTT may serve individual wells W at platform 2, if so deployed.

[0057] It is contemplated that other downhole and wellhead sensors may also be deployed for individual wells, or at platforms or other locations in the production field, as desired for use in connection with this embodiment of the invention. For example, downhole temperature sensors may also be implemented if desired. In addition, not all wells W may have all of the sensor and telemetry of other wells W in a production field, or even at the same platform 2. Furthermore, injecting wells W will typically not utilize downhole pressure transducers PT, as known in the art.

[0058] Figure 2 schematically illustrates an example of the deployment of various pressure, temperature, and position transducers along one of completion strings 4 in well W_1 in the production field illustrated in Figure 1. Figure 2 illustrates a portion of completion string 4 as disposed in a wellbore that passes into a hydrocarbon-bearing formation F. In this simplified schematic illustration, completion string 4 includes one or more concentric strings of production tubing disposed within wellbore 3, defining an annular space between the outside surface of the outermost production tubing and the wall of wellbore 3. Entries through the production tubing pass fluids from one or more formations F into the interior of the production tubing, and within any annulus between concentrically placed production tubing strings, in the conventional manner. The annular space between wellbore 3 and completion string 4 (and also any annuli between inner and outer production tubing strings) may be cemented to some depth, as desired for the well. Packers (not shown) may also be inserted into the annular space between wellbore 3 and completion string 4 to control the pressure and flow of the production stream, as known in the art. Completion string 4 terminates at the surface, at wellhead 9.

[0059] According to an embodiment of the invention, and as known in the art, downhole pressure transducer PT is preferably disposed in completion string 4 at a depth that is above the influx from shallowest hydrocarbon-bearing formation F. As will become apparent from the following description, the shut-in condition of the well is of particular usefulness in the analysis method of this embodiment of the invention.

Downhole pressure transducer PT is in communication with data acquisition system 6 (Figure 1) by way of a wireline or other communications facility (not shown in Figure 2) in completion string 4.

[0060] As mentioned above, additional sensors may also be deployed in connection with completion string 4, for purposes of an embodiment of the invention, for example as shown in Figure 2. Wellhead pressure and temperature transducers WPT, WTT, respectively, are deployed within production string 4 at or near wellhead 9, for sensing pressure and temperature for well W at the wellhead. In addition, well annulus pressure transducer APT is deployed within the annulus between wellbore 3 and the outermost production tubing of completion string 4, at or near wellhead 9, for sensing the annular pressure near the surface. Other sensors and transducers specific to well W can also be deployed at wellhead 9. As shown in Figure 2, these additional sensors include choke valve position indicator CPT, which of course indicates the position of choke 7, and thus the extent to which choke 7 is opening or closing the fluid path from completion string 4 to the production flowline. Well W, in the example of Figure 2, also includes gaslift capability, as conventional in the art, and in connection with which various sensors are provided. On the gas lift supply side, gas lift pressure transducer GLPT and gas lift flow transducer GLFT measure the pressure and flow, respectively, of the gas being supplied to well W for gaslift operation. Gaslift control valve position transducer GLVPT indicates the position of the gaslift control valve. Each of these transducers illustrated in Figure 2 for well W, and any other transducers utilized either downhole, at wellhead 9, or downstream from wellhead 9 in the production flowline, are coupled to data acquisition system 6 for the platform 2 or other arrangement of wells, so that the measurements can be acquired and forwarded to servers 8 according to this embodiment of the invention, as will be described below and as illustrated in Figure 1.

[0061] As illustrated in Figure 1, volumetric flow transducers FT can also optionally be deployed in line with each of completion strings 4, for each of the wells supported by each of platforms 2, or plumbed into the production flowline in a shared manner among multiple wells. Such flow transducers FT are of conventional design and construction, for measuring the flow of fluid (including all phases of gas, oil, and water).

As will be described in further detail below, the flow from a given well or completion string, for each phase (oil, gas, water) can be determined from pressure transducers PT in combination with measurements of downhole temperature, according to this embodiment of the invention.

[0062] Referring back to Figure 1 for this example of this embodiment of the invention, and as mentioned above, platforms 2_1, 2_2 are each equipped with a corresponding data acquisition system 6_1, 6_2. Data acquisition systems 6 are conventional computing and processing systems deployed at the production location, and which manage the acquisition of measurements from the sensors and transducers at platforms 2 and in connection with the completion strings 4 at that platform 2. Data acquisition systems 6 also manage the communication of those measurements to shore-bound servers 8, in this embodiment of the invention, such communications being carried out over a conventional wireless or wired communications link LK. In addition, data acquisition systems 6 are each capable of receiving control signals from servers 8, for management of the acquisition of additional measurements, calibration of its sensors, and the like. Data acquisition systems 6 may apply rudimentary signal processing to the measured signals, such processing including data formatting, time stamps, and perhaps basic filtering of the measurements, although it is contemplated that the bulk of the filtering and outlier detection and determination will typically be carried out at servers 8.

[0063] Servers 8, in this example, refer to multiple servers located centrally or in a distributed fashion, and operating as a shore-bound computing system that receives communications from multiple platforms 2 in the production field, and that operates to carry out the analysis of the downhole pressure measurements according to this embodiment of the invention, as will be described in further detail below. Servers 8 can be implemented according to conventional server or computing architectures, as suitable for the particular implementation. In this regard, servers 8 can be deployed at a large data center, or alternatively as part of a distributed architecture closer to the production field. Also according to this embodiment of the invention, one or more remote access terminals RA are in communication with servers 8 via a conventional local area or wide area network, providing production engineers, or other operators or users, with access to the

measurements acquired by pressure transducers PT and communicated to and stored at servers 8. Examples of users and operators who are contemplated to access these measurements via remote access terminals RA, or who otherwise operate and use embodiments of this invention, include, among others, petroleum engineers, reservoir engineers, geologists, operators, technicians, and the like. In addition, as will become apparent from the following description, it is contemplated that servers 8 will be capable of notifying production engineers or other such users and operators of certain events detected at one or more of pressure transducers PT, and of the acquisition of measurement data surrounding such events. This communication, according to this invention, provides the important benefit that the responsible personnel are not deluged with massive amounts of data, but rather can concentrate on the measurements at completion strings 4 for individual wells that are gathered at important events, from the standpoint of well and production field characterization and analysis. In an embodiment of the invention, a process trigger causes a notification which is transmitted to a desired location or user. In an embodiment, the notification is visual or auditory. In other embodiments of the invention, the notification is vibrational, such as a signal sent to a pager, mobile phone, or other electronic device, or is carried out by a phone call, an email, a text message, or an automated message, any of which is transmitted to the appropriate user. In an example of such an embodiment, an email may be automatically sent to the responsible user along with a network link to the event which triggered the notification. In embodiments of this invention, the particular triggering events are pre-determined in the system, or are configured in the system by the appropriate user.

[0064] While the implementation of this embodiment of the invention illustrated in Figure 1 is described relative to an offshore production field environment, those skilled in the art having reference to this specification will readily recognize that this invention is also applicable to the management of terrestrial hydrocarbon production fields, and of individual wells and groups of wells in such land-based production. Of course, in such land-based oil and gas production, the wells and their completion strings are not platform-based. As such, each well or completion string may have its own data acquisition system 6 for communication of its transducer measurements to servers 8;

alternatively, a data acquisition system may be deployed near multiple wells in the field, and as such can manage the communication of measurements from those multiple wells in similar fashion as the platform-based data acquisition systems 6 of Figure 1.

[0065] According to embodiments of this invention, as will become apparent from the following description, servers 8 operate to derive estimates of flow rate for each of multiple phases of produced fluid (gas, oil, water) from the pressure, temperature, and position measurements acquired as in the example of Figure 2. In addition, according to embodiments of this invention, servers 8 may also operate to deduce an operating state or mode of well W from these measurements, as will be described in further detail. These derivations of rate, phase, and operating mode are obtained by servers 8 by the application of the measurements to one or more computer-operated predictive well models, preferably with the results selected from these derivations by an automated procedure taking account of the measurements themselves.

[0066] According to embodiments of this invention, the well models used by servers 8 to derive rate, phase, and operating mode are based on conventional hydraulic well models as known in the art. These conventional and known hydraulic well models include such models as the PROSPER modeling program available from Petroleum Experts Ltd, the PIPESIM modeling program available from Schlumberger, and the WELLFLOW modeling program available from Halliburton. These models generally operate as a hydraulic model of the well pipe as a primary model, based on physical and thermodynamic laws governing fluid flow. Another model that is useful in connection with the embodiments of this invention is the well-known Perkins choke differential pressure model, as described in Perkins, "Critical and Subcritical Flow of Multiphase Mixtures Through Chokes", SPA Paper No. 20633 (Society of Petroleum Engineers, 1993), incorporated herein by this reference. Other modeling techniques can also be used in place of these conventional hydraulic well models, or included along with those hydraulic well models to add robustness to the overall system. It is also contemplated that other new or modified hydraulic well models can be readily applied to the monitoring system implemented according to embodiments of this invention, without undue experimentation by those skilled in the art having reference to this specification.

[0067] In a simplified sense, the well models used in connection with embodiments of this invention treat the modeled well analogously to a pipeline incorporating the physical geometry of the well. In some cases, the well model is a one dimensional model calculating fluid properties as a function of length of the well. Other well models can incorporate more than one dimension along all or a portion of the well. For example, fluid flow can be modeled as a function of length and radial distance. As further example, fluid flow can be modeled in three dimensions. In some cases, fluid flow is modeled in one dimension for most of a well and in more than one dimension for a specific portion of the well. For example, in particular areas of the well where flow deviates greatly from one-dimensional consideration, one or more other dimension may be included in that area. By using such simplified models, rate and phase values can be calculated several times each minute.

[0068] According to embodiments of this invention, a number of hydraulic models are available for use in deriving measurements of rate and phase. These hydraulic models calculate rate and phase, and in some cases reservoir pressure or other parameters, by matching calculations of downhole pressure or wellhead temperature (or both) by the well model to the actual measurements of those parameters. One class of these hydraulic models is based on models of both inflow and the production tubing that makes up completion string 4. These models are most useful in situations in which the reservoir pressure is known to a high level of confidence. According to these models, referred to herein as "full" or "inflow-and-tubing" models, the calculation of the phase parameter is optimized to match the measured downhole pressure, or to match the measured wellhead temperature.

[0069] Figure 3 illustrates an example of rate and phase calculations using a simplified "inflow-and-tubing" model according to an embodiment of the invention. Curve 31 illustrates the relationship of a phase parameter (*e.g.*, watercut) to a measured parameter such as downhole pressure, in this example, according to the selected tubing and inflow model for a given well W. Curve 33 illustrates the relationship between the phase parameter (*e.g.*, watercut) to an inferred production rate, also according to the same full model. Upon obtaining the measured parameter of downhole pressure, in this

example, that measured downhole pressure is applied to the well model for well W from which the measurement was taken, to derive the phase parameter of watercut from curve 31. Once that phase parameter value is deduced from the well model, that phase parameter value is applied to the well model to produce the resulting production rate, via curve 33 of Figure 3. In this manner, the selected well model for well W is used to produce rate and phase information from a downhole pressure measurement.

[0070] As mentioned above, this class of inflow-and-tubing well model can also operate based on a measurement of wellhead temperature, instead of the measured downhole pressure as discussed above.

[0071] Another type of well model used in connection with embodiments of this invention is based only on the hydraulics model of the tubing, and does not model the inflow into the tubing. Because inflow is not modeled by this class of "tubing-only" models, reservoir pressure need not be known or assumed; rather, this class of model is able to infer reservoir pressure from the other measurements. In a general sense, this type of model operates by adjusting the phase parameter and the production rate (*i.e.*, curves 31, 33 of Figure 3) to simultaneously match the measured downhole pressure and the measured wellhead temperature.

[0072] Of course, actual generation of the rate and phase parameter values using a well model according to embodiments of this invention is not carried out graphically through the use of curves and plots, as suggested by Figure 3. Rather, as will be described in further detail below, automated programmed numerical and analytical techniques are used to calculate the desired results.

[0073] The following Table 1 is an example of the measurements and well models used in an embodiment of the invention, for purposes of understanding the context of the present invention. In this example, the models applied include the "Perkins Choke" model, and the hydraulics well models in different operating modes or options, depending on the available measurement data as will be illustrated. The hydraulic well models may correspond to the PROSPER models noted above, or additionally or alternatively to other hydraulic well models, including such other similar hydraulic well

models known in the art or which may later be developed. It is contemplated that the scope of this invention as hereinafter claimed is not limited to the particular models that may be used; as such, these particular models are presented by way of example only. In addition, as evident from Table 1, the example of a PROSPER choke model is also available and may also be applied in combination with the other models. As known in the art, a "choke" model infers rate and phase based on a measured differential pressure drop across the production choke valve, and using an estimate of gas-oil ratio or watercut. The hydraulics models, as described above, derive the rate and phase estimates that match the measurements of downhole pressure or wellhead temperature, for example. Further in addition to these enumerated models, user-defined numerical equations can also be incorporated into the rate and phase determination, depending on the available measurement data and also upon the equations so defined by the user.

Table 1

		Parameter values (RQ=required measurement, AS=assumed value, CALC=calculated value)						
Model name/options		Wellhead pressure	Wellhead temperature	Downhole pressure	Reservoir pressure	Watercut (WGR)	Gas-oil ratio (GOR) or condensate-gas ratio (CGR)	Gaslift injection rate
Perkins choke model		RQ	CALC	n/a	n/a	AS	AS	RQ
Full model (no phase matching)	Hydraulic inflow-and-tubing models	RQ	CALC	CALC	AS	AS	AS	RQ
Full model matched to DHP (DHP)		CALC	CALC	RQ	AS	AS	AS	RQ
Full model (DHP) with adjusted WGR		RQ	CALC	RQ	AS	CALC	AS	RQ
Full model matched to WHT with adjusted WGR		RQ	RQ	CALC	AS	CALC	AS	RQ
Full model (DHP) with adjusted GOR/CGR		RQ	CALC	RQ	AS	AS	CALC	RQ
Full model (WHT) with adjusted GOR/CGR		RQ	RQ	CALC	AS	AS	CALC	RQ
Full model (DHP) with adjusted gaslift value		RQ	CALC	RQ	AS	AS	AS	CALC
Full model (WHT) with adjusted gaslift		RQ	RQ	CALC	AS	AS	AS	CALC

Model name/options		Parameter values (RQ=required measurement, AS=assumed value, CALC=calculated value)						
		Wellhead pressure	Wellhead temperature	Downhole pressure	Reservoir pressure	Watercut (WGR)	Gas-oil ratio (GOR) or condensate-gas ratio (CGR)	Gaslift injection rate
Tubing model (DHP)	Tubing-only model (no inflow modeling)	RQ	CALC	RQ	CALC	AS	AS	RQ
Tubing model (WHT)		RQ	RQ	CALC	CALC	AS	AS	RQ
Tubing model (DHP and WHT), adjust WGR		RQ	RQ	RQ	CALC	CALC	AS	RQ
Tubing model (DHP and WHT), adjust GOR		RQ	RQ	RQ	CALC	AS	CALC	RQ
Tubing model (DHP and WHT), adjust gaslift		RQ	RQ	RQ	CALC	AS	AS	CALC
PROSPER choke model		RQ	RQ	n/a	n/a	AS	AS	RQ
User-defined empirical rate estimates		User-defined	User-defined	User-defined	User-defined	User-defined	User-defined	User-defined
Well-specific rate measurements		n/a	n/a	n/a	n/a	n/a	n/a	n/a

In Table 1, the phase matching approach of "DHP" refers to matching the calculated rates and phase relative to downhole pressure, while the phase matching of "WHT" refers to matching the calculated rates and phase relative to wellhead temperature. As evident from Table 1, the tubing-only models match rates and phases to both downhole pressure and wellhead temperature, given the additional degree of freedom resulting from no inflow modeling. In addition, as shown in Table 1, user-defined empirical rate estimates can be included in the set of well models 27; for this user-defined case, the particular parameters used in order to derive rate and phase are defined by a human user on a case-

by-case basis, and as such may not rely on any specific combination of sensor inputs. Examples of such user-defined empirical rate estimates can include a decline curve analysis from historic test data, and a combination of asset-defined empirical correlations that are not based on physical models. Table 1 also illustrates a "well-specific rate measurement" as included in the set of well models 27, which refers to those situations for which a flow transmitter FT is present at well W that directly outputs rate and phase information for that well; when present and operable, such direct rate and phase measurement may be taken in preference to the calculated values from the other well models 27.

[0074] As is also evident from this Table 1 of models and inputs, the availability of certain measurements and unavailability of other measurements can result in the selection of one model versus another. For example, if a reliable downhole pressure measurement is available but a reliable wellhead temperature is not available, the tubing model can be used to derive rate and phase values, along with reservoir pressure and wellhead temperature, assuming values for watercut and gas-oil ratio, by matching the rates and phases to DHP. Conversely, if the downhole pressure measurement is not available or reliable, but wellhead temperature can be reliably measured, the tubing model can be used to calculate rate and phase values, along with reservoir pressure and downhole pressure, assuming values for watercut and gas-oil ratio, by matching the rates and phases to WHT. The interplay among the various models not only provides calculations based on the available and reliable measurements, but also can improve the robustness of the rate and phase calculation by confirmation of calculated values among the multiple models, as will be discussed below.

[0075] As evident from the example shown in Table 1, certain model parameter values applied to the models are "assumed" values. These assumed values can be based on well tests or other previously-measured values for those parameters. Or, alternatively, the assumed values for these parameters can be values that were generated by other models, or models for other wells in the production field, or even simply taken from a user input.

[0076] According to an embodiment of this invention, however, these assumed values, which are conventionally considered to be constant values, are expressed as functions. It has been discovered, according to this invention, that mathematical functions can be used in place of certain constants to create a dynamic model. Examples of values that conventional models treats as constants, and that can be evaluated as functions according to embodiments of this invention, include reservoir pressure, productivity index, gas-oil ratio, and watercut. These parameters are illustrated in Table 1 as "assumed" values. According to embodiments of the invention, one or more of these "assumed" parameter values are expressed as a function of time or a function of another parameter. For example, reservoir pressure may be expressed as a function of time or of cumulative production or of both. Watercut may be expressed as a function of time, while productivity index may be expressed as a function of a time variable, and as a function of one or more of rate, watercut or gas-oil ratio. It is contemplated that the functional expressions used for these "assumed" parameters can be readily evaluated for a given application of the model to current measurements; for example, if time is a variable, a timestamp of the measurement data or some other indication of the effective time for which the model calculations are to be performed can be easily applied to the time variable function. For example, if a time-rate of change of reservoir pressure can be estimated from previous calculations, the input parameter value of reservoir pressure into the selected model can be readily calculated from previous measurements and estimates, and used as a current reservoir pressure value for the model along with current pressure and temperature measurements. The "longevity" of previous measurements and thus the longevity of the model itself can be greatly increased. This approach also avoids the need for iterative changes to, or iterative optimization of, the well model, and also greatly assists the providing of accurate rate and phase information on a near-real-time and continuous basis.

[0077] Figure 4 illustrates an example of the construction and architecture of server 8a, according to an embodiment of the invention. The arrangement of server 8a shown in Figure 4 is presented by way of example only, it being understood that the particular architecture of server 8a can vary widely from that shown in Figure 4,

depending on the available technology and on the particular needs of a given installation. Indeed, any conventional server architecture of suitable computational and storage capacity for the volume and frequency of the measurements involved in the operation of this embodiment of the invention can be used to implement server 8. As such, the construction of server 8a shown in Figure 4 is presented at a relatively high level, and is intended merely to illustrate its basic functional components according to one arrangement.

[0078] In this example, communications interface 10 of server 8a is in communications with data acquisition systems 6 at platforms 2. Communications interface 10 is constructed according to the particular technology used for such communication, for example including RF transceiver circuitry for wireless communication, and the appropriate packet handling and modulation/demodulation circuitry for both wired and wireless communications. Communications interface 10 is coupled to bus BUS in server 8a, in the conventional manner, such that the measurement data received from data acquisition systems 6 can be stored in data base 12 (realized by way of conventional disk drive or other mass storage resources, and also by conventional random access memory and other volatile memory for storing intermediate results and the like) under the control of central processing unit 15, or by way of direct memory access. Central processing unit 15 in Figure 4 refers to the data processing capability of server 8a, and as such may be implemented by one or more CPU cores, co-processing circuitry, and the like within server 8a, executing software routines stored in program memory 14 or accessible over network interface 16 (*i.e.*, if executing a web-based or other remote application). Program memory 14 may also be realized by mass storage or random access memory resources, in the conventional manner, and may in fact be combined with data base 12 within the same physical resource and memory address space, depending on the architecture of server 8a.

[0079] Server 8a is accessible to remote access terminals RA via network interface 16, with remote access terminals RA residing on a local area network, or a wide area network such as the Internet, or both (as shown in Figure 4). In addition, according to this embodiment of the invention, server 8a communicates with another server 8b via

network interface 16, either by way of a local area network or via the Internet. Server 8b may be similarly constructed as server 8a described above, or may be constructed according to some other conventional server architecture as known in the art; in any event, it is contemplated that server 8b will include a central processing unit or other programmable logic or processor, and program memory or some other capability for storing or acquiring program instructions according to which its operation is controlled. As will be described in further detail below, servers 8a, 8b are arranged to operate different software components from one another, according to this embodiment of the invention. As mentioned above and as will be apparent to those skilled in the art having reference to this specification, servers 8a, 8b may be realized by many variations and alternative architectures, including both centrally-located and distributed architectures, to that shown in Figure 4 and described above.

[0080] Figure 5 illustrates an example of a software architecture realized at servers 8a, 8b, and remote access terminals RA, by way of which the monitoring system of this embodiment of the invention is realized. The software modules and applications illustrated in Figure 5 as being performed by or resident upon a particular computer resource (server 8a, server 8b, remote access terminals RA) are one embodiment of this invention, as this arrangement is believed to be particularly beneficial in the applications and uses of this invention regarding conventional hydrocarbon production fields. It is contemplated that those skilled in the art having reference to this specification may vary the realization of the software architecture of Figure 5, for example by a different arrangement of services 8a, 8b or by realizing more or fewer applications and modules on different ones of the computer resources. It is also contemplated that those skilled in the art having reference to this specification will also comprehend that the software architecture itself can vary from that shown in Figure 5 and described herein, without departing from the scope of the invention.

