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(54) Title: SEISMIC MONITORING OF IN SITU CONVERSION IN A HYDROCARBON CONTAINING FORMATION

(57) Abstract: A method for controlling an in situ system of treating a hydrocarbon containing formation may include monitoring an acoustic event within the formation. More than one acoustic event may be monitored. An acoustic detector placed within a wellbore in the formation or on a surface of the formation may be used to monitor an acoustic event. An acoustic event may be recorded with an acoustic monitoring system and analyzed to determine at least one property of the formation. The in situ system of treating a hydrocarbon containing formation may be controlled based on the analysis of one or more acoustic events. In an embodiment, at least one acoustic event may be a seismic event. In certain embodiments, an acoustic source may be used to generate at least one acoustic event.

SEISMIC MONITORING OF IN SITU CONVERSION IN A HYDROCARBON CONTAINING FORMATION

BACKGROUND OF THE INVENTION

1. Field of the Invention

The present invention generally relates to monitoring and/or controlling an in situ thermal treatment system. More particularly, the invention relates to seismic monitoring to detect fracture formation and progression during in situ heating for production of hydrocarbons, hydrogen, and/or other products from various hydrocarbon containing formations. Certain embodiments relate to control of processes based on seismic monitoring.

2. Description of Related Art

Hydrocarbons obtained from subterranean (e.g., sedimentary) formations are often used as energy resources, as feedstocks, and as consumer products. Concerns over depletion of available hydrocarbon resources and declining overall quality of produced hydrocarbons have led to development of processes for more efficient recovery, processing, and/or use of available hydrocarbon resources. In situ processes may be used to remove hydrocarbon materials from subterranean formations. Chemical and/or physical properties of hydrocarbon material within a subterranean formation may need to be changed to allow hydrocarbon material to be more easily removed from the subterranean formation. The chemical and physical changes may include in situ reactions that produce removable fluids, composition changes, solubility changes, density changes, phase changes, and/or viscosity changes of the hydrocarbon material within the formation. A fluid may be, but is not limited to, a gas, a liquid, an emulsion, a slurry, and/or a stream of solid particles that has flow characteristics similar to liquid flow.

There has been a significant amount of effort to develop methods and systems to economically produce hydrocarbons, hydrogen, and/or other products from hydrocarbon containing formations. At present, however, there are still many hydrocarbon containing formations from which hydrocarbons, hydrogen, and/or other products cannot be economically produced. Production efficiency may be decreased when fractures in the formation extend beyond the treatment area, allowing a significant amount of vapor product to escape from the formation and/or allowing water from an aquifer to flood the treatment area. Seismic monitoring of geophysical changes in a formation (e.g., fracture progression) may provide information needed to adjust treatment such that fractures are substantially contained within the formation.

SUMMARY OF THE INVENTION

A method for controlling an in situ system of treating a hydrocarbon containing formation may include monitoring at least one acoustic event within the formation using at least one acoustic detector placed within a wellbore in the formation. At least one acoustic event may be recorded with an acoustic monitoring system. In an embodiment, an acoustic source may be used to generate at least one acoustic event. The method may also include analyzing the at least one acoustic event to determine at least one property of the formation. The in situ system may be controlled based on the analysis of the at least one acoustic event.

BRIEF DESCRIPTION OF THE DRAWINGS

Advantages of the present invention may become apparent to those skilled in the art with the benefit of the following detailed description of the embodiments and upon reference to the accompanying drawings in which:

FIG. 1 shows a schematic view of an embodiment of a portion of an in situ conversion system for treating a hydrocarbon containing formation.

FIG. 2 illustrates a model of a formation that may be used in simulations of deformation characteristics according to one embodiment.

FIG. 3 illustrates a schematic of a strip development according to one embodiment.

FIG. 4 depicts a schematic illustration of a treated portion that may be modeled with a simulation.

FIG. 5 depicts a horizontal cross section of a model of a formation for use by a simulation method according to one embodiment.

FIG. 6 illustrates a flow chart of an embodiment of a method for modeling deformation due to in situ treatment of a hydrocarbon containing formation.

FIG. 7 depicts a profile of richness versus depth in a model of an oil shale formation.

FIG. 8 illustrates a flow chart of an embodiment of a method for using a computer system to design and control an in situ conversion process.