[0081] It is contemplated that the various software modules illustrated in Figure 5 for implementing the monitoring system of this embodiment of the invention constitute computer software programs or routines, or packages of programs or routines, that are executed by the central processing unit (*e.g.*, central processing unit 15 of server 8a in

Figure 4) of the illustrated computer resource. As such, it is contemplated that these computer software programs illustrated in Figure 5, as well as such higher level programs (not shown) controlling the overall operation of the system, are stored in program memory of each of the computer resources of Figure 5 (*e.g.*, program memory 14 of servicer 8a, as shown in Figure 4), or are otherwise made available to these computer resources. In this regard, it is contemplated that these computer programs, packages, modules, and software systems may be provided to the computer resources of Figure 5 by way of computer-readable media, or otherwise stored in program memory or other conventional optical, magnetic, or other storage resources at those computer resources, or communicated thereto by way of an electromagnetic carrier signal upon which functional descriptive material corresponding to these computer programs is encoded. In addition, it is contemplated that the location at which one or more of these computer programs is resident may be different from the computer resource executing that computer program, such as in the case of the so-called "web-based" application programs. These and other variations on the hardware and software architecture of this embodiment of the invention are contemplated to be within the scope of the invention as hereinafter claimed, as will be recognized by the skilled reader of this specification.

[0082] As shown in Figure 5, server 8a includes one or more data historian software modules 20. These data historian software modules 20 manage the storage of incoming measurement data from data acquisition systems 6 at platforms 2, in the example of Figure 1, as well as the storage and access of these incoming measurement data by the other software modules of the architecture of Figure 5. In addition, data historian modules 20 also manage the storage of rate, phase, operating state, and other reservoir performance parameters determined by the monitoring system according to this embodiment of the invention.

[0083] Server 8a also executes interface module 22, which communicates with remote access terminals RA via web service functions 23. Each web service function 23 at server 8a, and elsewhere in this system, is realized by a conventional software system that supports interoperable machine to machine interaction over the network, and may be realized by way of a web application program interface, for example by handling XML

messages, as known in the art. Interface module 22 provides user access to the monitoring system of an embodiment of the invention, for example by way of web browser application 25 running on a client remote access terminal RA as shown in Figure 5. Interface module 22 thus responds to HTTP commands from client remote access terminal R, received via the corresponding web service 23, and generates the corresponding web page or other interactive display of field data, calculated parameters, and other information requested by the human user. Web browser application 25 is contemplated to be the primary output module to the human operator, for purposes of monitoring the well and reservoir assets, according to this embodiment of the invention.

[0084] In addition, another web service 23 associated with interface module 22 at server 8a communicates with model verification application 26, also resident or executing at client remote access terminal RA. As will be described in further detail below, in this embodiment of the invention, model verification application 26 is a standalone application that permits the human user (*e.g.*, petroleum engineer, reservoir engineer, geologist, operator, technician, or other user or operator) to manage the well models used by the monitoring system of embodiments of the invention, to verify the model results as produced by the monitoring system, upload new or updated models into the system, and otherwise maintain the models used by the system. While this specification refers primarily to human users, it is contemplated that the users can also be non-human users comprised of computers or other equipment capable of receiving, analyzing, and arriving at a decision or plan of action, which can then be transmitted or otherwise input into the system. Verification and adjustment of these well models and reservoir models can be carried out by the human operator via model verification application 26. This verification and adjustment can be based on actual data acquired from the field, for example by downhole pressure transducers PT and wellhead transducers WPT, WTT, FT as shown in Figure 1; in addition, extrinsic data from well tests and the like may also be input by the human operator, and used in model verification application 26 to so verify and adjust the current well models. As evident from Figure 5, model verification application 26 preferably has access to its own well model 27, or well model package, as useful in such verification.

[0085] According to an embodiment of this invention, server 8a includes flow test monitor module 85, as shown in Figure 5. As will be described in further detail below, flow test monitor module 85 receives and processes measurements obtained during flow tests of individual wells supported by servers 8. This processing includes analysis of the flow test measurements to determine whether the measurement data are of sufficient quality and stability that valid conclusions can be drawn from the flow test. Flow test monitor module 85 also interfaces with data historians 20 for storage of the flow test results. These flow test measurements and data stored by data historians 20 can also be communicated to a user via interface 22 and web service 23, for display in a window of web browser 25 at a client remote access terminal RA, as shown in Figure 5. A more detailed description of the processing by flow test monitor 85 and the display of flow test results will be provided below. Furthermore, as shown in Figure 5, flow test monitor 85 also receives signals from the production field, specifically including signals indicating that the output from one or more wells has been routed to a flow meter or other measuring device, which initiates data gathering and processing of the flow test measurements by flow test monitor module 85.

[0086] Server 8a also executes calculation scheduler module 24 in this embodiment of the invention. Calculation scheduler module 24 is a software module or package that processes the measurement data stored in database 12 of server 8a, under the control of data historians 20. The processing of this measurement data includes such filtering or smoothing as desired by the monitoring system, as may be indicated by other modules in the system itself, or as may be indicated by user input. In addition, calculation scheduler module 24 also initiates pre-scheduled monitoring analysis, according to this embodiment of the invention, by way of which monitoring of rate, phase, operating mode, etc. of one or more wells W is carried out periodically and automatically, without requiring user initiation or invocation.

[0087] The monitoring system of this embodiment of the invention also includes one or more online servers 8b on which the various predictive well models reside and are executed, in response to current and stored measurements for a given well W forwarded from server 8a. In this example of the software architecture of the system as illustrated in

Figure 5, online server 8b includes model service manager module 30, which interfaces with server 8a by way of web service function 23, and which itself is an application that executes the calculations in an automated manner, based on one or more selected well models 27, upon request by calculation scheduler module 24 of server 8a, and upon data communicated thereto by server 8a, such data including temperature and pressure measurements acquired from a well W and associated with a particular point in time, along with other information including assumed or evaluated model parameters and the like. Model calculations executed by model service manager module 30 can also be requested by model verification application 26 of client remote access terminal RA. According to this architecture, model service modules 32 also reside at online server 8b, with web service modules 23 as interfaces, and operate to execute well models 27 in a "co-processor" manner, instantiated by model service manager module 30 in server 8b. In this architecture, multiple model service modules 32 are provided, each capable of applying a selected one of well models 27 to a data set, all under the management of model service manager 30. A single instance of model service manager module 30 can manage multiple instances of model service modules 32; it is contemplated that model service manager module 30 can select and associated any one of the available well models 27 for each of the model service modules 32 that it is managing. Upon evaluation of well models 27 by model service manager module 30 and model service modules 32, the results, including rate and phase calculations and the like, are communicated from server 8b back to server 8a, over the network.

[0088] According to an embodiment of the invention, server 8b also includes flow test software module 80, which is also associated with a corresponding web service module 23 as an interface between flow test module 80 and other software modules in the system. As will be described in further detail below, flow test module 80 receives recent and historical flow test data from server 8a, under the control of calculation scheduler 24 or the like, and manages the calibration and updating of well models 27 based on the result of such flow tests. Validation of updates to well models 27 as a result of flow tests can be carried out by a reservoir engineer or other user via model verification application 26, which interfaces with flow test module 80 via its web service 23 in this architecture.

Flow test module 80 is also in communication with model service manager 30, by way of which it can initiate evaluation of one or more well models 27 for purposes of calibration or verification, relative to recently received well test measurements, as will be described below. In addition, flow test module 80 can include functionality for intelligently scheduling future flow tests for the production field, and communicating the derived schedules to interested users, such as the petroleum engineers and reservoir engineers, as will also be described below.

[0089] While the software architecture according to an embodiment of the invention is described above for a single asset, this architecture is readily adaptable to a multiple-asset environment, covering multiple platforms 2 within a given production field, or wells located in multiple separate production fields, if desired. Figure 6 illustrates the software architecture of online server 8b as deployed for a multiple-asset implementation. In this example, multiple instances of model service manager modules 30a through 30c are instantiated at online server 8b, each in communication with one or more calculation scheduler modules 24a through 24d at corresponding ones of multiple servers 8a. In this example, calculation scheduler 24a is in communication with model service manager module 30a, and is monitoring rate and phase information for two assets ("A" and "B"). Two calculation schedulers 24b, 24c are in communication with another instantiation at online server 8b, namely model service manager module 30b; calculation scheduler 24b and calculation scheduler 24c carry out the rate and phase monitoring for separate assets ("C" and "D", respectively). Calculation scheduler 24d is in communication with a third model service manager module 30c at online server 8b, for purposes of monitoring yet another production asset ("E").

[0090] In this multiple-asset realization, each of model service manager modules 30a, 30b, 30c can manage any one of model service modules 32, and indeed can manage multiple model service modules 32 if required to carry out its tasks. Conversely, each of model service modules 32 can service any one of model service manager modules 30a, 30b, 30c. In each case, model service manager modules 30a, 30b, 30c select and manage the particular well model 27 used by the model service modules 32 that it manages.

[0091] Referring back to Figure 5, an additional remote access terminal RA is illustrated as supporting and executing administration application 28, in combination with a selected well model 27. This remote access terminal RA executing administration application 28 is in the role of an administrator for the system and as such, in this example of an embodiment of the invention, has access to model service manager module 30 and each of model service modules 30 resident at online server 8b, and to flow test module 80. Under the operation of a human operator, administration application 28 monitors and troubleshoots model service manager module 30 and each of model service modules 30, as well as flow test module 80. For example, operational logs of model service manager module 30 and model service modules 30 can be reviewed, and the operational results of those modules 30, 32, can be reviewed and analyzed by the human operator. Configurations of model service manager module 30 and model service modules 30 at online server 8b can be amended via administration application 28. Specific calculation requests by a selected one of model service manager module 30 and model service modules 30 can also be made by administration application 28, as may be useful in connection with the monitoring system of this embodiment of the invention.

[0092] Referring now to Figure 7, the general operation of the rate and phase monitoring system described above, according to an embodiment of the invention, will now be described. It is contemplated that the operations of Figure 7, as illustrated in that Figure and in the more detailed Figures described herein, are carried out by the execution of computer programs by the central processing units and other programmable logic in the various computing resources shown in the example of Figure 4, using the software architecture described above in connection with Figures 5 and 6. It is further contemplated that these computer programs can be readily created by those skilled in the art having reference to this specification, from the functional descriptions provided in this specification, using conventional programming skill and technique in combination with existing software packages as appropriate, and without undue experimentation. It is also contemplated that those skilled readers can vary this operation from that described in this specification without departing from the scope of the invention as claimed. Accordingly,

this operation of the monitoring system according to this embodiment of the invention is described by way of example only.

[0093] Data from one or more wells W in a field are collected and fed in a near-real-time fashion to calculation process 35. This "near-real-time" data collection refers to the measurements being acquired during operation of each monitored well W at relatively frequent intervals (*e.g.*, as often as once per second), with the data corresponding to those measurements associated with a time of collection by data acquisition systems 6, and the time-associated data forwarded to servers 8 (Figure 1). It is contemplated that this forwarding of acquired data by data acquisition systems 6, to servers 8, will be relatively frequent, but not necessarily on a measurement-by-measurement basis. For example, current-day downhole and wellhead transducers acquire measurements as frequently as once per second. It is contemplated that data acquisition systems 6 will obtain and process those measurements for a given well over some time interval and thus periodically forward those processed measurements for the interval to servers 8. For example, it is contemplated that the forwarding of acquired data to servers 8 will occur on the order of a few times a minute (*e.g.*, every fifteen seconds). As will be described in further detail below, calculation process 35 applies these received measurement data to one or more models to estimate rate and phase, and operating state.

[0094] It is also contemplated that calculation process 35 will likely not be performed for a given well W each time that data acquisition systems 6 forward data to servers 8 for that well W. Rather, it is contemplated that calculation process 35 will be performed periodically, for example at a period selected or determined by a human user. For example, it is contemplated that, for many applications, the frequency with which calculation process 35 is carried out will vary from as frequently as on the order of about once every five minutes, to on the order of about once every one or two hours. However, it is contemplated that the monitoring of this embodiment of the invention is "continuous", in that this operation of calculation process 35 proceeds in an automated manner, according to such a selected frequency or periodicity, without requiring initiation by a human user. Of course, it is also contemplated that a human user can initiate

calculation process 35 "on demand", separately from its continuous operation in this manner.

[0095] Figure 8 illustrates the operation of calculation process 35 in further detail. Each instance of rate and phase calculation process 35 begins with process 48, in which server 8a collects data from well W and database 12. In particular, referring to the architecture of Figure 5, calculation scheduler module 24 manages data collection process 48, in cooperation with data historian modules 20. According to this embodiment of the invention, the measurement data collected in data collection process 48 can include data corresponding to measurements of pressure and temperature at the wellhead, measurements of downhole pressure and temperature, measurements of pressure and temperature upstream and downstream of the wellhead control valve or valves (choke and gaslift), the position of wellhead control valves (choke and gaslift), and properties of fluid samples. Of course, not all of these measurements will be available from every well W, or at all times. In addition, it is contemplated that the frequency with which these measurements are acquired will vary from measurement to measurement.

[0096] In conventional monitoring of hydrocarbon wells, sensor data is typically interpreted as unchanged unless it changes more than a specified amount – a process often referred to as "dead-banding". Dead-banding is often useful because it can reduce the necessary data transmission capability of the system, or reduce the volume of data transmitted, or simply in maintaining a "legacy" approach to the monitoring. However, dead-banding inherently limits the resolution of sensors, and can also have the effect of masking the actual performance of the sensors. As such, in this embodiment of the invention, sensor measurement data is collected in process 48 without such dead-banding. This non-deadbanding approach enables predictive well models 27 to compensate for inaccurate sensors, or even calibrate the output from the inaccurate sensors, as will be described below.

[0097] In addition, data collection process 48 acquires current estimates of certain well and reservoir parameters from database 12, via data historian modules 20. As shown in Figure 8, database 12 stores rate and phase values that have been previously calculated

for wells W, for example in database entries such as entry $E_{W,j}$. In this example, entry $E_{W,j}$ includes stored values for rate and phase, along with an identifier of the well for which those rate and phase values correspond, and a timestamp indicating the time (including date) of the measurements to which those rate and phase correspond. Other information, including measured, assumed, and calculated values, may also be included in each entry $E_{W,j}$ in database 12. As such, in data collection process 48, the current estimates of well and reservoir parameters for well W that are to be applied to the next rate and phase calculation instance are retrieved from one or more corresponding entries $E_{W,j}$. The current estimates retrieved from database 12 for well W in process 48 include the most recently calculated or otherwise estimated phase conditions for the flow from well W (*e.g.*, watercut, gas-oil ratio, etc.), and reservoir performance (*e.g.*, reservoir pressure, productivity index, etc.) of the reservoir into which well W is deployed. According to this embodiment of this invention, one or more of these current estimates can be derived by evaluating a function, rather than by adopting an assumed value. As known in the art, conventional well models operate on the assumption that certain parameters can be expressed constants for a given well W, or over a particular reservoir. Examples of values that these conventional well models typically treat as constants include reservoir pressure, productivity index, gas-oil ratio, and water cut, as evident from Table 1 described above (*i.e.*, in connection with the parameter values indicated as "AS", meaning "assumed" values). As such, these conventional well models typically operate at a "snapshot" point in time, applying the most recent measurements from well tests, values determined by other modeling systems, and the like to the model, along with the assumed constants.

[0098] The monitoring system and method according to this embodiment of the invention, however, is intended to operate in a near-real-time manner, based on the relatively high frequency with which new downhole and wellhead measurements can be obtained. But not all parameter values are obtained at each measurement point in time, nor are estimates calculated for each point in time at which measurements are obtained, even though the conditions of well W being monitored may be changing over time or as production continues. According to this embodiment of the invention, therefore, one or

more of the "assumed" values applied to well models 27 is expressed as a function, rather than as a constant, and that function is evaluated at the point in time, or in cumulative production quantity, or the like corresponding to the time at which the current measurements were acquired. Some of these parameters that can be expressed as a function rather than a constant include reservoir pressure, which may be expressed as a function of time or of cumulative production or both; productivity index, which may be expressed as a function of time; and one or more of the parameters of flow rate, water cut, or gas-oil ratio, each of which may be expressed as a function of time or cumulative production quantity. For example, if reservoir pressure at a given well W has been observed to be decreasing over time, based on well test results or even on the recent history output by the monitoring system of this embodiment of the invention, the observed time-rate-of-change of reservoir pressure can be used to derive a time-based function for reservoir pressure (by way of extrapolation), in effect predicting the reservoir pressure at a current point in time based on those past observed trends. The functions may be relatively simple linear functions of time or cumulative production quantity, as the case may be, or may be expressed as higher-order functions if desired and if useful in improving the accuracy of the evaluated result. By treating these parameters as functions in this manner, the "longevity" of the well models can be extended, such that the accuracy of these models as currently configured can continue for a substantial time without additional well tests and the like. In any case, the evaluated results of these functions are then collected by process 48, in lieu of assumed constant values, and applied to the well models 27 in the manner described below, to derive rate and phase estimates.

[0099] Once these data and estimates are collected in process 48, server 8a next performs process 50 to determine the current operating state of well W based on these measurements. It is contemplated that the particular well models to which the collected measurement data are applied are preferably selected according to the current operating state of well W. For example, certain hydraulics well models may be more suitable for use in steady-state production, while other hydraulics well models may be more suitable during the transient period following start-up of production. In addition, these well

models may depend on the particular well W itself, or perhaps on previously observed characteristics of the production field at which well W is located. For example, the phase composition of the fluid from a well W may be dominated by gas for a few hours following startup (during which certain well models may be more appropriate), but may have little or no gas phase thereafter (during which other well models may be more appropriate, and during which other parameters such as water composition may be more important). As such, according to this embodiment of the invention, process 50 determines the current well operating state of well W.

[0100] With reference to Figure 5, it is contemplated that this process 50 will be executed by server 8a as part of calculation scheduler module 24. This determination of current operating state for well W is performed by calculation scheduler module 24 in combination with model service manager module 30 and model service module 32, based on the most recent measurements obtained from well W and stored by data historian modules 20, as will now be described with reference to Figure 12, by way of example. In general, the measurements utilized in this determination of operating state include the positions of choke valve 7 and other valves at wellhead 9, and the variation over recent time of pressure and temperature measurements at well W.

[0101] In the example of Figure 12, five potential operating states S1 through S5 for well W are illustrated, along with conditions that can cause a transition from one state to another. Steady-state shut-in state S1 corresponds to a well W through which no flow is passing, while steady-state producing (or injecting) state S2 corresponds to the state in which well W is passing fluid in a relatively steady-state. The steady-state states S1, S2 can be initially detected, in this process 50, based on the position of choke valve 7 or other valves in the production flowline of well W; if any one of those valves is sensed to be in a closed position, steady-state shut-in state S1 is detected, because of the absence of flow necessarily resulting in that condition. Conversely, if choke valve 7 and all other valves in the flowline are open, steady-state producing state S2 can be entered. As evident in Figure 12, steady-state producing state S2 can also apply to well W being used as an injecting well; the distinction between producing and injecting steady-state

conditions is preferably made based on identifying information stored *a priori* for well W in database 12.

[0102] Transient start-up state S3 corresponds to the state of well W as it makes the operational transition from the steady-state shut-in state S1 to steady-state producing state S2. According to this embodiment of the invention, transient start-up state S3 is detected in process 50 based on calculations made according to a predictive well model 27 under the control of model service manager 30 or model service module 32, called by calculation scheduler module 24, based on the applying of the pressure and temperature measurements at well W to one or more predictive well models 27. The manner in which such well models 27 derive rate and phase information will be described in further detail below. Also according to this embodiment of the invention, changes in these temperature and pressure measurements over time can indicate the presence of fluid flow through well W. The detection of increasing flow, by way of changes in these pressure and temperature measurements over recent time, thus causes a transition in the operating state of well W from steady-state shut-in state S1 to transient start-up state S3, and detected in process 50. Similarly, based on the pressure and temperature measurements as applied to predictive well models 27 for well W indicating, over recent time, that a non-zero flow is present but is not substantially changing, a transition from transient start-up state S3 to steady-state producing state S2 occurs, and is detected in process 50.

[0103] Conversely, transition from steady-state producing state S2 to transient shutting-in state S4 can be detected, in process 50, by the pressure and temperature measurements for well W indicating, over recent time and by way of one or more predictive well models 27, that the fluid flow through well W is reducing. If these pressure and temperature measurements and well models indicate that there is no flow at all through well W (despite all valves being open), a transition directly from steady-state producing state S2 to steady-state shut-in state S1 can be detected in process 50. This condition can exist if an obstruction becomes lodged somewhere in well W or its production flowline. Finally, the transition from transient shutting-in state S4 to steady-state shut-in state S1 is detected, in process 50, by either the pressure and temperature measurements indicating no flow through well W, or by detection of the closing of at

least one valve in the production flowline. Conversely, if the flow stabilizes, albeit at a lower level than previously, as indicated by pressure and temperature measurements monitored over time in process 50, a transition back to steady-state producing state S2 can be detected.

[0104] Finally, various error or abnormal flow conditions can also be detected by operation of process 50, in which the operating state or mode of well W is detected according to this embodiment of the invention. As known in the art, the term "slugging" refers to the condition of a well in which one phase builds up rapidly in flow volume; this transient can induce surges in the slugging well itself, and also in neighboring wells in the production field. Figure 12 illustrates slugging state S5, which can be detected according to this embodiment of the invention, by application of pressure and temperature measurements to one or more predictive well models, by way of which the calculated rate and phase information indicates a build-up of one phase relative to the others; detection of this condition over recent time causes a transition to slugging state S5, which is detected in process 50. Conversely, a transition from slugging state S5 back to steady-state producing state S2 can be detected upon sensing stable rate and phase values over recent time, based on application of temperature and pressure measurements for well W to the predictive well models.

[0105] In this manner, the operating state of a given well W is detected in an automated manner, from valve position signals and also measurements of pressure and temperature downhole or at the wellhead or both, at that well W. As discussed above, selection of the particular well models 27 to which the collected measurement data are to be applied may depend on the operating state of well W that is detected in process 50, and also on certain characteristics of well W that have been previously observed or assumed (such characteristics stored in database 12 or otherwise known by calculation scheduler module 24 for well W). As such, the operating state of well W is retained upon completion of process 50, following which control passes to decision 51.

[0106] As will be evident from the following description, the computational effort required for calculating rate and phase using multiple models can be substantial.

According to this embodiment of the invention, previous results of the rate and phase calculations are "cached" in a memory resource, for example database 12, so that the computational effort of evaluating the models can be avoided if the received data is not substantially different from the previous calculation for that same well W. Calculation scheduler module 24 in server 8a thus executes decision 51 to determine whether the most recent set of measurement data acquired in process 48 has substantially changed from one or more recent calculations of rate and phase. Especially considering that the rate and phase determination according to this invention is intended to approach near-real-time monitoring, decision 51 analyzes the data collected in process 48, including both the recently obtained measurement data from well W and also the most recent current estimates from database 12, to determine whether the value of any parameter in this most recent data has changed, relative to previous values, by more than a threshold amount or percentage. It is contemplated that the particular change threshold for a given measurement can be initially set to a default level, and thereafter modified by a human operator, for example via administration application 28 or model verification application 26. However set, the threshold amount or percentage should correspond to a relatively small change in a parameter value, to ensure that such a small change in the parameter value will not affect the calculated rate and phase results. The comparisons of decision 51 can be performed between the received measurement and the single most recent measurement value, or alternatively the comparisons can be made in a weighted manner relative to a series of recent measurements. As mentioned above, the threshold can be based on a percentage change in the measurement value, or alternatively on an absolute measure of the particular parameter. If no measured (and compared) parameter has changed its value by more than the threshold amount (decision 51 is NO), the previous rate and phase results are stored again in database 12, preferably by way of a new entry $E_{W,t}$ in which the same rate and phase values, and other information, are stored in association with the indicator for well W and a current time-stamp value corresponding to the time at which the rate and phase estimates are to correspond (*i.e.*, a time corresponding to that at which the measurements were taken).

[0107] On the other hand, if one or more measured parameters have sufficiently changed in value to exceed the respective threshold amount (decision 51 is YES), then one or more predictive well models 27 are to be evaluated based on the newly received measurement data gathered in process 48. As shown in Figure 8, this well model calculation is carried out by calculation control algorithm 52, through the use of well models 27. As described above relative to Figures 5 and 6, it is contemplated that calculation control algorithm 52 will be executed by calculation scheduler 24, resident in server 8a, calling or instantiating model service manager 30 in online server 8b, which itself applies the data collected in process 48 (and communicated thereto from server 8a) to one or more well models 27, and which also calls or instantiates one or more model service modules 32 to also evaluate well models 27 upon that collected data, as necessary for efficient operation. The results of the evaluation can then be returned back to server 8a from server 8b, according to the example of the architecture illustrated in Figures 4 and 5; it is to be understood, of course, that the communication of data and results will vary as necessary and appropriate for the particular system hardware and software architecture used to carry out the monitoring functions of this invention.

[0108] In general, as evident from Figure 8, it is contemplated that the received and collected data from process 48 will be applied to more than one well model 27, each such well model 27 generating rate and phase result output, from which a determination of the most accurate calculation will be performed in process 54. The well models 27 to which these data are applied may be selected based on the operating state of well W detected in process 50, as mentioned above. In any event, according to this multiple-model approach, it is contemplated that model service manager 30 will typically involve one or more instances of model service module 32, and corresponding well models 27, to efficiently carry out the calculation of rate and phase.

[0109] Examples of the evaluation of well models 27 with measured data, in process 52, will be instructive. Table 1 discussed above provides a good universe of choke and hydraulic well models 27 that can be used in connection with process 52, according to an embodiment of the invention, although it is of course contemplated that additional or different well models may also be used.

[0110] Figure 9 illustrates calculation process 52a, by way of which a conventional Perkins differential pressure choke model is evaluated using data collected in process 48. As mentioned above, calculation process 52a is carried out by one of model service manager 30 or model service module 32, executing a corresponding computer program or routine using well model 27 corresponding to this differential pressure choke model. In process 60, the fluid properties are calculated, based on the measurement data corresponding to pressure upstream of choke valve 7 (*e.g.*, measured by wellhead pressure transducer WPT), pressure downstream of choke valve 7 (*e.g.*, as measured by downstream choke pressure transducer DCPT), and temperature upstream of choke valve 7 (*e.g.*, measured by wellhead temperature transducer WTT). The result of process 60 is an estimate of the phase composition (oil, gas, water) of the fluid flowing through choke valve 7.

[0111] An iterative procedure is next carried out, beginning with process 62 in which a first estimate of the flow rate through choke valve 7 is made, based on previous information. Then, in process 64, an estimate of the pressure drop across choke valve 7 is derived, using a conventional multiphase model (such as a Perkins differential pressure choke model for well W) to which the diameter of the choke opening (*e.g.*, calculated from stored geometric parameters for the specific choke valve 7 at well W, in combination with the current choke position measured by choke valve position transducer CPT), and the estimates of phase composition and flow rate are applied. In decision 65, the resulting calculated differential pressure from process 60 is then compared against the measured differential pressure (*i.e.*, the difference between the measured pressures upstream and downstream of choke valve 7 applied to process 60. If these pressure values differ from one another by more than a threshold amount (decision 65 is NO), the current estimate of the flow rate is adjusted in process 66, and a new pressure drop is calculated based on this adjusted flow rate, in process 64, and decision 65 is repeated. Upon the calculated pressure drop from the multiphase model being sufficiently close to the measured pressure drop (decision 65 is YES), model service manager 30 returns the current estimates of flow rate and phase to calculation scheduler module 24 in server 8a, in process 68.

[0112] As mentioned above, more than one well model 27 is applied to the collected measurement data in process 52, according to an embodiment of the invention. In this example, in addition to the choke model described above relative to Figure 9, one or more hydraulics models, such as those described above in connection with Table 1, may be used. For example, application of the collected measurement data to a hydraulic model such as that described above relative to Figure 3 can be performed by process 52. As described above relative to Table 1, these hydraulics models can include models of inflow and tubing, in which the rate and phase estimates are matched to downhole pressure, or wellhead temperature, or another measurement, based on an estimate of reservoir pressure; these hydraulics models also include tubing-only models, in which the rate and phase estimates are matched against both downhole pressure and wellhead temperature, for example, and from which a reservoir pressure estimate can be derived. And, for these inflow-and-tubing and tubing-only models, variations can be applied to select a particular parameter that is adjusted to match the downhole pressure or wellhead temperature, such parameters including gas-oil ratio (or condensate-gas ratio), watercut, and gaslift (where applicable). Other *ad hoc* user-defined models and equations can also evaluate the measurement data in process 52.

[0113] Another example of the application of well model 27 is illustrated graphically in Figures 10a and 10b. In this example, reliable measurements of downhole pressure, wellhead pressure, and wellhead temperature have been obtained for a producing oil well W, for which water cut is assumed to be known and unchanging. According to one of the well models 27, the production rate and the gas-oil ratio, GOR, of the produced fluid can be obtained. Figures 10a and 10b are graphic representations illustrative of output from a calibrated predictive hydraulic well model 27 suitable for this well W using these measurements, such a model corresponding to an inflow-and-tubing model, adjusted for GOR, and matched to wellhead temperature. Figure 10a shows downhole fluid pressure as a function of fluid rate for a range of constant GOR values, according to this well model 27, while Figure 10b shows the resulting predicted fluid temperature at the wellhead as a function of the same fluid rate and GOR values, also according to this predictive well model 27. As shown in Figures 10a and 10b, this

predictive well model illustrates that, for constant GOR, the wellhead temperature normally rises significantly with increasing production rate while the downhole gauge pressure will also rise for rates high enough for stable flow, and that, for a constant production rate, the downhole pressure will fall with increasing GOR while the wellhead temperature changes only very little.

[0114] In this embodiment of the invention, numerical techniques are applied to determine the combination of production rate and GOR that correspond to the measured downhole gauge pressure and wellhead temperature. For instance, a measurement of downhole pressure at 50 barg in combination with a measurement of wellhead temperature at 25°C will yield rate and phase values of 7500 STB/d and 650 scf/STB, respectively.

[0115] In the examples discussed above, the absolute measurement values obtained from the various sensors and transducers are applied to predictive well models 27 to derive rate and phase values. Alternatively, predictive well models 27 could also be included that calculate changes in production rate and phase from detected changes in sensor readings, rather than the absolute measurement values. One advantage to such change calculations is that readings from sensors which are no longer calibrated correctly can still be used in these change calculation well models 27. As mentioned above, "dead-banding" of measurements is not necessary in connection with embodiments of this invention; according to this alternative approach of carrying out change calculations, such dead-banding would in fact mask changes in sensor readings, and thus would be detrimental if applied in these differential models.

[0116] Once all appropriate estimates of rate and phase values are determined by calculation control algorithm 52, from multiple well models 27 as described above, the monitoring process according to an embodiment of the invention selects or derives a final rate and phase result from those estimates, in process 54. According to that embodiment of this invention, well models 27 are assigned a hierarchy based on the particular conditions for which a given model is most appropriate. For example, a first well model using readings from four sensors may be used to calculate rate and phase, but a different

well model may be preferable if only three of those four sensors are functioning properly. As a further example, a particular well model may be used in a near steady-state scenario, while the system employs a different well model under different performance criteria. In some cases, operator inputs, or inputs triggered by operator decisions, may alter the particular well model that is used. For example, a particular well model may be used if all chokes and valves are fully open, and a different well model may be used when certain valves are closed or partly closed. Beyond selection of a particular well model to use its rate and phase estimates, rate and phase estimates from different well models may alternatively be combined to provide a composite estimate of rate and phase for an increment of time, based on the state of wells W or surface facilities.

[0117] Many variations in the selection or hierarchy of well models are available. For example, certain simple approximations from user-defined equations may be used in place of any of the well models if data is unavailable. For example, while a predictive well model that calculates rate and phase information from at least three sensor inputs is favored in general, a model in which the measurement from a sensor is approximated or assumed may serve as a backup if only two sensor readings are available. Alternatively, a particular well model may be selected if a reading from a specific sensor changes by more than a predetermined amount in comparison to changes in other sensor readings. The effects of a less accurate result through use of these approximations or backup models are reduced because of the frequency with which rate and phase estimates are made according to embodiments of this invention. As such, the use of multiple models renders the monitoring of a well or wells more tolerant of condition changes, sensor failures, or anomalous data.

[0118] Referring now to Figure 11, the operation of process 54, in which the results from these well models 27 are analyzed and final estimates of rate and phase are selected or derived, will now be described in further detail. In process 70, calculation scheduler module 24 executes a software routine to analyze the reliability of measurement data as collected in process 48 discussed above. It is contemplated that analysis process 70 can be carried out according to a wide range of techniques. For example, each measurement value can be compared with a range of expected values, in

order to screen out measurements that have obviously invalid data, such as may result from a transducer or other sensor failing or inoperable. In addition, or alternatively, each measurement value can be statistically compared against its previous measurements over time, to determine whether the current measurement is stable or varying over time. In a more sophisticated approach, a comparison of the current measurement for a given transducer relative to what other transducers associated with well W are measuring, using a simplified model or the like, can indicate whether that measurement is realistic for the conditions.

[0119] It is contemplated that those skilled in the art having reference to this specification can readily apply these and other analysis techniques to determine the reliability of each of the applied measurements, in this process 70 according to an embodiment of the invention.

[0120] Upon completing analysis process 70, calculation scheduler module 24 carries out decisions 71a through 71c by way of which a hierarchy of the well models 27 is derived. In this example, decision 71a determines whether any phase parameter (*e.g.*, gas-oil ratio, watercut, gaslift rate) is varying (and thus not stable) or anomalous. If so (decision 71a is YES), the choke models evaluated in process 52 are downgraded from the standpoint of hierarchy in process 72a, because it is well known that choke models are premised on stable values for these phase parameters. By downgrading, according to this embodiment of the invention, it is contemplated that the downgraded well models 27 are either disqualified from being used, or have a weighting or other factor adjusted to indicate that their results are likely to be in accurate. Similarly, decision 71b determines whether the downhole pressure measurements are unstable, following the analysis of process 70. If so (decision 71b is YES), then those well models 27 that match the rate and phase estimates to downhole pressure measurements are downgraded in process 72b, and in process 74b, the tubing-only well models 27 are downgraded (as those models match rate and phase to measurements of both wellhead temperature and downhole pressure). And decision 71c determines whether the current estimate of reservoir pressure are unavailable or exhibits time-variation; if so (decision 71c is YES), the

inflow-and-tubing hydraulic well models 27 are downgraded in process 72c, considering that models of that class assume a stable reservoir pressure.

[0121] Upon such downgrading of models as performed by processes 72a, 72b, 74b, 72c, or if such downgrading is unnecessary (one or more of decisions 71a, 71b, 71c returning NO results), calculation scheduler module 24 ranks the executed well models 27 according to these results in process 76, in a manner consistent with the results of this analysis. This ranking can take into account a predetermined hierarchy established for well W. For example, a human operator may have previously established an order in which well model 27 results are to be ranked for this well W; the downgrading of well models 27 performed by processes 72, 74 in this manner may alter that pre-selected order. Alternatively, the analysis and downgrading of process 54 may be used to establish the initial order, taking into account general preferences or other rules (*e.g.*, well models 27 that match rate and phase to wellhead temperature, which are believed to be generally less accurate than those matching rate and phase to downhole pressure, as discussed above). In any case, process 76 produces a hierarchy or selection of well models 27, based on their perceived accuracy.

[0122] Examples of the analysis and downgrading operations in this process 54 will be instructive. For example, a well with non-zero gaslift rate, but for which the gaslift rate measurement has failed or is dubious and which also has a changing reservoir pressure, could produce a hierarchy of well models 27 of: 1) Tubing-only hydraulic model (matched to downhole pressure and wellhead temperature), adjusting gaslift; 2) inflow-and-tubing hydraulic model, matched to downhole pressure, adjusting gaslift; and 3) inflow-and-tubing hydraulic model, matched to wellhead temperature, adjusting gaslift. The hydraulic models ranked 2) and 3) in this case are downgraded from the top-ranked model, because of the variability of reservoir pressure; however, these second- and third-ranked models may be useful as backups. The other hydraulic models and the choke models (see Table 1) are downgraded below these three, because those models assume stable gaslift rate if gaslift is present at the well, as it is in this case. For example, the Perkins Choke model will use an incorrect gas-to-liquids ratio in this situation, and will thus infer an incorrect oil rate from the measured pressure drop across the choke.

[0123] In another example, a well for which the gaslift rate is measured accurately, but that exhibits varying watercut values due to coning from the aquifer or breakthrough from an injector, produces a different hierarchy of well models 27 by application of process 54. If the reservoir pressure is known accurately, the full inflow-and-tubing hydraulic models of Table 1 are available, in addition to the tubing-only models. An example of a possible hierarchy in this situation can be: 1) inflow-and-tubing hydraulic model, matched to downhole pressure, adjusting watercut; 2) tubing-only hydraulic model (matched to both downhole pressure and wellhead temperature), adjusting watercut; and 3) inflow-and-tubing hydraulic model, matched to wellhead temperature, adjusting watercut. Other models would be ranked below these, as their accuracy would be suspect under these conditions.

[0124] Yet another example can be considered, in which there is no wellhead temperature transducer WTT and in which the downhole pressure transducer PT for well W has failed and in which GOR is changing. In this situation, an appropriate hierarchy would be: 1) inflow-and-tubing hydraulic model, matched to wellhead temperature, adjusting GOR; and 2) Perkins choke model. In this case, the tubing-only models cannot be used, as they require a downhole gauge pressure measurement. The Perkins choke method is included to provide a backup to the selected hydraulics model. Other models are not contemplated to produce accurate results in this situation.

[0125] Following the ranking of the hierarchy of well models in process 76, calculation scheduler 24 executes process 78 to derive rate and phase estimates based on the output from well models 27, according to that hierarchy. Process 78 may be executed in various ways. For example, process 78 may simply select the output from well model 27 that is highest in the hierarchy, as suggested above. Or the rate and phase output from this most highly-ranked well model 27 may be selected only if it produces values that are reasonably close to the next-most high ranked model or models. Alternatively, process 78 may compute an average of the highest-ranked well model 27 output values; if desired, a weighted average of rate and phase may be derived, in which the higher-ranked well models 27 are more highly weighted in that average. In any case, the rate and phase values produced by process 78 constitute the output of process 54.

[0126] As discussed above, processes 52 and 54 effectively calculate rate and phase values by applying the collected measurement data to all valid well models 27 (valid well models being those models for which all necessary data are available), with the hierarchy determination of process 54 determining which results to use. Alternatively, process 54 may be performed in whole or in part prior to calculation process 52, to determine the hierarchy of well models 27 to which the measurement data are applied, so that computational capacity can be conserved by not evaluating those well models 27 that are less likely to produce accurate rate and phase information. Further in the alternative, some combination of these two approaches may be followed, with a subset of well models 27 selected prior to calculation process 52, and the calculated results from process 52 then ordered according to a hierarchy in the manner described above.

[0127] As known in the art, transducers and sensors at wells W can experience short term or extended failure, and can experience drift in calibration or even sudden changes. Also, sensor data may occasionally fail to transmit or may not be transmitted properly. In other cases, some sensors may not transmit data as reliably as other sensors. These faults are especially likely for downhole sensors, such as downhole pressure transducers PT. It is contemplated that rate and phase values computed in accordance with this invention are more tolerant of such sensor errors than other systems, considering the hierarchy of well models 27 determined in process 54, and the ability of these models to receive and process over-specified input data. More specifically, some of the predictive well models 27 employ more than the minimum data required for rate and phase determination; conversely, measurement data may be available for parameters that one or more of well models 27 otherwise assume or can calculate. This over-specification of input data to the well models 27 leads to the advantageous use of such additional data to compensate for sensor inaccuracy. Figure 8 illustrates optional process 57, by way of which calculation scheduler module 24 is capable of calibrating or adjusting its output based on the output from one or more well models 27.

[0128] For example, if a wellhead temperature transducer WTT is providing an inaccurate temperature measurement in an absolute sense, but operating in a sufficiently

precise manner that its measurements could be used for rate and phase calculations, the absolute values of its readings will be inconsistent with other data. In accordance with this invention, as described above, data from that particular sensor would not be used in the final rate and phase determination, for example by downgrading its associated well models 27 in the hierarchy determined in process 54. However, in process 57, process module 24 may use the determined rate and phase output from the selected well models 27, in addition to other current measurement data, to calculate what that particular sensor reading value should have been. Process 57 may also use sensor readings and model calculations over time to determine whether the measurement data from the particular suspect sensor can be adjusted by a factor or function to provide the correct output value. In any event, according to this embodiment of the invention, a calibration factor or function can be derived, in optional process 57, by way of which future measurement data from that suspect sensor (*e.g.*, the wellhead temperature transducer WTT) is adjusted, and the adjusted temperature values used in future calculations of rate and phase. It is contemplated that the high frequency with which the rate and phase calculations are contemplated to be performed, calibration process 57 can be accomplished in a relatively short time, for example in a few minutes or less.

[0129] Alternatively, process 57 may be arranged so that well models 27 in the hierarchy calculate the expected values of each sensor assuming the other sensors within the system are correct. These expected values can then be compared against the actual received measurement from individual sensors. For any sensor in which the received measurement is substantially different from its expected value, for example by more than a threshold amount or percentage, that sensor may be flagged as having drifted out of calibration or adjustment, and thus requiring a calibration factor as discussed above. Of course, if the differential is sufficiently large, an indication that this sensor is failed can be stored in database 12 or elsewhere, for use in future monitoring. In this approach, the direct comparison of predicted and measured values for most sensors used in the system, in a near real time and continuous basis, can be used to alert the human operator to instances sensor drift or failure, thus increasing the quality control and assurance on the values generated.

[0130] Referring back to Figure 8, the rate and phase values from process 54 are forwarded, by calculation scheduler module 24 (Figure 5), to data historian modules 20. In process 56, data historian modules 20 manage the storing of these new rate and phase values, as well as the well operating state determined in process 50 if desired, in database 12. As before, storing process 56 preferably creates a new entry $E_{W,i}$ in which the newly calculated rate and phase values, and any such other information resulting from calculation process 35 or otherwise, are stored in association with the indicator for well W and a current time-stamp value to be associated with these rate and phase values from this calculation, to maintain the time base for the estimates. In addition, to the extent that these rate and phase values, or other calculations such as reservoir pressure and the like, are used in functions that are evaluated for the next determination of rate and phase for well W, those functions may optionally be updated at this point, using the newly estimated rate and phase values.

[0131] Referring back to Figure 7, the storing of the time-associated rate and phase values in process 56 completes this instance of calculation process 35. Meanwhile, calculation process 35 is carried out for such other wells W from which current measurement data has been produced, as suggested by the multi-asset software architecture described above in connection with Figure 6. And following the completion of this instance of calculation process 35, it is contemplated that this near-real-time and continuous monitoring process will then begin its next instance, according to the frequency or periodicity previously selected by the human user. And as mentioned above, a next instance of the monitoring process for well 35 may be initiated "on demand" from a user, prior to the normal time at which the next instance would commence in its periodic operation.

[0132] According to this embodiment of this invention, the result of the rate and phase calculations produced by process 35 are managed and used in various ways. As illustrated in Figure 7, validation process 36 receives data from production facilities, for example, export facilities, flowlines, separators or any other production related facility, and validates the calculations from calculation process 35 against those facilities data. Validation process 36 may be performed for each rate and phase calculation for each

well, or may be performed only periodically; in addition, validation process 36 may be performed "on-demand", for example in response to a user or administrator request (Figure 5), or if a particular "event" is detected as will be described below. In general, the rate and phase calculations from process 35 are validated, in process 36, by evaluating the consistency of those calculations and results against the facilities data. In addition, as shown in Figure 7, data from tests conducted on wells within the field can be used to calibrate the models via calibration process 34. For example, production from one or more wells may periodically be routed through test separators to ensure proper calibration of the models used for rate and phase determination. Those wells which have more recently undergone such test separator calibration may be deemed to be more reliable and, therefore may be adjusted to a lesser degree than other wells. This combination of calibration process 34 and validation process 36 reduces errors, and thus provides more reliable and accurate results.