FIG. 9 illustrates a flow chart of an embodiment of a method for determining operating conditions to obtain desired deformation characteristics.

FIG. 10 illustrates the influence of operating pressure on subsidence in a cylindrical model of a formation from a finite element simulation.

FIG. 11 illustrates influence of an untreated portion between two treated portions.

FIG. 12 illustrates influence of an untreated portion between two treated portions.

FIG. 13 represents shear deformation of a formation at the location of selected heat sources as a function of depth.

FIG. 14 illustrates a method for controlling an in situ process using a computer system.

FIG. 15 illustrates a schematic of an embodiment for controlling an in situ process in a formation using a computer simulation method.

FIG. 16 illustrates several ways that information may be transmitted from an in situ process to a remote computer system.

FIG. 17 illustrates a schematic of an embodiment for controlling an in situ process in a formation using information.

FIG. 18 illustrates a schematic of an embodiment for controlling an in situ process in a formation using a simulation method and a computer system.

FIG. 19 illustrates a flow chart of an embodiment of a computer-implemented method for determining a selected overburden thickness.

FIG. 20 illustrates a schematic diagram of a plan view of a zone being treated using an in situ conversion process.

FIG. 21 illustrates a schematic diagram of a cross-sectional representation of a zone being treated using an in situ conversion process.

FIG. 22 illustrates a flow chart of an embodiment of a method used to monitor treatment of a formation.

FIG. 23 illustrates a schematic of an embodiment used to control an in situ conversion process in a formation.

While the invention is susceptible to various modifications and alternative forms, specific embodiments thereof are shown by way of example in the drawings and may herein be described in detail. The drawings may not be to scale. It should be understood, however, that the drawings and detailed description thereto are not intended to limit the invention to the particular form disclosed, but on the contrary, the intention is to cover all modifications, equivalents and alternatives falling within the spirit and scope of the present invention as defined by the appended claims.

DETAILED DESCRIPTION OF THE INVENTION

The following description generally relates to systems and methods for treating a hydrocarbon containing formation (e.g., a formation containing coal (including lignite, sapropelic coal, etc.), oil shale, carbonaceous shale, shungites, kerogen, bitumen, oil, kerogen and oil in a low permeability matrix, heavy hydrocarbons, asphaltites, natural mineral waxes, formations wherein kerogen is blocking production of other hydrocarbons, etc.). Such formations may be treated to yield relatively high quality hydrocarbon products, hydrogen, and other products. An embodiment generally relates to seismic monitoring to detect fracture formation and progression during in situ heating for production of hydrocarbons, hydrogen, and/or other products from various hydrocarbon containing formations. Certain embodiments relate to control of processes based on seismic monitoring.

"Hydrocarbons" are generally defined as molecules formed primarily by carbon and hydrogen atoms. Hydrocarbons may also include other elements, such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur. Hydrocarbons may be, but are not limited to, kerogen, bitumen, pyrobitumen, oils, natural mineral waxes, and asphaltites. Hydrocarbons may be located within or adjacent to mineral matrices within the earth. Matrices may include, but are not limited to, sedimentary rock, sands, silicilytes, carbonates, diatomites, and other porous media. "Hydrocarbon fluids" are fluids that include hydrocarbons. Hydrocarbon fluids may include, entrain, or be entrained in non-hydrocarbon fluids (e.g., hydrogen ("H_2"), nitrogen ("N_2"), carbon monoxide, carbon dioxide, hydrogen sulfide, water, and ammonia).

A "formation" includes one or more hydrocarbon containing layers, one or more non-hydrocarbon layers, an overburden, and/or an underburden. An "overburden" and/or an "underburden" includes one or more different types of impermeable materials. For example, overburden and/or underburden may include rock, shale, mudstone, or wet/tight carbonate (i.e., an impermeable carbonate without hydrocarbons). In some embodiments of in situ conversion processes, an overburden and/or an underburden may include a hydrocarbon containing layer or hydrocarbon containing layers that are relatively impermeable and are not subjected to temperatures during in situ conversion processing that results in significant characteristic changes of the hydrocarbon containing layers of the overburden and/or underburden. For example, an underburden may contain shale or mudstone. In some cases, the overburden and/or underburden may be somewhat permeable.