[0133] According to an embodiment of this invention, conventional well flow tests constitute one type of well test useful in calibrating predictive well models 27 via calibration process 34. As discussed above, because the revenue is split among interested participants across the entire production field as a whole, rather than allocated from individual wells, the output of the multiple wells in the field is typically combined and that combined output over the entire field is measured as a whole. This eliminates the need to deploy individual flow meters at each well in the field for economic reasons, resulting in cost and operational savings, but at a cost of losing real-time measurement of the performance of individual wells during operation. According to this embodiment of the invention, periodic flow tests of individual wells are managed in an automated fashion, with a minimum of human intervention, and in a manner that can, if desired, calibrate the predictive well models to accurately reflect the status and performance of individual wells.

[0134] Figure 13 schematically illustrates the arrangement of an example of a producing field, in either the offshore or land-based context. In this example, the production field includes many wells 4, deployed at various locations within the field, from which oil and gas product is produced in the conventional manner. While a number

of wells 4 are illustrated in Figure 13, it is contemplated that modern production fields in connection with which the present invention may be utilized will include many more wells than those wells 4 depicted in Figure 13. In this example, each well 4 is connected to an associated drill site 2 in its locale by way of a pipeline 5. By way of example, eight drill sites 2_0 through 2_7 are illustrated in Figure 13; it is, of course, understood by those in the art that many more than eight drill sites 2 may be deployed within a production field. Each drill site 2 may support many wells 4; for example drill site 2_3 is illustrated in Figure 13 as supporting forty-two wells 4_0 through 4_{41}. Each drill site 2 gathers the output from its associated wells W, and forwards the gathered output to processing facility 9 via one of pipelines SL. Eventually, processing facility 9 is coupled into an output pipeline OUT, which in turn may couple into a larger-scale pipeline facility along with other processing facilities 9.

[0135] Even though production from the field as a whole suffices for economic purposes, knowledge of the output of the individual wells 4 in the field is important from the standpoint of well and reservoir management. Understanding of the output of individual wells, including variations in output from well to well within the field and also variations in output over time, can lend substantial insight to the management of the reservoir and of the individual wells 4. For example, comprehension of the flow from individual wells enables the appropriate reworking and other processes to be timely applied to wells 4 to maximize production. Knowledge of changes in the output of wells 4 along with their locations in the field enables accurate management of the reservoir itself, for example by indicating the parts of the field, and thus the wells 4, that would optimally respond to stimulation, injection, pressure support, and secondary recovery processes. This information will also assist the placement of new wells for maximum return on investment.

[0136] To acquire information regarding the output flow from individual wells 4, as is known in the art, a metering system is provided at one or more locations within the production field. Figure 14 illustrates an example of such a metering system useful in connection with this embodiment of the invention, in this case as may be deployed at drill site 2_3 in the production field of Figure 13. Alternatively, a metering system such as

shown in Figure 14 may be deployed at some other location within the production field at which pipelines 5 from individual wells are available. In the example of Figure 14, pipelines 5_1 through 5_5 from five wells 4_1 through 4_5, respectively, are received by a corresponding pair of valves 84_1 through 84_5 and 86_1 through 86_5, respectively. Specifically, for the case of pipeline 5_1, valve 84_1 connects pipeline 5_1 to manifold 83, and valve 86_1 connects pipeline 5_1 to manifold 81; the other pipelines 5 are similarly associated with their corresponding valves 84, 86. The output of manifold 81 is applied to flow meter 82, the output of which is connected to manifold 83. The output of manifold 83, in the example of Figure 14, is pipeline SL_8, which communicates the output of wells 4_1 through 4_4 toward central processing facility 9.

[0137] In this example, each pipeline 5_1 through 5_5 carries all output phases (gas, oil, water) from its associated well 4_1 through 4_5, and flow meter 82 is a multi-phase flow meter, capable of measuring the flow rates of each of the gas, oil, and water phases. Alternatively, a phase separator may be included at some upstream point if flow meter 82 is a single phase meter; in this case, separate flow meters would likely be provided for each of the phases to be measured.

[0138] During normal production operation, all of valves 84_1 through 84_5 are open, and all of valves 86_1 through 86_5 are closed. This routes the output of wells 4_1 through 4_5 directly to manifold 83 and pipeline SL_8; flow meter 82 is measuring no flow at that point. By closing one of valves 84 and opening its corresponding valve 86, the output of the corresponding well 4 can be measured by flow meter 82. For example, if valve 84_2 is closed and corresponding valve 86_2 is opened, the output from well 4_2 is routed to flow meter 82, and from flow meter 82 to manifold 83 and eventually pipeline SL_8. This arrangement is commonly referred to as a "flow test", in this case of well 4_2. According to this embodiment of the invention, valves 84, 86 or other routing hardware indicates a change in routing or position, and the new routing effected by valves 84, 86, to server 8a directly or via some intermediate signal function, to indicate that a flow test is being performed and that measurements from flow meter 82 are forthcoming.

[0139] Such flow tests are typically performed periodically (*e.g.*, on the order of monthly) or in response to a particular event, or suspicion on the part of a user, such as a reservoir engineer. Such flow tests typically are carried out over several hours, to ensure that the measurements are obtained during stable well conditions. As known in the art, during a flow test in which the output of an individual well 4 is being measured, other parameters for that well 4 are also measured. As described above relative to Figures 1 and 2, these parameters include downhole pressure, downhole temperature, wellhead pressure, wellhead temperature, choke valve position, and, if applicable, such other parameters as gas lift pressure, gas lift flow, gaslift control valve position, and the like. The flow test of well 4 is thus able to correlate the flow measured by flow meter 82 with those other parameters, since all are measured at the same time and thus under the same well conditions. As will be described in further detail below, the system and method according to this embodiment of the invention assists in the planning and scheduling of flow tests for individual wells 4 in the production field, and also analyzes the measurement data as received during a flow test to determine the stability and sufficiency of the flow test data acquired.

[0140] As known in the art, certain wells in a production field may be used as injection wells, by way of which a fluid (*e.g.*, water) can be injected into the reservoir to enhance the production of oil from the producing wells. The flow rate of fluid into injecting wells is similarly dependent on reservoir pressure and other parameters, and as such flow tests of injecting wells are also useful tools. It is contemplated that this invention is similarly applicable when used in connection with flow tests of such injecting wells. As such, to the extent that the description of this embodiment of the invention refers to the flow test of a producing well, it is to be understood that the system and method of this embodiment of the invention can be similarly applied to injecting wells.

[0141] Referring now to Figure 15, the operation of servers 8 of Figure 5 in carrying out well flow tests, according to this embodiment of the invention, will now be described. As described above, it is contemplated that the operations of Figure 15 and related operations described herein are carried out by the execution of computer programs

by the central processing units and other programmable logic in the various computing resources shown in the example of Figure 4, using the software architecture described above in connection with Figures 5 and 6. More specifically, the following description refers to operations carried out by servers 8a and 8b in the architecture of Figures 4 through 6; it is to be understood that other computers may alternatively perform these operations, in some cases including client systems rather than one of servers 8. It is further contemplated that the computer programs executed by these computer resources can be readily created by those skilled in the art having reference to this specification, from the functional descriptions provided in this specification, using conventional programming skill and technique in combination with existing software packages as appropriate, and without undue experimentation. And it is further contemplated that those computer programs will be resident in program memory accessible to those central processing units and other programmable logic, or are otherwise made available to these computer resources, by way of computer-readable media, or otherwise stored in program memory or other conventional optical, magnetic, or other storage resources at those computer resources, or communicated thereto by way of an electromagnetic carrier signal upon which functional descriptive material corresponding to these computer programs is encoded. In addition, it is contemplated that the location at which one or more of these computer programs is resident may be different from the computer resource executing that computer program, such as in the case of the so-called "web-based" application programs. It is also contemplated that those skilled readers can vary this operation from that described in this specification without departing from the scope of the invention as claimed. Accordingly, this operation of the monitoring system according to this embodiment of the invention is described by way of example only.

[0142] As shown in Figure 15, this operation begins with process 90, in which the routing of output from one or more of wells 4 to flow meter 82 (Figure 14) is detected by server 8a. As noted above, it is contemplated that the various valves 84, 86 are monitored or themselves send signals indicating a change in the routing by those valves and others, along with sufficient information to identify which wells 4 are then being metered by flow meter 82, and whether the measured flow is commingled or from a

single well 4. Typically, the metering and routing system in the production field is much more complex and complicated than that illustrated in Figure 14. The flow logic required of flow test monitor module 85 resident at and executed by server 8a should thus have the capability to detect and identify the well 4 that is newly routed to flow meter 82 based on the nature of the information provided from the field.

[0143] Alternatively, the operation of the monitoring system according to this embodiment of the invention may be initiated manually, for example by a human user actuating a display window button at remote access terminal RA, in which case the monitoring system would begin this operation in the same manner as if it had itself detected the routing in process 90.

[0144] As indicated above, it is contemplated that more than one well may be routed to flow meter 82 by way of valves 84, 86. If so, the flow passing through and measured by flow meter 82 will represent the commingled flow from multiple wells. Flow test monitor module 85, according to this embodiment of the invention, is capable of detecting which wells 4 are participating in this commingled measured flow and, for purposes of carrying out a flow test for a specific individual well 4_k, can subtract fluid flow values corresponding to the most recent previous flow measurement results for the wells 4 other than the particular well 4_k of interest in this flow test. As such, for purposes of the following description, references to a particular selected well 4 for which the flow test is being carried out should be understood to refer to the situation in which the flow from a single selected well 4 is routed to flow meter 82, or alternatively the situation in which the actual measured flow is a commingled flow from which recent previous flow results for wells 4 other than the selected well 4_k of interest are subtracted.

[0145] In process 92, according to this embodiment of the invention, signals are forwarded from flow meter 82 to server 8a, via such intermediate data acquisition systems and the like, such signals indicating the flow rate (and phase, if flow meter 82 is a multi-phase flow meter) of fluids measured by flow meter 82 for the output of the selected well 4. In addition, signals are also received by server 8a corresponding to real-time or near-real-time measurements of the conditions at well 4 itself, such measurements

including some or all of downhole and surface temperature, downhole and surface pressure, control valve positions, and the like. In response to these flow test measurements from flow meter 82 and well 4, flow test monitor module 85 measures the stability of the production from well 4, according to statistical or other criteria previously defined by the user. It is contemplated that temperature, pressure, and flow rate information will generally be sufficient to arrive at a determination of the stability of well production, illustrated by decision 93 in Figure 15. As known in the art, a primary purpose of the flow test is to analyze the flow rate of the output of the well relative to downhole and reservoir conditions (temperature, pressure, etc.), enabling a determination of the "productivity" of the well (flow rate delivered for a given pressure difference) and "skin" at the well (*i.e.*, friction, reservoir damage, or other issues inhibiting production); as such, it is generally important for these values to be obtained over a period of time in which the production rate is relatively stable. If the stability criteria are not met by the received measurement data over a specified time duration (decision 93 is "no"), process 92 continues, collecting additional measurement data over time. Upon flow test monitor module 85 determining that a stable production state has been reached (decision 93 is "yes"), the flow test can actually begin, in process 94.

[0146] In process 94, flow test monitor module 85 first identifies a point in time following the stability determination of decision 93 at which the relevant test period begins. Following that start time, flow test monitor module 85 gathers the flow measurements from flow meter 82, and also gathers measurements of the state and condition at well 4, in process 94. Flow test monitor module 85 continues to gather the flow test measurement data in process 94, and executes process 96 to determine the sufficiency of these data relative to a pre-defined criterion. In this embodiment of the invention, this sufficiency determination of process 96 can be carried out in various ways. Process 96 may simply determine the duration of the flow test, or more specifically the time elapsed following decision 93 indicating that the received measurement data are stable; in this case, process 96 determines that sufficient data have been acquired upon this elapsed time or duration reaching a pre-defined limit.

[0147] However, as known in the art, loss of production can be incurred during a flow test, for example if one or more wells 4 are closed in order to isolate the flow from a specific well 4_k of interest for the flow test. As such, it is desirable to minimize the duration of this production loss, by stopping the flow test as soon as sufficient data have been acquired. According to this embodiment of the invention, therefore, process 96 may be performed by flow test monitor module 85 at server 8a, or some other computing resource and software module, statistically analyzing the received flow test measurement data, and determining whether sufficient measurement data have been received to derive a result having an accuracy within some pre-defined level of confidence. For example, the accuracy criterion may determine whether one or more parameters such as an average fluid flow, downhole pressure, reservoir pressure, or the like can be calculated, from the received flow measurement data, that can be considered as accurate to within a desired confidence level. In a specific example of an embodiment of this invention, an equivalent daily flow rate for each phase is periodically calculated from the raw flow measurement data; the period may be user-configured, and can vary from a few minutes to several hours. In this case, the accuracy criterion can deem that sufficient measurement data have been acquired once the statistical error on the mean equivalent daily flow rate falls below a pre-selected limit (*e.g.*, upon the error falling below 100 barrels/day). Those wells that flow at a stable rate would, of course, reach this accuracy criterion sooner (*i.e.*, after fewer calculation periods) than would wells that exhibit a wide range of variability over the measurement time. In any event, this statistical analyzing of the received data determines whether additional data will improve the accuracy of the result to any (statistically) meaningful extent, and does so in a statistical manner that ensures a comparable degree of uncertainty over all wells in the field. It is contemplated that those skilled in the art, having reference to this specification, can identify and implement the appropriate statistical criteria and decision algorithm for process 96 appropriate for specific applications, without undue experimentation. This statistical sufficiency determination, in process 96, thus provides the additional benefit of minimizing the effect of lost production resulting from a flow test of one or more wells 4.

[0148] Upon determining that sufficient data have been acquired, process 96 issues an alert to the responsible individuals (*e.g.*, by email, an indicator via remote access terminal RA, or otherwise) that the flow test can be stopped at any time, or a different well routed to flow meter 82, etc. Meanwhile, in process 96, flow test monitor module 85 continues to receive and process the flow test data until either a specified duration elapses (*e.g.*, on the order of four to six hours) or until the routing or production rate of selected well 4 changes (*e.g.*, in response to the alert that sufficient data have been acquired), at which point the flow test ends.

[0149] It is also contemplated, in connection with this invention, that the operation of flow test management according to this embodiment of the invention may be used to analyze and manage a "multi-rate" flow test for a particular well 4. Such a multi-rate flow test corresponds to a flow test in which the conditions at well 4 under test are changed under the control of the production engineer or other human user, as part of the flow test. This style of flow test thus provides visibility into the transient response of the well, and also into the dependence of measured flow, temperature, pressure and other parameters relative to one another. This embodiment of the invention is capable of acquiring and managing measurement data for such multi-rate flow testing, so long as process 96 is aware that flow measurement data are to be acquired under different or changing conditions; otherwise, as mentioned above, flow test monitor module 85 may stop the flow test and the acquisition of measurement data upon detecting an apparent loss of stability caused by the change in conditions. It is therefore contemplated that the human user would declare the intent to perform such a multi-rate test (and also perhaps the number of test conditions) in advance, prior to the initiation of the flow test in process 90, and that process 96 then operates to not terminate the flow test interval upon detecting a change in well operating conditions (or only after completion of the number or sequence of test conditions specified by the user in advance of the test).

[0150] Regardless of the particular termination criterion or other terminating event, process 96 is completed by flow test monitor module producing a summary or other report, and notifying one or more designated users of the completion of the flow test and the results of that test, in process 100. It is contemplated that these users can be

alerted by way of an automated email, text message, or other automated message transmitted by server 8a, such an alert suggesting that the user access the just-completed flow test results via web browser 25 in the manner described above relative to Figure 5. The message can, if desired, include a link by way of which the user can readily access the results by way of web browser 25. Various other approaches to notifying the appropriate user can alternatively or additionally be used, such approaches including, for example, a visual, audible, or vibrational signal sent to a pager, mobile phone, or other electronic device, or even an automated phone call. In embodiments of this invention, the manner in which the notification or alert is issued can be user-configured, or configured by system or operational management. As evident from this description, it is not necessary for the reservoir engineer or other user to be involved in the performing of the flow test or the processing of data from the flow test up to this point, at which all flow test measurement data have been already acquired, processed, and summarized in an automated manner. Following the alert and communication of process 100, flow test monitor module 85 awaits "validation" of the communicated flow test results by the alerted user. Upon receiving such validation that the just-completed flow test is a valid test, and that its results may be used in further analysis, flow test monitor module 85 stores the measurement data and analysis for that flow test in memory via data historians 20 (Figure 5), in process 101.

[0151] It is contemplated, according to this embodiment of the invention, that storage process 101, as well as other alerts and communications to the users or other personnel, can present the flow test results in various ways. For example, an alert can indicate, to the user at remote access terminal RA, that a tabular report is available for viewing via web browser 25. An example of such a tabular report is illustrated by browser window 115 shown in Figure 16. In this example, information regarding the well 4 that was tested is illustrated by sub-window "General Production Test Information" of browser window 115 (*e.g.*, including identification of the field, the tested well 4, and the separator and other equipment used in the test; the start and stop times, and duration, of the flow test, as well as the time at which sufficient data had been acquired). The sub-window "Results" of browser window 115 of Figure 16, in this

example, presents the measurements obtained from the flow test, and also the results from any applicable predictive well model 27 to which those measurements were applied (*e.g.*, reservoir pressure, etc.), as will be described below. Of course, other or additional approaches to present these results can also be provided by data historians 20 or other functions in server 8a, such approaches including graphic historic IPR (Inflow Performance Relationship) comparisons of tested wells 4 individually and with other wells in the vicinity or production field; historic decline analysis applying recent flow test results in a normalized fashion with historic results; real time versus last flow test nodal comparison trends; and various user-definable or interactive reports, graphs, trends, and the like.

[0152] This operation of this embodiment of the invention as described above, in processing the results of flow tests, provide important benefits in the management of the production field. As described above, this embodiment of the invention manages the acquisition, processing, and summarizing of flow test measurement data without requiring intervention from a human user. Rather, the human user is alerted of the flow test at the appropriate time, at which time he or she can validate the results as appropriate. This maximizes the efficiency with which skilled personnel are utilized, and eliminates the tedious effort and also the subjective variations in human processing of the flow test measurements. As such, flow test monitor 85 and flow test module 80, and the functions thereof described in this specification, can be implemented and provide benefit as stand alone functions, in the absence of the rate and phase functionality described here. However, when combined with the rate and phase functions and modules, the information and results from the flow tests, as acquired and processed by this embodiment of the invention, can be used to even greater advantage, by calibrating and rationalizing the results of the rate and phase calculations by way of the predictive well models.

[0153] Therefore, also in response to the user indication that the flow test results are valid, calibration process 34 can next analyze and calibrate, if necessary, existing predictive well test models 27, based on the results of the completed flow test. In the software architecture of Figure 5, it is contemplated that calibration process 34 will be carried out primarily by flow test module 80 in server 8b, upon request and scheduling

via calculation scheduler 24, and communication of the recently received and processed flow test measurement data via the appropriate web services 23. As such, calibration process 35 can be performed in a non-real-time manner, if desired.

[0154] As shown in Figure 15, calibration process 34 begins with process 98, in which flow test module 80 evaluates the flow test results using one or more current predictive models 27 for the corresponding well 4. It is contemplated that process 98 can be executed in various ways. For example, the downhole and surface temperature and pressure measurements acquired from well 4 during the flow test can be applied to the well model or models 27 to estimate a flow rate; that estimated flow rate can then be compared against the flow rate actually measured by flow meter 82 during the flow test, thus determining the accuracy of the well models 27 relative to actual measurements. Alternatively, the measured flow rate can be applied to the models 27 to produce estimates of the other well measurements that are then compared to the actual measurements, in process 98. In any event, flow test module 80 evaluates decision 99 to determine if the flow test measurements match the selected predictive well models 27 within a pre-determined tolerance . If so (decision 99 is "yes"), the current well models 27 are sufficiently accurate, and may continue to be used in the manner described above for calculation process 35 (Figure 7).

[0155] If the just-completed flow test results for well 4 do not adequately match the existing predictive well models 27 (decision 99 is "no"), calibration process 34 performed by flow test module 80 next calibrates or adjusts the predictive rate and phase models 27, in process 102. As described above, the various well models 27 calculate values, such as rate and phase, using previously determined relationships of other measurements (downhole and surface pressures and temperatures, for example) to the output parameters of rate and phase. In process 102, the constants and functions of those parameters used in those models can be adjusted to reflect the relationship as currently measured in practice by the flow test. Alternatively, a calibration factor may be applied to the existing model to adjust the model output result to match the measured flow rate, rather than changing the constants and functions within the model itself, if desired. In either case, the calibrated or adjusted model or models 27 produced in process 102 are

forwarded to the designated responsible user for validation. If the user does not validate the adjustment or calibration (decision 103 is "no"), process 102 can be repeated to attempt a different calibration or adjustment, perhaps in an interactive way with the user. Upon the user validating the calibration or adjustment to the model or models 27 (decision 103 is "yes), calculation process 35 using the updated models 27 can begin.

[0156] Process 35 applies the updated well model or models 27 in the manner described above, using real-time or near-real-time well measurements obtained from the well 4 of interest, along with the other wells 4 in the production field being monitored by the system. According to this embodiment of the invention, however, flow test module 80 also assists in the planning and scheduling of subsequent flow tests, as will now be described. In normal operation, upon completion of one or more instances of calculation process 35, flow test module 80 determines whether the model output rate and phase values are within a certain acceptable range R. This range R is previously set by the engineering staff or other users, in process 104, and is communicated to and stored at server 8b. It is contemplated that this range R corresponds to a range of rate and phase values that does not indicate the usefulness of a special (*i.e.*, out of schedule) flow test for the concerned well 4. If the results of calculation process 35 are within the expected or tolerable range R (decision 105 is "yes"), then the calculated rate and phase values are communicated to data historians 20 for storage in the usual manner, in process 108, as described above. It is contemplated that storage process 108 will include, for each set of flow test results, such information as identification of well 4 to which the flow test applies, the measured flow rate or rates over the flow test time period, a time stamp indicating the date and time of the flow test, and data corresponding to the other measurements such as downhole and surface pressure and temperatures obtained during the flow test. Other or different data, information, and measurements may be stored in storage process 108, as determined by the engineering staff or other users. In addition, the results of the flow test, and of the applicable predictive well model 27 to which the flow test measurements were applied, can be presented in process 108, for example in the manner described above relative to browser window 115 of Figure 16. Referring back to Figure 15, if the rate and phase results from the applicable well models 27 do not fall

within the expected or tolerable range R (decision 105 is "no"), flow test module 80 issues an alert to the responsible designated users in process 110. This alert, as noted above, indicates that the predictive well models 27 have returned rate and phase information, based on recent measurements, that indicate the need for a special flow test to be performed on a particular well. Upon detecting that the staff has rerouted the well 4 output to flow meter 82 again (process 90), in response to the alert issued in process 110 or otherwise, the performing of a flow test and the resulting calibration process 34 and calculation process 35 of Figure 15 commences again.

[0157] According to another aspect of this embodiment of the invention, flow test module 80 residing at server 8b defines and maintains a schedule of flow tests for the wells 4 in the production field, and issues alerts or reminders to the designated staff to carry out flow tests on specific wells according to such a schedule. Various parameters and attributes may be used by flow test module 80 to perform this function. One such parameter is a "maximum legal days" limit, pre-defined by the engineering staff or other users and stored at server 8b, in this example; such a limit ensures that, even if no other parameter or indicator causes a flow test to be initiated for a given well 4, a flow test will be performed for that well 4 within that specified frequency. Other parameters that can be used to define the priority and schedule of flow tests for a given well 4 (and applied to each of wells 4 in the field) include: the percentage of the total field contribution provided by well 4; recent trend direction and magnitude over time for well 4; differences in measured and estimated downhole pressures, or differences between rate and phase as actually measured and those estimated by the best model 27; days elapsed since the most recent flow test for well 4; and the like. These parameter values, and others that can be used in such prioritization, are updated in response to the most recent flow tests and also to recent pressure and temperature measurements, and predictive model 27 output, for the various wells 4 in the production field. According to this aspect of this embodiment of the invention, flow test module 80 has access to the applicable ones of these and other parameters for each well 4, applies these values to a prioritization algorithm or equation defining the flow test schedule, and derives a schedule for flow tests for wells 4 in the production field based on the results of that prioritization. It is contemplated that those

skilled in the art having reference to this specification will be readily able to derive such a prioritization algorithm or equation, as applicable to the particular production field situation faced by those skilled persons, without undue experimentation. Upon the prioritization algorithm or equation results indicating that a particular well 4 is due for a flow test, server 8b or some other resource in the system can issue an alert or reminder to the appropriate personnel so that the flow test can be carried out; alternatively, these personnel may anticipate and follow an overall flow test schedule established for the production field by flow test module 80. In either case, according to the operation of this embodiment of the invention as described above, the initiation of a flow test for a given well 4 is automatically detected (process 90 of Figure 15), with the results updated and applied as described above in an automated manner, with no further real-time involvement required of human personnel to attain the flow test results.

[0158] The calculated rate and phase values from calculation process 35, according to embodiments of this invention, may then be adjusted using one or more reconciliation factors or equations, in reconciliation process 40. This process 40 uses the production rate and phase determined for multiple wells W that share export facilities, determined according to the embodiments described above, and reconciles those rate and phase calculations against data and measurements from those export facilities. In such reconciliation, periodic export data is compared to the sum total production for the same period from each well feeding into the export facility. Any difference between the totals can be used to create a reconciliation factor, which may be in the form of a function or, if sufficiently stable, a constant. In those cases where the export facilities data is more reliable than the well data, the reconciliation factor is applied to each well W sharing that export facility. For example, the production information from each such well W may be adjusted pro-rata to reconcile the totals. Alternatively, if data from one or more wells W_k is considered less reliable than other wells W sharing that export facility, production data from those less reliable wells W_k may be reconciled to a greater degree than data from the more reliable wells W. This methodology applies equally to oil water and gas from production wells and to injection water or injection gas distributed to well via common compression systems.

[0159] In other cases, the rate and phase calculations from wells W may be considered more reliable than data from export facilities. In such other cases, the export facility data may be reconciled using the well data and the export facility data may be adjusted.

[0160] Reconciliation process 40 thus also allows better determination of anomalous results from individual wells. For example, reconciliation process 40 may reveal a sudden increase in the discrepancy between well data and export facility data. Further investigation may reveal that a particular well experienced changed conditions during that time period or that a particular well experienced an unexpected deviation in calculated rate and phase values. In either case, reconciliation process 40 can help identify such issues that requiring further attention. Conversely, this reconciliation may also reveal faults in export facilities equipment.

[0161] With further reference to Figure 7, the reconciled data produced by reconciliation process 40 can then be used in additional ways. For example, the reconciled rate and phase values from process 40 can be used to determine whether any alerts or actions should be triggered, in alert process 38. Typically, the reconciled results are analyzed by process 38 in relation to predetermined parameters. For example, if the reconciled results are outside a predetermined range, an alert or other action may be triggered. Such analysis may involve a series of reconciled results which may be analyzed to identify a pattern or trend and may trigger an alert. Because continuous and near real time data is used, the information can be analyzed in alert process 38 for correlations which may be used to set future alert parameters. For example, when an event occurs, the data can be reviewed by an operator, via web browser application 25 (Figure 5) for example, to determine whether a particular trend or pattern can be identified which may correlate to the particular event. If identified, the pattern or trend can be used to set new or updated alert parameters for the particular event, for future instances of alert process 38.

[0162] For example, wells typically experience periodic shut-ins – either planned or unplanned. These shut-in events are useful, in that reservoir pressure determined

during a shut-in can be input into a predictive well model 27, and current sensor measurement data then applied to that model to determine the average reservoir pressure and skin for that well W. Positive skin is a measure of the additional pressure experienced near well bore over and above that required to flow the fluids through rock of a known permeability (skin increases progressively as rock near a well becomes damaged due to scale or solids deposition) while negative skin is the reduction in the expected pressure drop needed to flow the fluids through the rock at the near well bore which may occur, for example, due to artificial stimulation and fracturing of the rock or the natural onset of sand production with flow. Frequent skin value determinations allow operators to better anticipate changes in reservoir performance and more effectively take corrective action if problems are observed. This calculation of reservoir pressure and skin factor for a newly shut-in well W can be carried out by an operator in response to an alert issued by alert process 38.

[0163] As illustrated in Figure 7, these data may be applied to hydrocarbon allocation process 44 to apportion the actual produced fluid volumes between the wells and the reservoir zones from which they produce, for regulatory reporting and financial accounting purposes. In addition, these reconciled data may be applied to reservoir simulation process 42, to produce or update a simulation or a model for the entire reservoir. For these and other purposes, the calculated rate and phase data may be averaged over a period of time, or alternatively may be applied in "raw" form, without averaging, filtering, or other mathematical manipulations.

[0164] A reality in modern production fields is that activity in a particular well may impact other wells. For example, a production increase in one well may decrease or otherwise impact production in other wells. In another example, water injection designed to improve production of a well may also have an impact on other wells in the field. According to conventional techniques, this inter-relation among wells is not fully appreciated or utilized in reservoir maintenance, because of the lack of real-time continuous data.

[0165] According to this embodiment of the invention, as illustrated in Figure 7, predictive well models 27 are applied, in instances of calculation process 35, to measurements from multiple wells W in the same production field. The results of these multiple instances of calculation process 35 are correlated with one another, in process 45. This correlation process 45 may be performed by calculation scheduler module 24 either on a periodic basis, or on demand based on a request from an operator via remote access terminal RA. Correlation process 45 is contemplated to include conventional statistical correlation of rate, phase, and other parameters over multiple wells W, using the associated time-base or time-stamps on those results to align the results among the various wells. For example, correlation of the rate and phase results from multiple wells in a field in process 45 may allow the operator to identify a correlation between a particular activity in one well and a corresponding impact on another well. Such correlation is not readily available in conventional systems using empirical models, or using less frequent calculations. On the other hand, by employing the methods in accordance with this invention, operators are better able to optimize production and improve reservoir management.

[0166] In other cases, use of predictive models in accordance with this invention on multiple wells W in a field or reservoir can help identify anomalous well performance. For example, in the event that rate and phase determination reveals a change in production from a particular well in a certain field, the operator may expect to observe certain changes in performance of other wells. If correlation process 45 indicates that those expected changes in the performance of other wells did not occur, or occurred to a substantially lesser extent than expected, the operator could then carry out closer investigation, to determine whether the unexpected change (or lack of change) is due to a fault in the sensors or other equipment at one of the wells, or an unexpected characteristic of the reservoir formation. The frequent calculations resulting from embodiments of this invention permit a better understanding of inter-relation of well performance, and thus enable operators to more readily adjust the operation of each well to obtain optimum overall performance.

[0167] The predictive models and other equations in accordance with this invention are preferably employed in computing facilities located remotely from the well and may even be remote from the field. For example, sensor data may be transmitted to a regional or central location when rate and phase calculations are performed. Each rate and phase value calculated is preferably stored and made available for display in both numerical and graphical format by users. Such users may in turn be located in locations remote from the regional or central location. For example, such users may be operators on a platform or may be engineering personnel or other users in other locations.

[0168] The method, system, and computer software according to embodiments of the invention provide important advantages and benefits in the operation of a hydrocarbon production field. Because data and information are continuously provided in near-real-time, according to embodiments of the invention, correlations and trends in the production from individual wells, and over the entire production field and reservoir, can be more easily observed, and more timely observed. In addition, because of the automated nature of the monitoring system according to embodiments of the invention, the operator can receive alerts of changes in conditions, or upon certain occurrences in the field. This allows operators to take corrective or other action with better response time than systems which do not provide real time continuous information. In addition, the human operators are not burdened with sifting through the massive amount of measurement data generated from modern transducers, operating at data acquisition frequencies of has high as one per second per transducer. The near-real-time calculations provided by this system are particularly useful in detecting and being alerted to the onset of well flow instability, slugging, and the like, and to the effect that such conditions have on wells flowing into common flowlines.

[0169] In addition, as described above, according to embodiments of the invention, current measurements from a well can be applied to more than one well model, with a hierarchy of models derived according to a measure of the reliability of the measurements from various sensors, the accuracy of the monitoring system is greatly improved over conventional single-model snapshot methods. The monitoring system according to this invention is also able to manage these multiple well models, on near-

real-time measurement data, in an automated manner, thus freeing human operations staff from dealing with a high volume of data in order to manage the production field. In short, the methods and system according to embodiments of the invention provide more accurate results, in a more timely manner, with less human intervention required, as compared with conventional monitoring approaches in the industry, and more robustly from the standpoint of sensor and transducer accuracy, calibration, and reliability.

[0170] In addition, the results from well models that are not deemed to provide the most reliable rate and phase measurements can still be useful in identify trends or patterns that may correlate to events. Such a pattern or trend may even be identified using results from more than one model to identify a correlation of an event with the combination of results.

[0171] While the present invention has been described according to its embodiments, it is of course contemplated that modifications of, and alternatives to, these embodiments, such modifications and alternatives obtaining the advantages and benefits of this invention, will be apparent to those of ordinary skill in the art having reference to this specification and its drawings. It is contemplated that such modifications and alternatives are within the scope of this invention as subsequently claimed herein.

WHAT IS CLAIMED IS:

1. A method of managing a flow test in which a flow rate of fluid of a well is determined, the method comprising the steps of:

receiving measurement data corresponding to fluid flow output from the well;

operating a computer to identify a flow test time interval over which stable output flow measurements are represented in the received measurement data;

operating a computer to determine an end of the flow test time interval; and

then notifying a user of the completion of a flow test of the well, the flow test corresponding to the received measurement data over the flow test time interval.

2. The method of claim 1, further comprising:

obtaining temperature and pressure measurements from sensors at the well at a time corresponding to the flow test time interval;

operating a computer to apply the temperature and pressure measurements to at least one predictive well model to estimate a fluid rate from those measurements; and

comparing the estimated fluid rate with a measured fluid rate corresponding to the received measurement data during the flow test time interval.

3. The method of claim 2, further comprising:

responsive to the comparing step determining that the estimated fluid rate and measured fluid rate differ from one another beyond a tolerance, modifying the at least one predictive well model by notifying a user of results of the comparing step; and

then modifying the at least one predictive well model responsive to receiving a validation signal.

4. The method of claim 3, further comprising:

then obtaining temperature and pressure measurements from sensors at the well;

operating a computer to apply the temperature and pressure measurements to the modified at least one predictive well model to calculate fluid rate and phase composition values from those measurements.

5. The method of claim 1, further comprising:

storing, in a computer-readable medium, data corresponding to the flow test of the well, the stored data comprising identification of the well to which the flow test pertains, a measured fluid rate corresponding to the received measurement data during the flow test time interval, and a time stamp indicating the date and time of the flow test.

6. The method of claim 1, further comprising:

repeating the receiving, operating, and notifying steps for a plurality of wells in a production field.

7. The method of claim 1, further comprising:

prior to the step of receiving measurement data, receiving, from the production field, a signal indicating that the fluid output from the well has been routed to a flow meter.

8. The method of claim 1, further comprising:

receiving an initiation signal from a remote access terminal, wherein the steps of receiving measurement data and operating the computer are performed responsive to receiving the initiation signal.

9. The method of claim 1, further comprising:

then determining a scheduled time at which a next flow test of the well is to be performed; and

notifying a user of the scheduled time at which the next flow test of the well is to be performed.

10. The method of claim 1, wherein the receiving step comprises:

receiving measurement data corresponding to the commingled fluid flow output of a plurality of wells; and

subtracting fluid flow values for each of the plurality of wells other than a well of interest, from the measurement data corresponding to the commingled fluid flow output, to determine the measurement data corresponding to the fluid flow output from the well of interest.

11. The method of claim 1, wherein the step of operating the computer to determine the end of the flow test time interval comprises:

processing the received measurement data to determine whether the received measurement data meet a stability criterion;

then identifying the end of the flow test time interval responsive to the received measurement data satisfying a sufficiency criterion; and wherein identifying the end of the flow test time interval comprisesstatistically analyzing the received measurement data to determine whether a parameter based on the received measurement data can be derived to within an accuracy range to a predetermined confidence level.

12. The method of claim 1, wherein the step of identifying the end of the flow test time interval comprises:

measuring elapsed time after a point in time at which the received measurement data meet a stability criterion;

identifying the end of the flow test time interval upon the elapsed time meeting a duration criterion.

13. The method of claim 1, wherein the step of operating the computer to determine the end of the flow test time interval comprises:

detecting a change in the operating conditions of the well, wherein responsive to receiving a user input indicating that the flow test is to be performed over a sequence of operating conditions; and

determining the end of the flow test time interval by detecting the change in the operating conditions of the well after completion of the sequence of operating conditions.

14. A computer system, comprising:

a communications interface for receiving measurement data corresponding to fluid flow output from a hydrocarbon well;

one or more central processing units for executing program instructions; and

program memory, coupled to the central processing unit, for storing a computer program including program instructions that, when executed by the one or more central processing units, cause the computer system to perform a plurality of operations for managing a flow test in which a flow rate of fluid produced from the well is determined, the plurality of operations comprising:

identifying a flow test time interval over which stable output flow measurements are represented in the measurement data received over the communications interface;

determining an end of the flow test time interval; and

then issuing a notification of the completion of a flow test of the well, the flow test corresponding to the received measurement data over the flow test time interval.

15. The system of claim 14, wherein the measurement data received over the communications interface further comprises:

measurement data corresponding to temperature and pressure measurements from sensors at the well at a time corresponding to the flow test time interval, and wherein the plurality of operations further comprises:

applying the temperature and pressure measurements to at least one predictive well model to estimate a fluid rate from those measurements;

comparing the estimated fluid rate with a measured fluid rate corresponding to the received measurement data during the flow test time interval; and

responsive to the comparing operation determining that the estimated fluid rate and measured fluid rate differ from one another beyond a tolerance, modifying the at least one predictive well model.

16. The system of claim 15, wherein the plurality of operations further comprises:

applying temperature and pressure measurements obtained from sensors at the well to the modified at least one predictive well model to calculate fluid rate and phase composition values from those measurements.

17. The system of claim 14, further comprising:

a memory resource, coupled to the one or more central processing units, for storing a database;

and wherein the plurality of operations further comprises:

storing, in the memory resource, data corresponding to the flow test of the well, the stored data comprising identification of the well to which the flow test pertains, a measured fluid rate corresponding to the received measurement data during the flow test time interval, and a time stamp indicating the date and time of the flow test.

18. The system of claim 14, wherein the plurality of operations further comprises:

then determining a scheduled time at which a next flow test of the well is to be performed; and

issuing a notification of the scheduled time at which the next flow test of the well is to be performed.

19. The system of claim 14, wherein the measurement data received over the communications interface corresponds to commingled fluid flow output of a plurality of wells;

and wherein the plurality of operations further comprises:

subtracting fluid flow values for each of the plurality of wells other than a well of interest, from the measurement data corresponding to the commingled fluid flow output, to determine the measurement data corresponding to the fluid flow output from the well of interest.

20. The system of claim 14, wherein the operation of determining the end of the flow test time interval comprises:

processing the received measurement data to determine whether the received measurement data meet a stability criterion; and

statistically analyzing the received measurement data to determine whether a sufficiency criterion is satisfied, the sufficiency criterion comprising a determination that a parameter based on the received measurement data can be derived to within an accuracy range to a predetermined confidence level;

responsive to determining that the sufficiency criterion is satisfied, then identifying the end of the flow test time interval.

21. The system of claim 14, wherein the operation of determining the end of the flow test time interval comprises:

measuring elapsed time after a point in time at which the received measurement data meet a stability criterion;

identifying the end of the flow test time interval upon the elapsed time meeting a duration criterion.

22. The system of claim 14, wherein the operation of determining the end of the flow test time interval comprises:

detecting a change in the operating conditions of the well, and

wherein the plurality of operations further comprises:

responsive to receiving a user input indicating that the flow test is to be performed over a sequence of operating conditions, determining the end of the flow test time interval by detecting the change in the operating conditions of the well after completion of the sequence of operating conditions.

23. A computer-readable medium storing a computer program that, when executed on a computer system, causes the computer system to perform a plurality of operations for managing a flow test in which a flow rate of fluid produced from the well is determined, the plurality of operations comprising:

identifying a flow test time interval over which stable output flow measurements are represented in the measurement data received over the communications interface;

determining an end of the flow test time interval; and

then issuing a notification of the completion of a flow test of the well, the flow test corresponding to the received measurement data over the flow test time interval.

24. The computer-readable medium of claim 23, wherein the plurality of operations further comprises:

applying data corresponding to temperature and pressure measurements from sensors at the well at a time corresponding to the flow test time interval to at least one predictive well model to estimate a fluid rate from those measurements;

comparing the estimated fluid rate with a measured fluid rate corresponding to the received measurement data during the flow test time interval; and

responsive to the comparing operation determining that the estimated fluid rate and measured fluid rate differ from one another beyond a tolerance, modifying the at least one predictive well model; and

applying temperature and pressure measurements obtained from sensors at the well to the modified at least one predictive well model to calculate fluid rate and phase composition values from those measurements.

25. The computer-readable medium of claim 23, wherein the plurality of operations further comprises:

then determining a scheduled time at which a next flow test of the well is to be performed; and

issuing a notification of the scheduled time at which the next flow test of the well is to be performed.

26. The computer-readable medium of claim 23, wherein the measurement data corresponds to commingled fluid flow output of a plurality of wells;

and wherein the plurality of operations further comprises:

subtracting fluid flow values for each of the plurality of wells other than a well of interest, from the measurement data corresponding to the commingled fluid flow output, to determine the measurement data corresponding to the fluid flow output from the well of interest.

27. The computer-readable medium of claim 23, wherein the operation of determining the end of the flow test time interval comprises:

processing the received measurement data to determine whether the received measurement data meet a stability criterion; and

statistically analyzing the received measurement data to determine whether a sufficiency criterion is satisfied, the sufficiency criterion comprising a determination that a parameter based on the received measurement data can be derived to within an accuracy range to a predetermined confidence level;

responsive to determining that the sufficiency criterion is satisfied, then identifying the end of the flow test time interval.

28. The computer-readable medium of claim 23, wherein the operation of determining the end of the flow test time interval comprises:

measuring elapsed time after a point in time at which the received measurement data meet a stability criterion;

identifying the end of the flow test time interval upon the elapsed time meeting a duration criterion.

* * * * *

FIG. 1

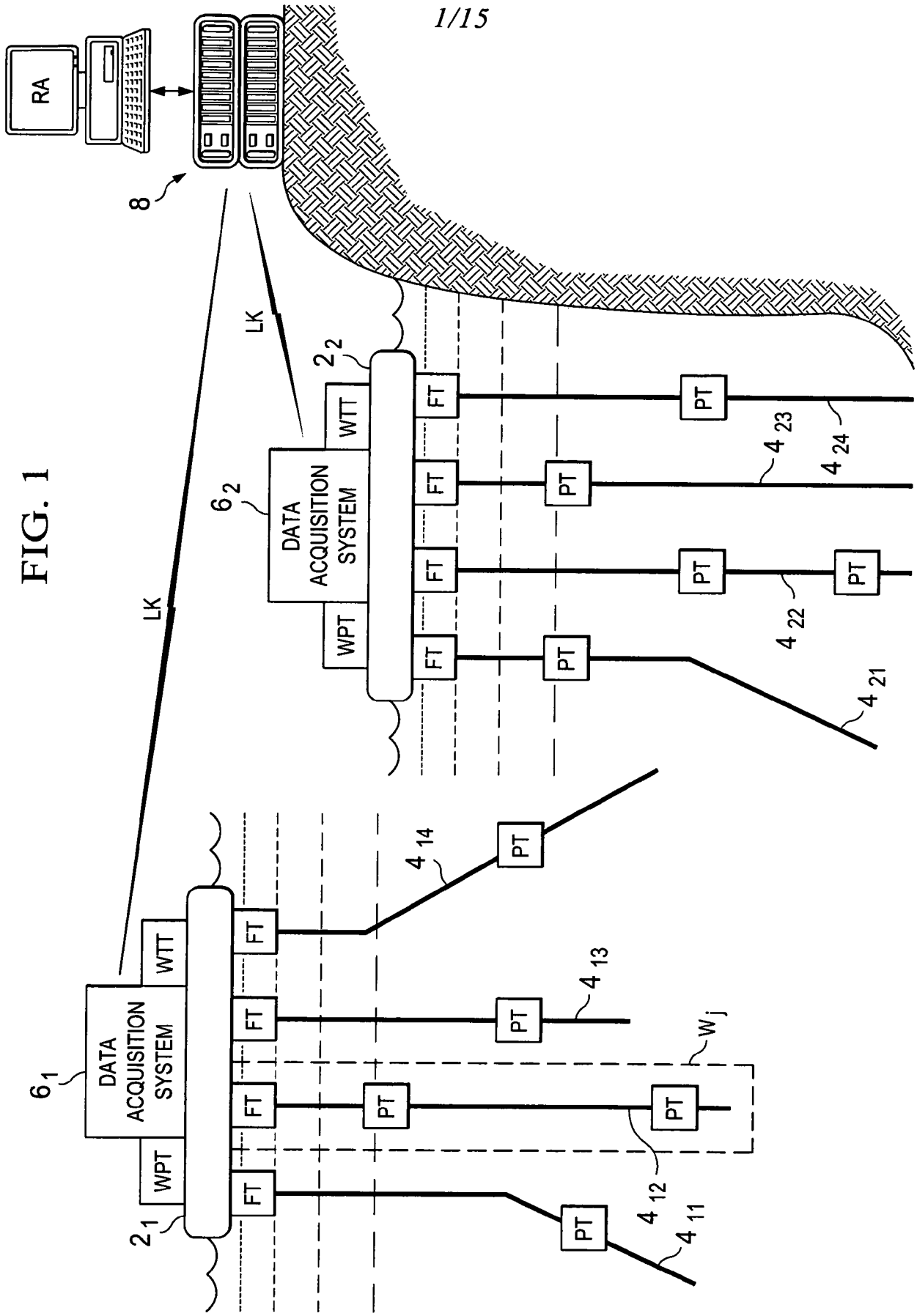

RA
8
LK
LK
2_2
WTT
WPT
FT
PT
DATA ACQUISITION SYSTEM
6_2
4_{23}
4_{24}
4_{22}
4_{21}
6_1
2_1
4_{14}
4_{13}
W_j
4_{12}
4_{11}

FIG. 2

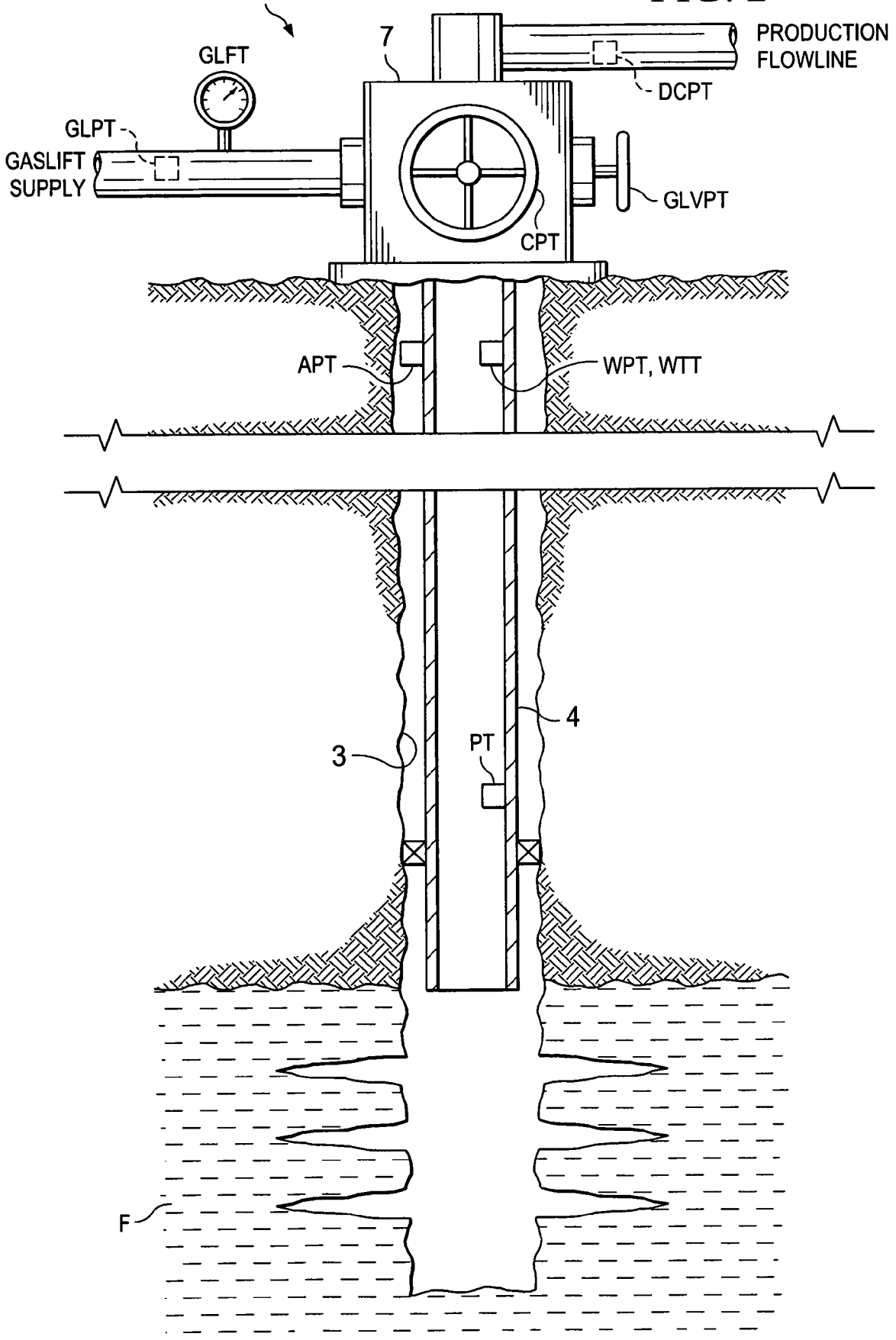

9
7
GLFT
GLPT
GASLIFT
SUPPLY
PRODUCTION
FLOWLINE
DCPT
GLVPT
CPT
APT
WPT, WTT
4
3
PT
F

FIG. 3

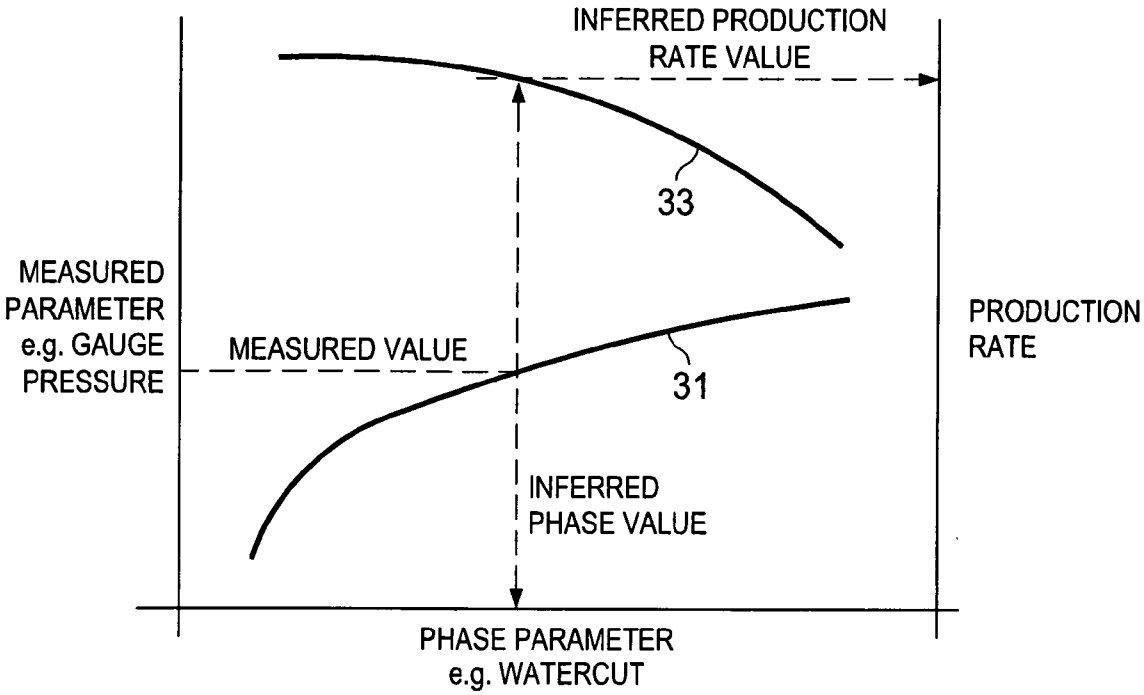

INFERRED PRODUCTION RATE VALUE
33
MEASURED PARAMETER e.g. GAUGE PRESSURE
MEASURED VALUE
31
PRODUCTION RATE
INFERRED PHASE VALUE
PHASE PARAMETER e.g. WATERCUT

FIG. 7

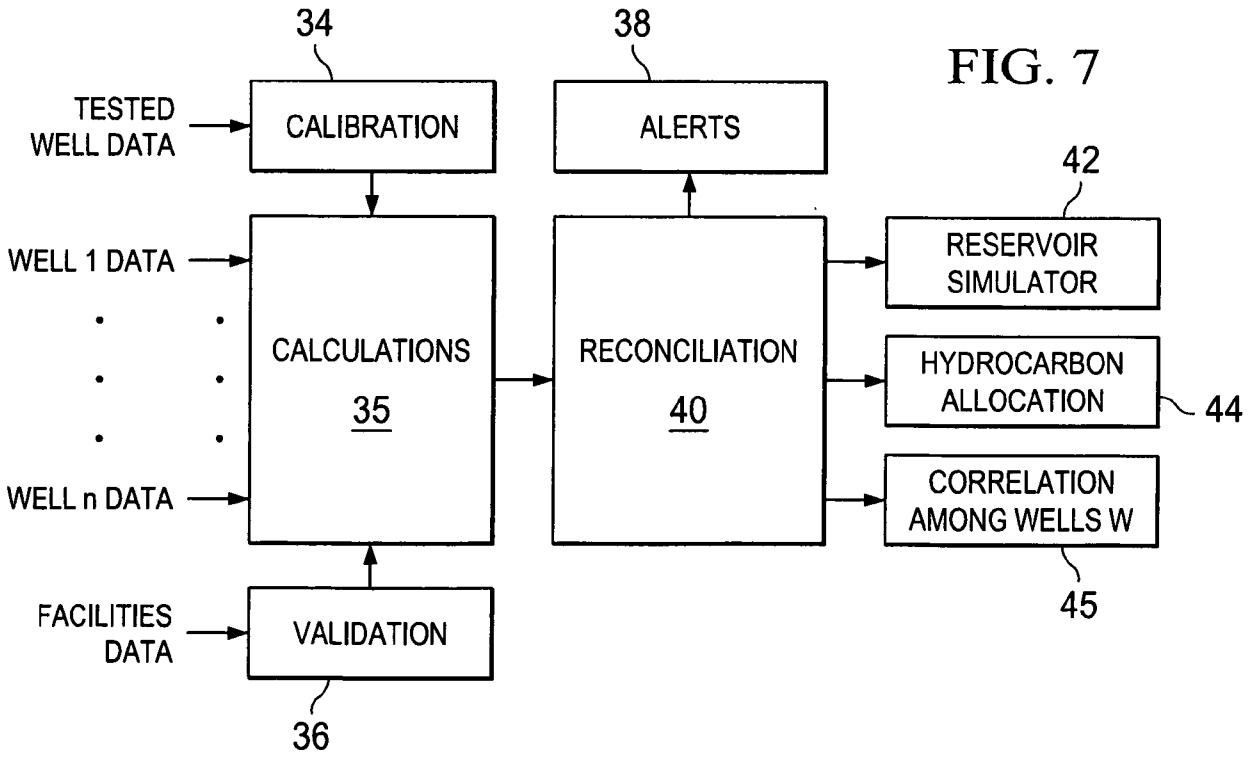

34
38
TESTED WELL DATA
CALIBRATION
ALERTS
42
WELL 1 DATA
RESERVOIR SIMULATOR
CALCULATIONS 35
RECONCILIATION 40
HYDROCARBON ALLOCATION
44
WELL n DATA
CORRELATION AMONG WELLS W
45
FACILITIES DATA
VALIDATION
36

FIG. 4

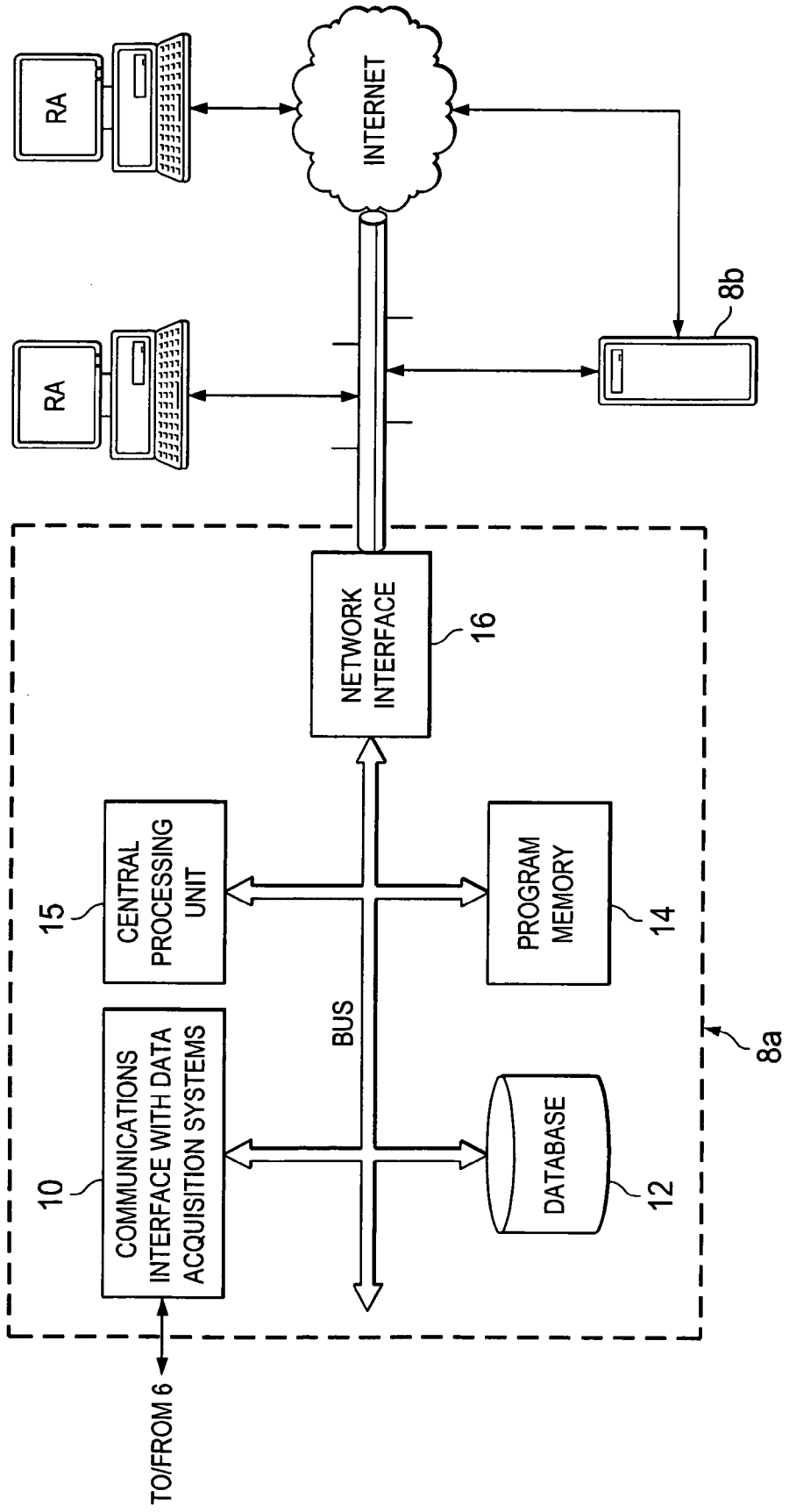

RA
RA
INTERNET
8b
NETWORK INTERFACE
16
CENTRAL PROCESSING UNIT
15
PROGRAM MEMORY
14
BUS
COMMUNICATIONS INTERFACE WITH DATA ACQUISITION SYSTEMS
10
DATABASE
12
8a
TO/FROM 6

FIG. 5

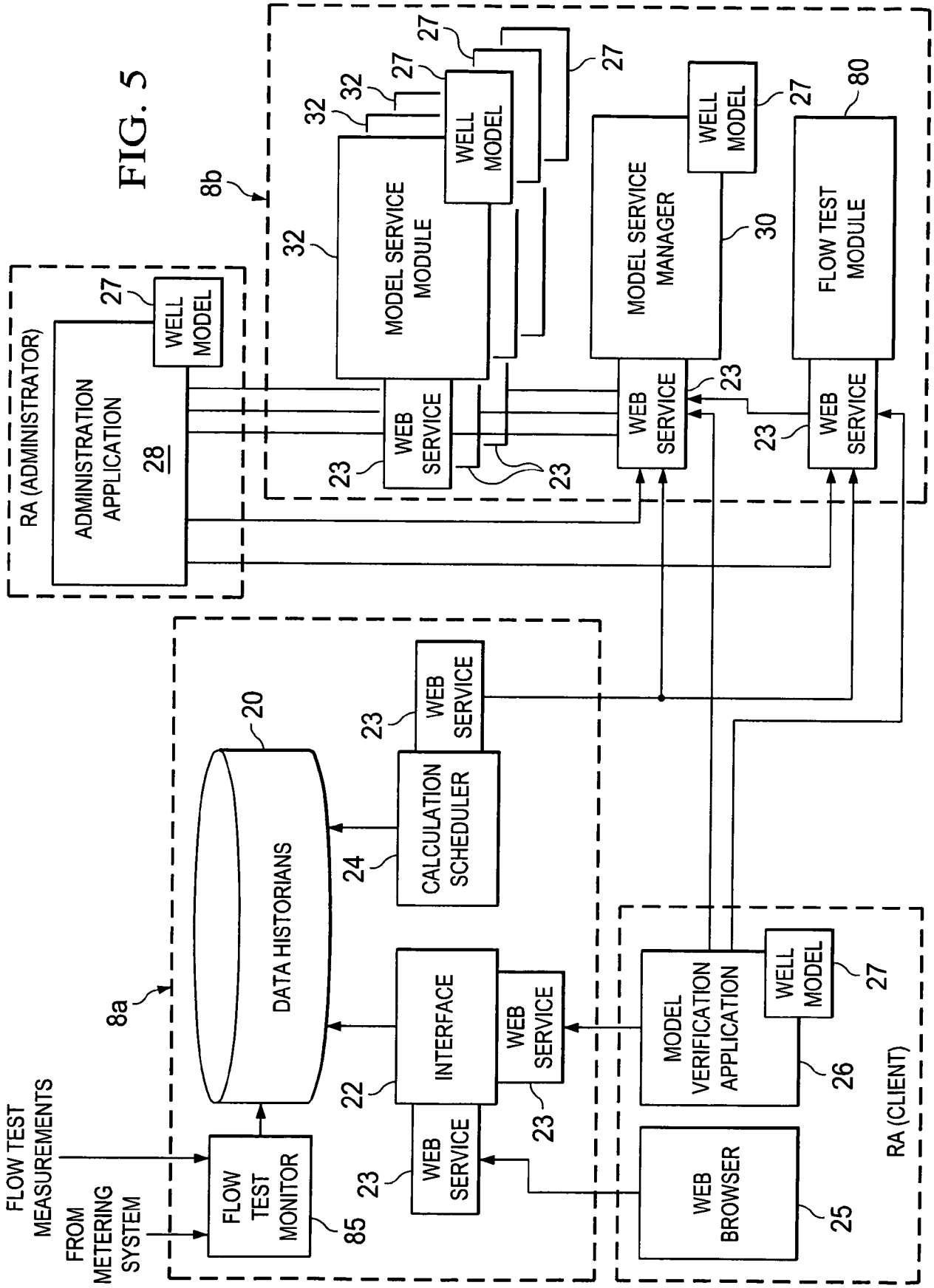

RA (ADMINISTRATOR)
ADMINISTRATION APPLICATION
28
WELL MODEL
27
8b
32
MODEL SERVICE MODULE
WELL MODEL
MODEL SERVICE MANAGER
30
WELL MODEL
FLOW TEST MODULE
80
WEB SERVICE
23
WEB SERVICE
WEB SERVICE
8a
DATA HISTORIANS
20
CALCULATION SCHEDULER
24
WEB SERVICE
INTERFACE
22
WEB SERVICE
WEB SERVICE
FLOW TEST MONITOR
85
FLOW TEST MEASUREMENTS FROM METERING SYSTEM
MODEL VERIFICATION APPLICATION
WELL MODEL
26
WEB BROWSER
25
RA (CLIENT)

FIG. 6

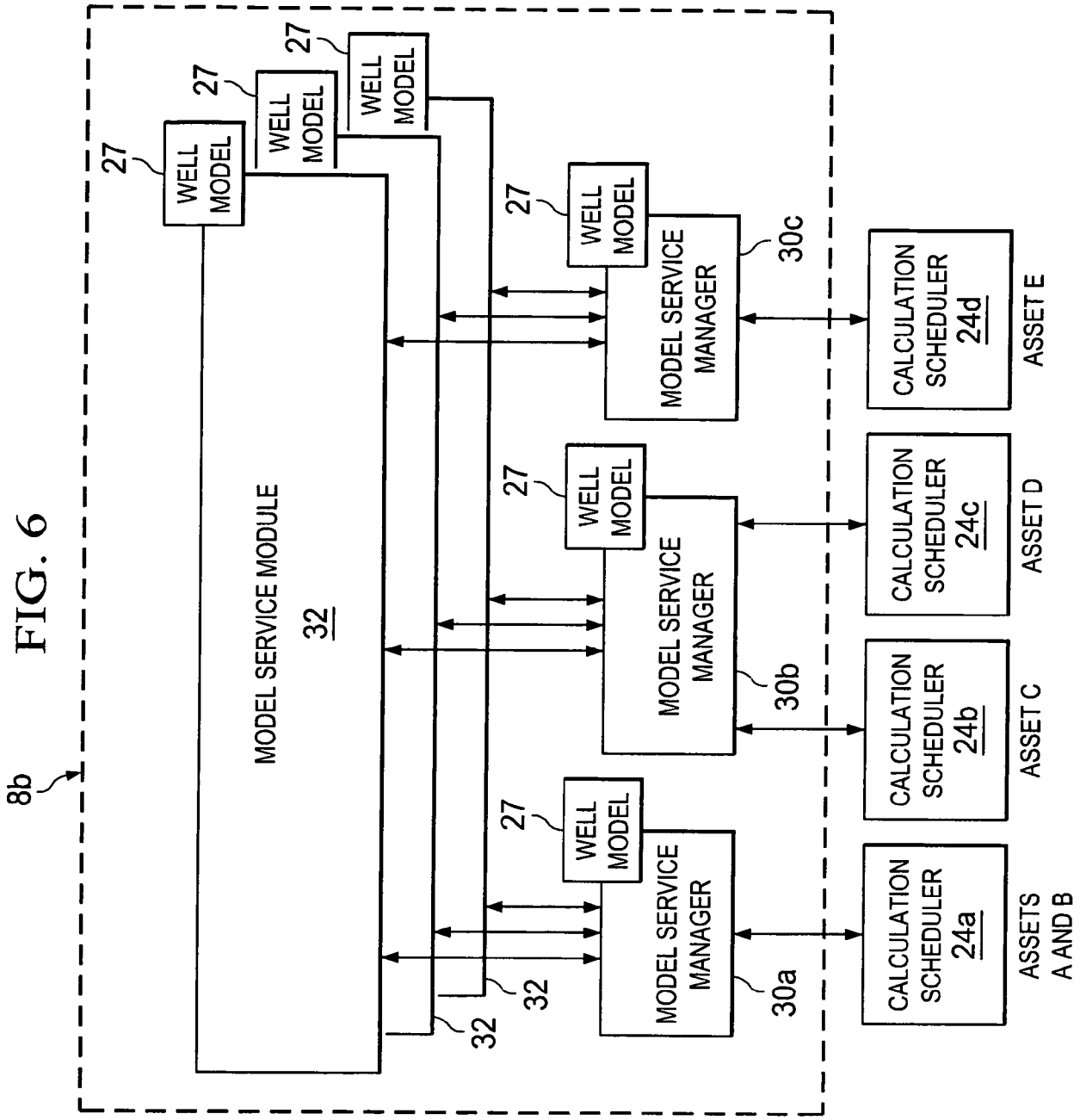
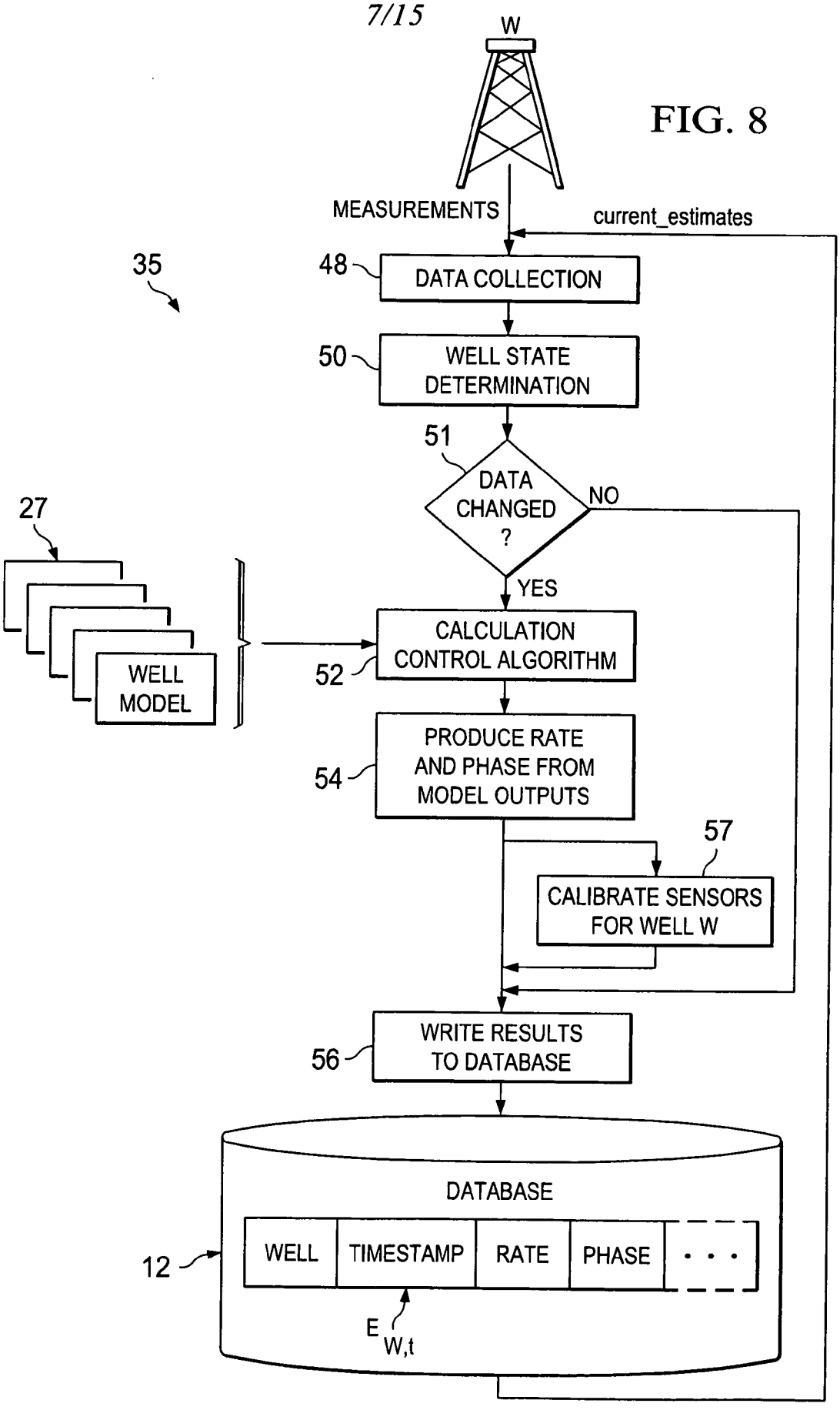

8b
MODEL SERVICE MODULE
32
WELL MODEL
27
MODEL SERVICE MANAGER
30a
30b
30c
CALCULATION SCHEDULER
24a
24b
24c
24d
ASSETS A AND B
ASSET C
ASSET D
ASSET E

FIG. 8


W
MEASUREMENTS
current_estimates
35
48
DATA COLLECTION
50
WELL STATE DETERMINATION
51
DATA CHANGED ?
NO
YES
27
WELL MODEL
52
CALCULATION CONTROL ALGORITHM
54
PRODUCE RATE AND PHASE FROM MODEL OUTPUTS
57
CALIBRATE SENSORS FOR WELL W
56
WRITE RESULTS TO DATABASE
DATABASE
12
WELL
TIMESTAMP
RATE
PHASE
E W,t

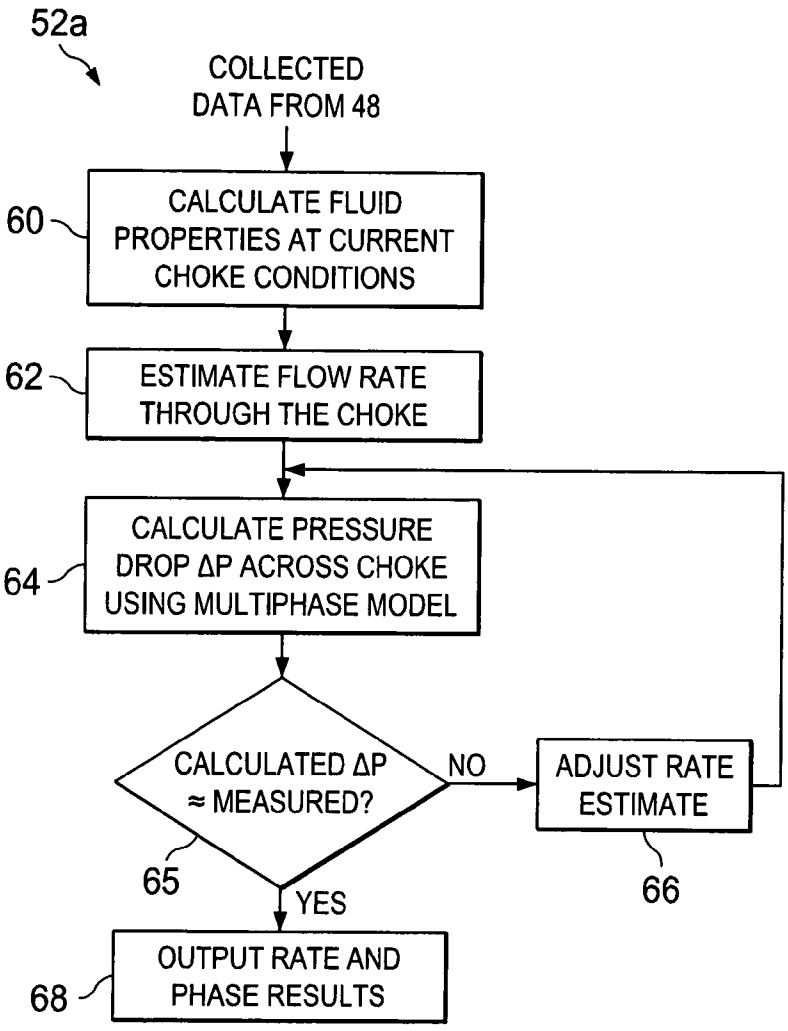

52a
COLLECTED DATA FROM 48
60
CALCULATE FLUID PROPERTIES AT CURRENT CHOKE CONDITIONS
62
ESTIMATE FLOW RATE THROUGH THE CHOKE
64
CALCULATE PRESSURE DROP ΔP ACROSS CHOKE USING MULTIPHASE MODEL
CALCULATED ΔP ≈ MEASURED?
NO
ADJUST RATE ESTIMATE
65
66
YES
68
OUTPUT RATE AND PHASE RESULTS

FIG. 9

FIG. 10a

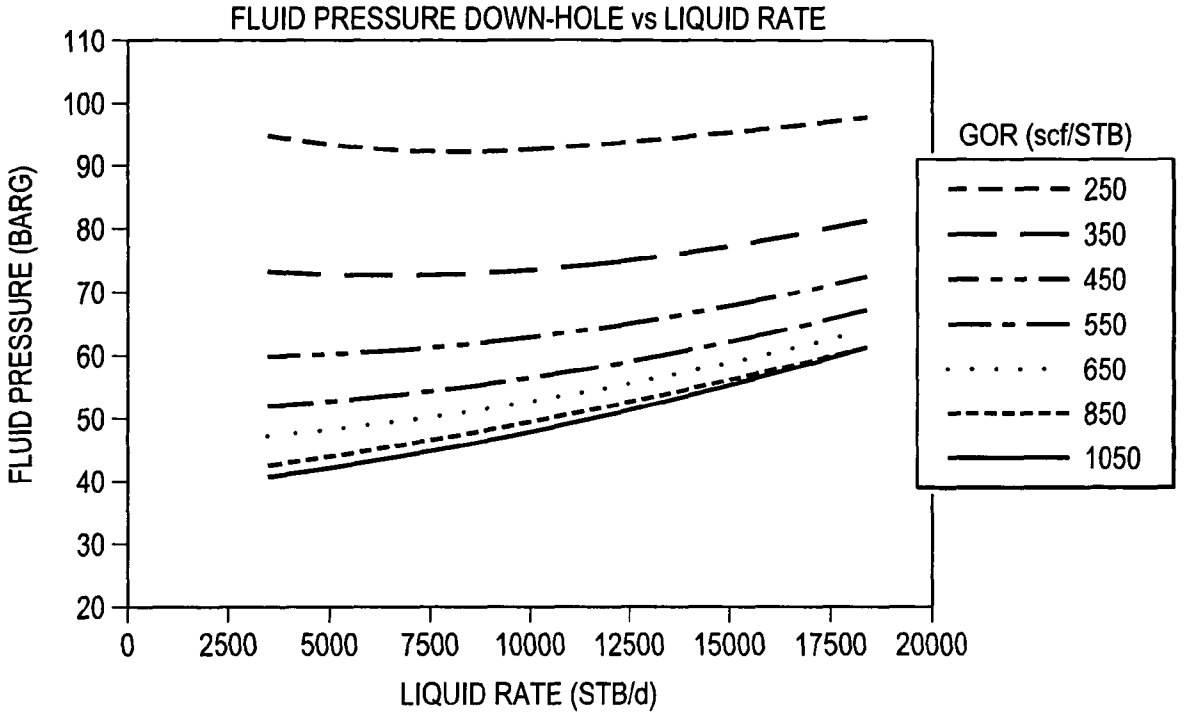


FIG. 10b

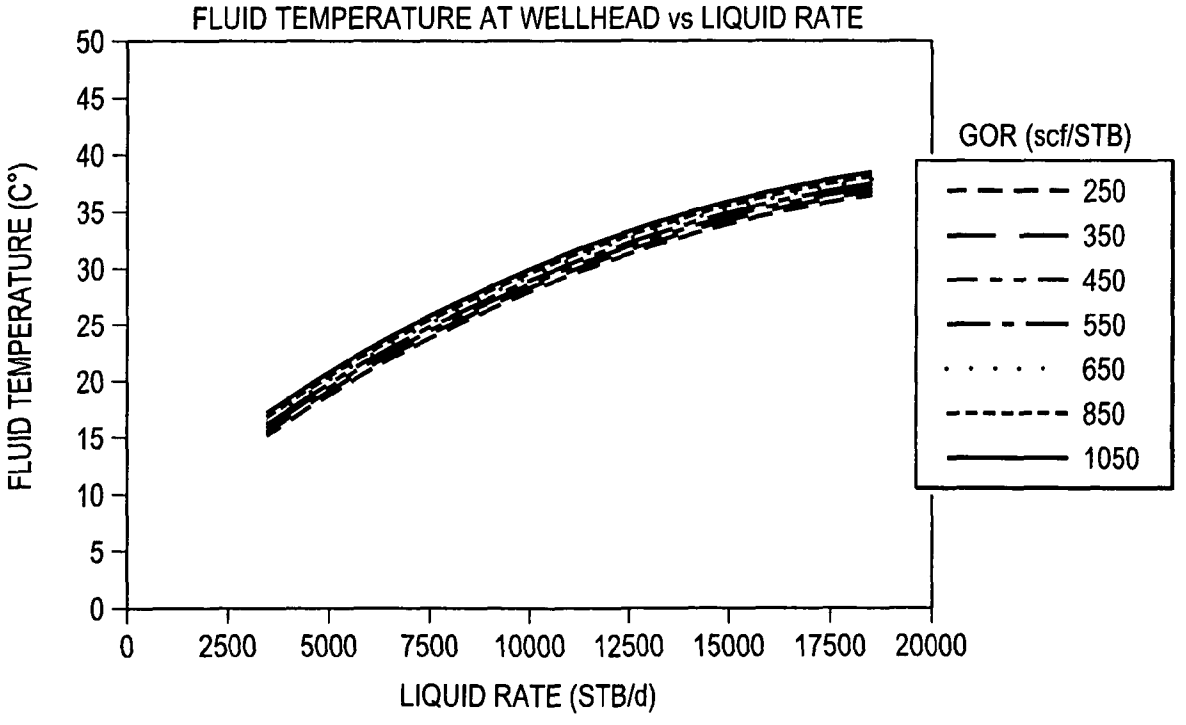
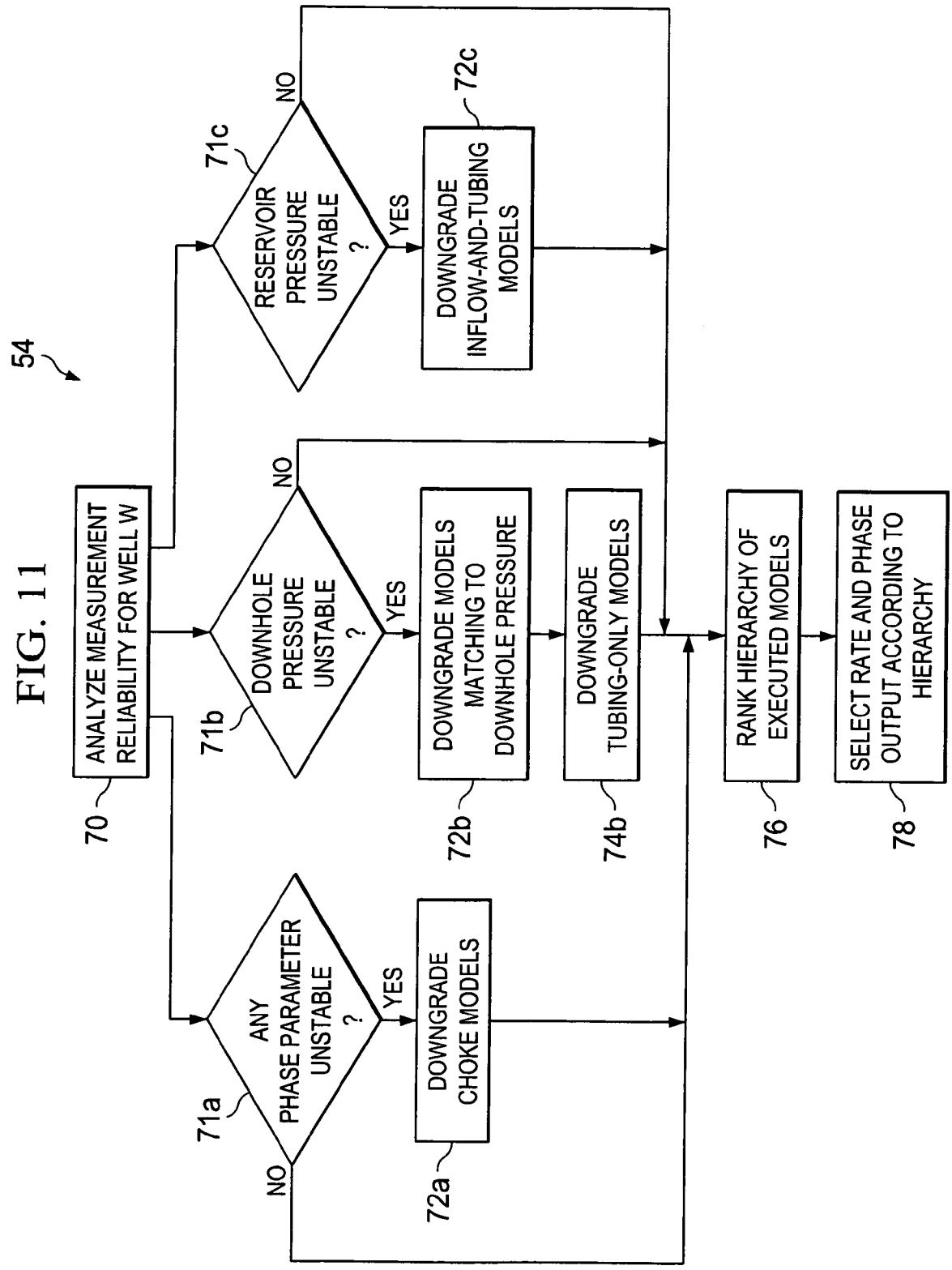


FIG. 11


54
ANALYZE MEASUREMENT RELIABILITY FOR WELL W
70
ANY PHASE PARAMETER UNSTABLE ?
71a
YES
NO
DOWNGRADE CHOKE MODELS
72a
DOWNHOLE PRESSURE UNSTABLE ?
71b
YES
NO
DOWNGRADE MODELS MATCHING TO DOWNHOLE PRESSURE
72b
RESERVOIR PRESSURE UNSTABLE ?
71c
YES
NO
DOWNGRADE INFLOW-AND-TUBING MODELS
72c
DOWNGRADE TUBING-ONLY MODELS
74b
RANK HIERARCHY OF EXECUTED MODELS
76
SELECT RATE AND PHASE OUTPUT ACCORDING TO HIERARCHY
78

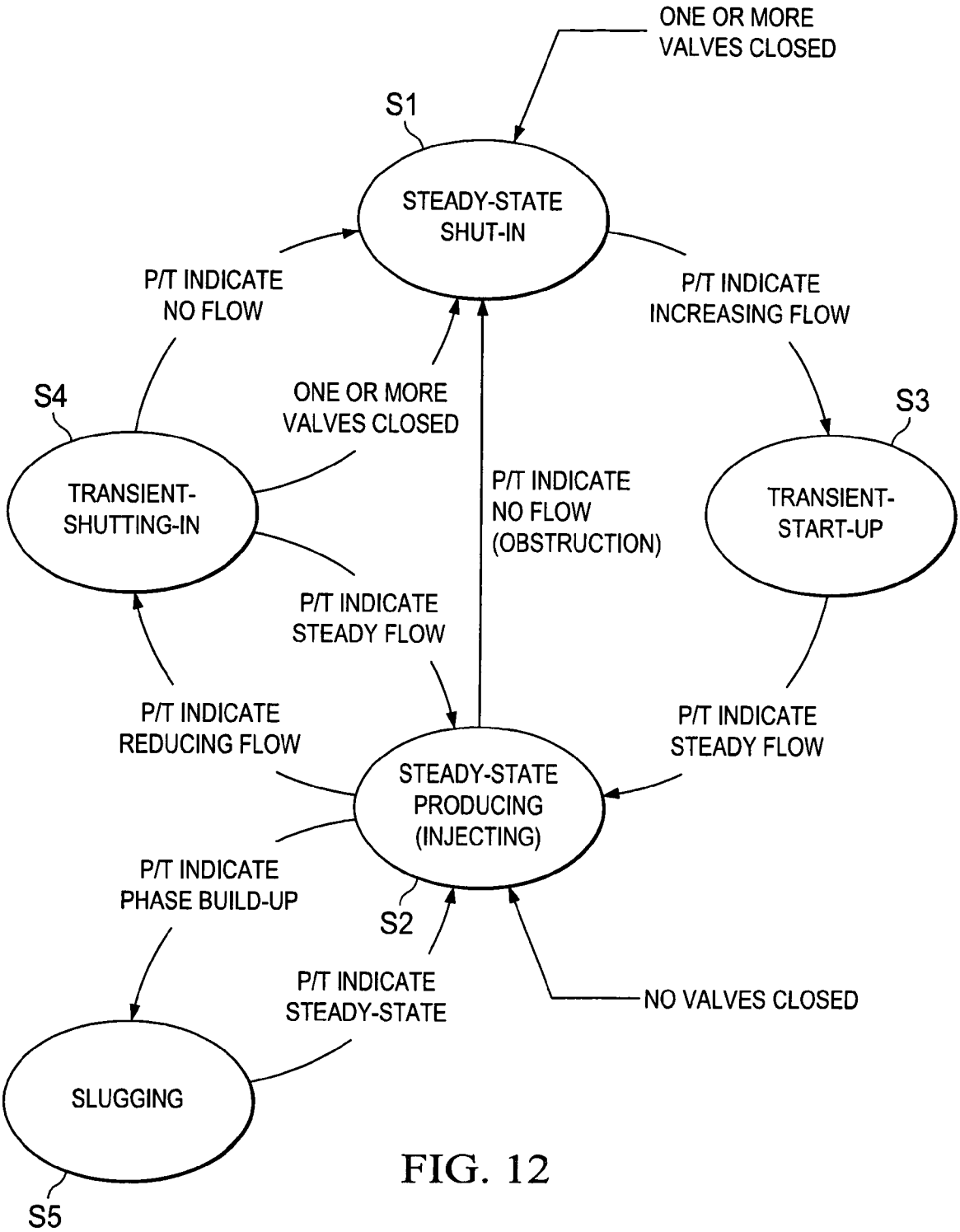

ONE OR MORE VALVES CLOSED
S1
STEADY-STATE SHUT-IN
P/T INDICATE NO FLOW
P/T INDICATE INCREASING FLOW
S4
ONE OR MORE VALVES CLOSED
S3
TRANSIENT-SHUTTING-IN
P/T INDICATE NO FLOW (OBSTRUCTION)
TRANSIENT-START-UP
P/T INDICATE STEADY FLOW
P/T INDICATE REDUCING FLOW
P/T INDICATE STEADY FLOW
STEADY-STATE PRODUCING (INJECTING)
P/T INDICATE PHASE BUILD-UP
S2
P/T INDICATE STEADY-STATE
NO VALVES CLOSED
SLUGGING
S5

FIG. 12

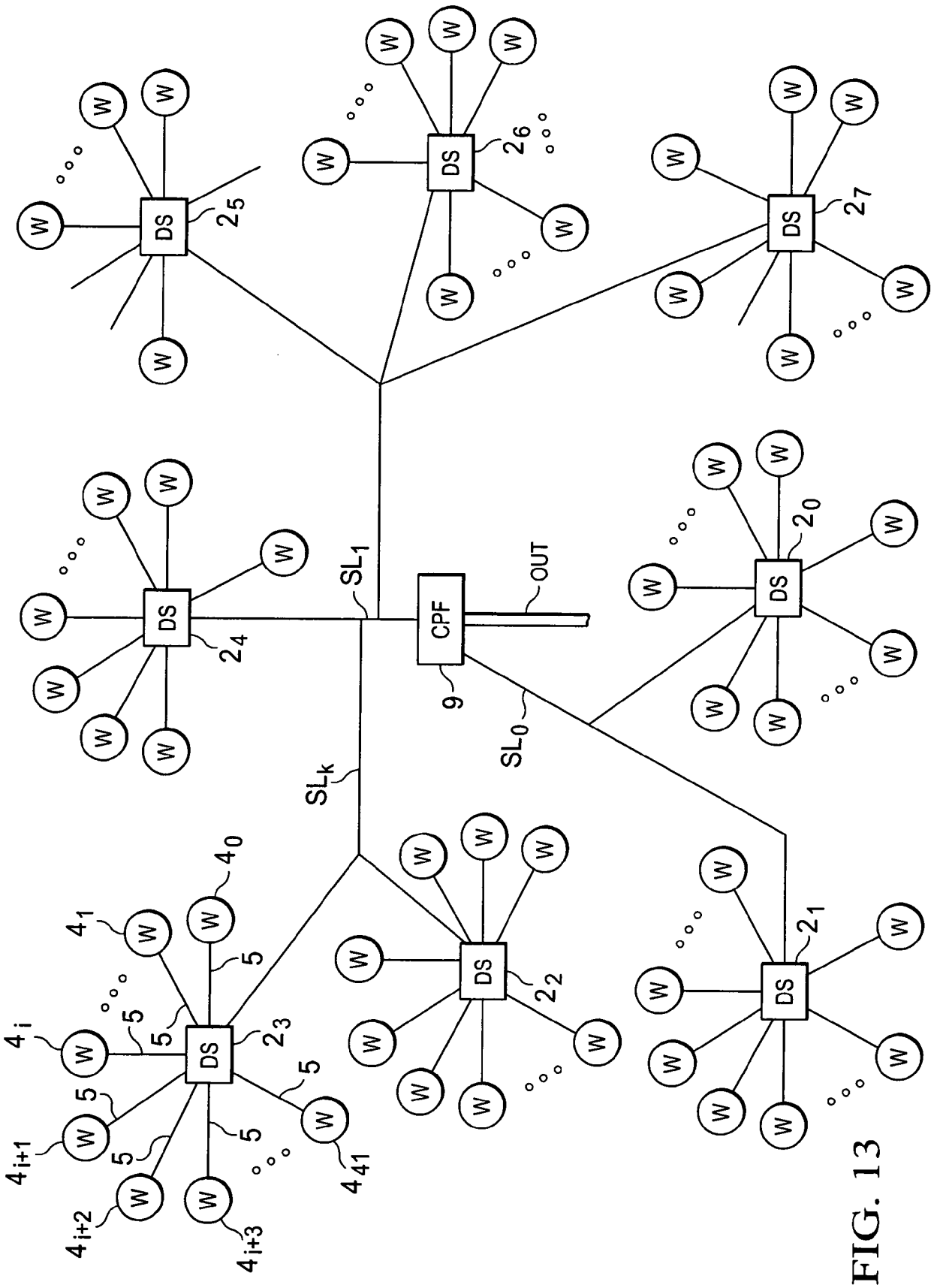

DS
W
CPF
OUT
9
SL_0
SL_1
SL_k
2_0
2_1
2_2
2_3
2_4
2_5
2_6
2_7
4_0
4_1
4_i
4_{i+1}
4_{i+2}
4_{i+3}
4_{41}
5

FIG. 13

FIG. 14

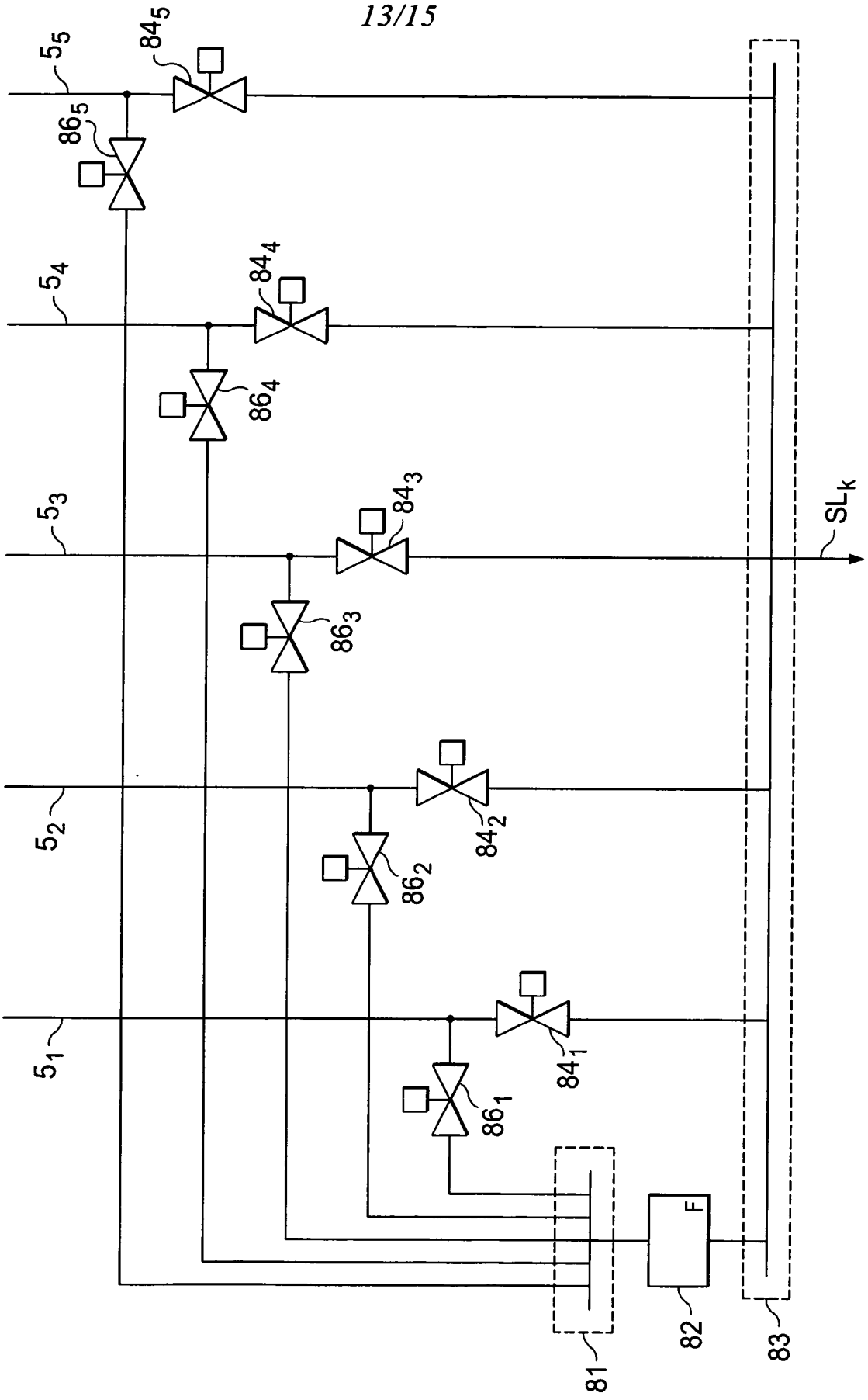
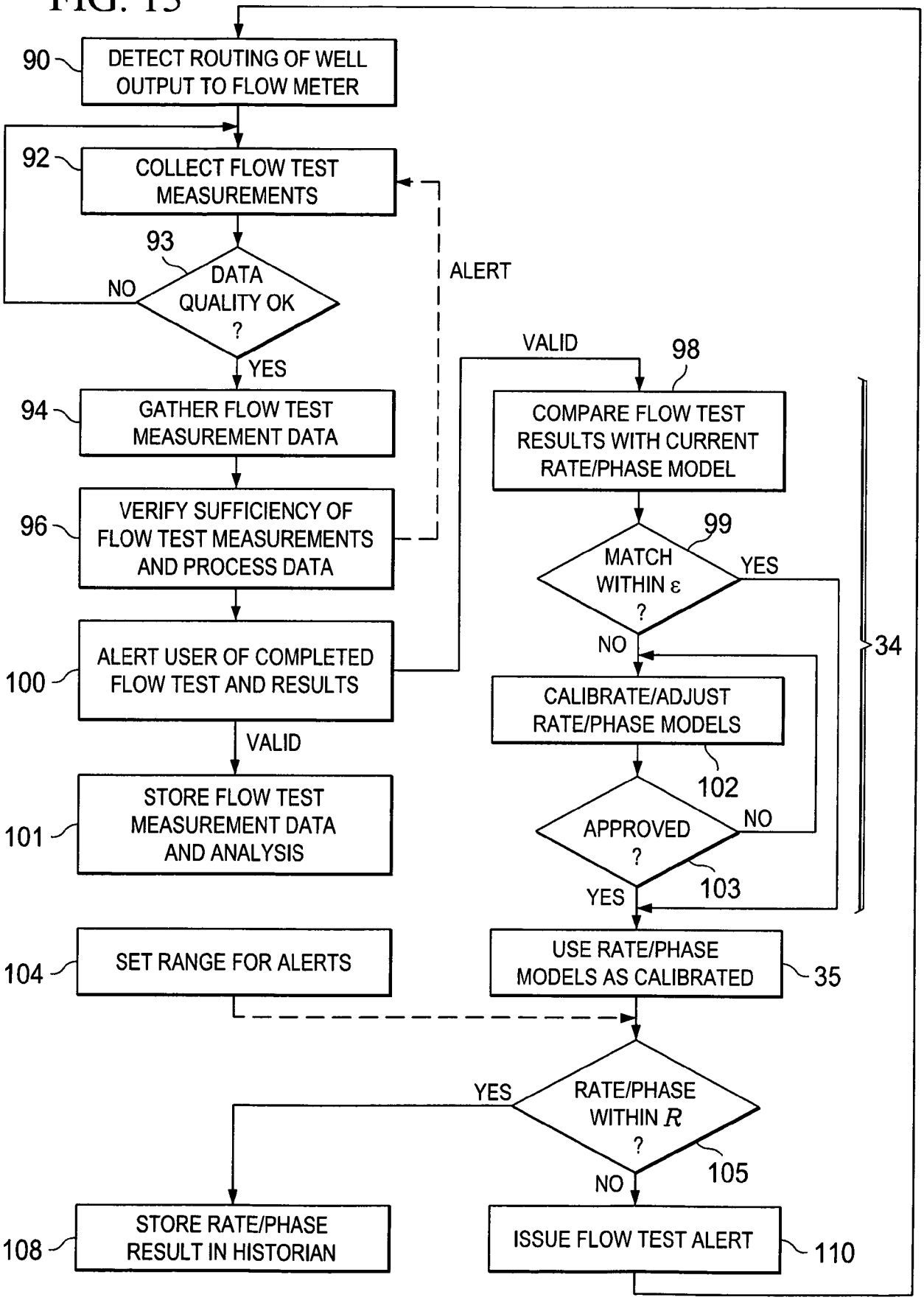

5_5
84_5
86_5
5_4
84_4
86_4
5_3
84_3
86_3
SL_k
5_2
84_2
86_2
5_1
84_1
86_1
F
81
82
83

FIG. 15


90
DETECT ROUTING OF WELL OUTPUT TO FLOW METER
92
COLLECT FLOW TEST MEASUREMENTS
93
DATA QUALITY OK ?
NO
YES
ALERT
94
GATHER FLOW TEST MEASUREMENT DATA
96
VERIFY SUFFICIENCY OF FLOW TEST MEASUREMENTS AND PROCESS DATA
100
ALERT USER OF COMPLETED FLOW TEST AND RESULTS
VALID
101
STORE FLOW TEST MEASUREMENT DATA AND ANALYSIS
104
SET RANGE FOR ALERTS
VALID
98
COMPARE FLOW TEST RESULTS WITH CURRENT RATE/PHASE MODEL
99
MATCH WITHIN ε ?
YES
NO
34
CALIBRATE/ADJUST RATE/PHASE MODELS
102
APPROVED ?
NO
YES
103
USE RATE/PHASE MODELS AS CALIBRATED
35
YES
RATE/PHASE WITHIN R ?
105
NO
108
STORE RATE/PHASE RESULT IN HISTORIAN
ISSUE FLOW TEST ALERT
110

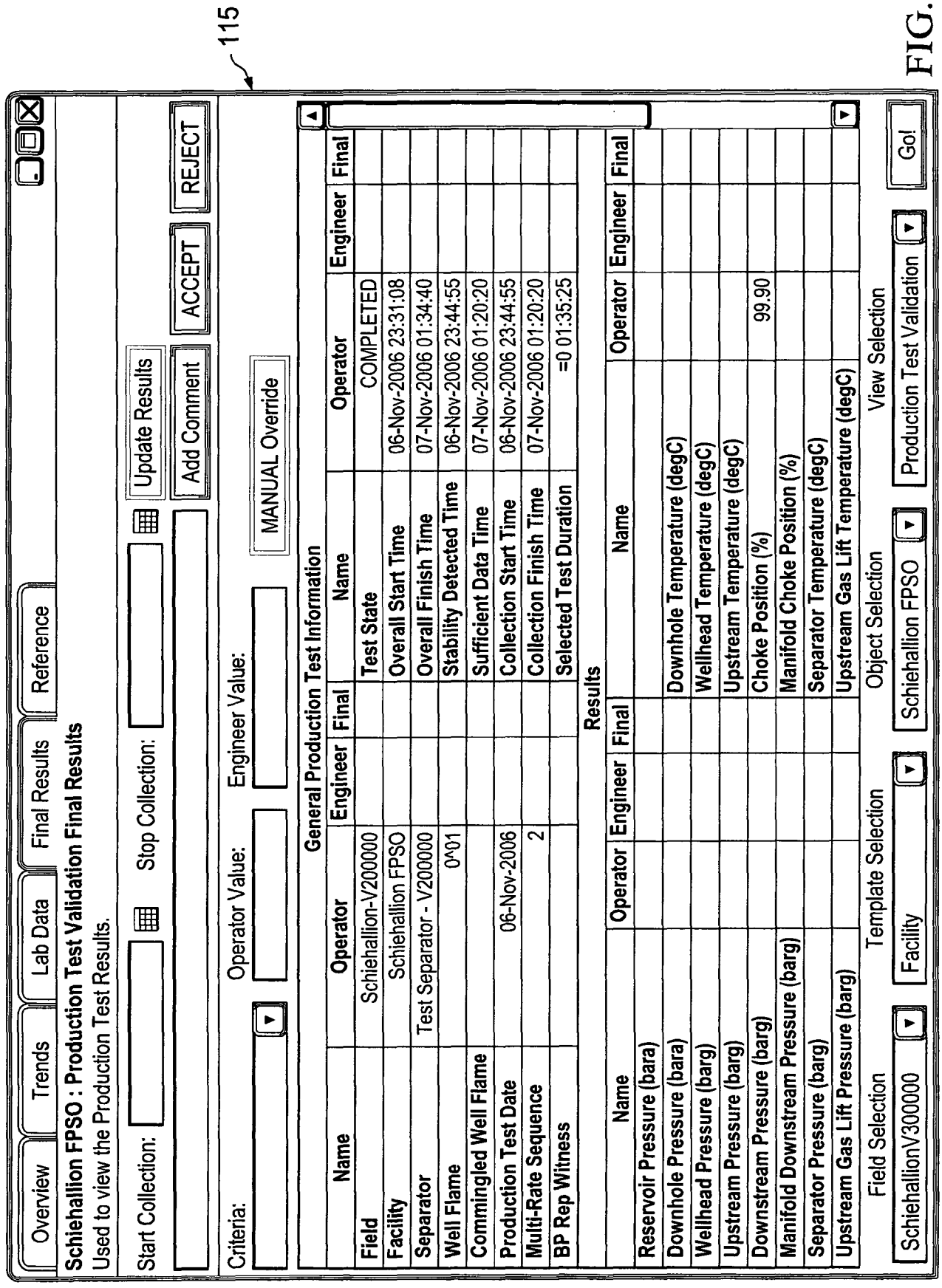

115
Overview
Trends
Lab Data
Final Results
Reference
Schiehallion FPSO : Production Test Validation Final Results
Used to view the Production Test Results.
Start Collection:
Stop Collection:
Update Results
Add Comment
ACCEPT
REJECT
Criteria:
Operator Value:
Engineer Value:
MANUAL Override
General Production Test Information
Name | Operator | Engineer | Final | Name | Operator | Engineer | Final
Field | Schiehallion-V200000 | | | Test State | COMPLETED | |
Facility | Schiehallion FPSO | | | Overall Start Time | 06-Nov-2006 23:31:08 | |
Separator | Test Separator - V200000 | | | Overall Finish Time | 07-Nov-2006 01:34:40 | |
Well Flame | 0^01 | | | Stability Detected Time | 06-Nov-2006 23:44:55 | |
Commingled Well Flame | | | | Sufficient Data Time | 07-Nov-2006 01:20:20 | |
Production Test Date | 06-Nov-2006 | | | Collection Start Time | 06-Nov-2006 23:44:55 | |
Multi-Rate Sequence | 2 | | | Collection Finish Time | 07-Nov-2006 01:20:20 | |
BP Rep Witness | | | | Selected Test Duration | =0 01:35:25 | |
Results
Name | Operator | Engineer | Final | Name | Operator | Engineer | Final
Reservoir Pressure (bara) | | | | Downhole Temperature (degC) | | |
Downhole Pressure (bara) | | | | Wellhead Temperature (degC) | | |
Wellhead Pressure (barg) | | | | Upstream Temperature (degC) | | |
Upstream Pressure (barg) | | | | Choke Position (%) | 99.90 | |
Downstream Pressure (barg) | | | | Manifold Choke Position (%) | | |
Manifold Downstream Pressure (barg) | | | | Separator Temperature (degC) | | |
Separator Pressure (barg) | | | | Upstream Gas Lift Temperature (degC) | | |
Upstream Gas Lift Pressure (barg) | | | |
Field Selection
Template Selection
Object Selection
View Selection
SchiehallionV300000
Facility
Schiehallion FPSO
Production Test Validation
Go!

FIG. 16