"Kerogen" is a solid, insoluble hydrocarbon that has been converted by natural degradation (e.g., by diagenesis) and that principally contains carbon, hydrogen, nitrogen, oxygen, and sulfur. Coal and oil shale are typical examples of materials that contain kerogens. "Bitumen" is a non-crystalline solid or viscous hydrocarbon material that is substantially soluble in carbon disulfide. "Oil" is a fluid containing a mixture of condensable hydrocarbons.

The terms "formation fluids" and "produced fluids" refer to fluids removed from a hydrocarbon containing formation and may include pyrolyzation fluid, synthesis gas, mobilized hydrocarbon, and water (steam). The term "mobilized fluid" refers to fluids within the formation that are able to flow because of thermal treatment of the formation. Formation fluids may include hydrocarbon fluids as well as non-hydrocarbon fluids.

A "heat source" is any system for providing heat to at least a portion of a formation substantially by conductive and/or radiative heat transfer. For example, a heat source may include electric heaters such as an insulated conductor, an elongated member, and/or a conductor disposed within a conduit. A heat source may also include heat sources that generate heat by burning a fuel external to or within a formation, such as surface burners, downhole gas burners, flameless distributed combustors, and natural distributed combustors. In addition, it is envisioned that in some embodiments heat provided to or generated in one or more heat sources may be supplied by other sources of energy. The other sources of energy may directly heat a formation, or the energy may be applied to a transfer media that directly or indirectly heats the formation. It is to be understood that one or more heat sources that are applying heat to a formation may use different sources of energy. For example, for a given formation, some heat sources may supply heat from electric resistance heaters, some heat sources may provide heat from combustion, and some heat sources may provide heat from one or more other energy sources (e.g., chemical reactions, solar energy, wind energy, biomass, or other sources of renewable energy). A chemical reaction may include an exothermic reaction (e.g., an oxidation reaction). A heat source may include a heater that provides heat to a zone proximate and/or surrounding a heating location such as a heater well.

A "heater" is any system for generating heat in a well or a near wellbore region. Heaters may be, but are not limited to, electric heaters, burners, combustors that react with material in or produced from a formation (e.g., natural distributed combustors), and/or combinations thereof. A "unit of heat sources" refers to a number of heat sources that form a template that is repeated to create a pattern of heat sources within a formation.

The term "wellbore" refers to a hole in a formation made by drilling or insertion of a conduit into the formation. A wellbore may have a substantially circular cross section, or other cross-sectional shapes (e.g., circles, ovals, squares, rectangles, triangles, slits, or other regular or irregular shapes). As used herein, the terms "well" and "opening," when referring to an opening in the formation, may be used interchangeably with the term "wellbore."

"Pyrolysis" is the breaking of chemical bonds due to the application of heat. For example, pyrolysis may include transforming a compound into one or more other substances by heat alone. Heat may be transferred to a section of the formation to cause pyrolysis.

"Pyrolyzation fluids" or "pyrolysis products" refers to fluid produced substantially during pyrolysis of hydrocarbons. Fluid produced by pyrolysis reactions may mix with other fluids in a formation. The mixture would be considered pyrolyzation fluid or pyrolyzation product. As used herein, "pyrolysis zone" refers to a volume of a formation (e.g., a relatively permeable formation such as a tar sands formation) that is reacted or reacting to form a pyrolyzation fluid.

"Thermal conductivity" is a property of a material that describes the rate at which heat flows, in steady state, between two surfaces of the material for a given temperature difference between the two surfaces.

"Fluid pressure" is a pressure generated by a fluid within a formation. "Lithostatic pressure" (sometimes referred to as "lithostatic stress") is a pressure within a formation equal to a weight per unit area of an overlying rock mass. "Hydrostatic pressure" is a pressure within a formation exerted by a column of water.

"Subsidence" is a downward movement of a portion of a formation relative to an initial elevation of the surface.

"Thickness" of a layer refers to the thickness of a cross section of a layer, wherein the cross section is normal to a face of the layer.

"Thermal fracture" refers to fractures created in a formation caused by expansion or contraction of a formation and/or fluids within the formation, which is in turn caused by increasing/decreasing the temperature of the formation and/or fluids within the formation, and/or by increasing/decreasing a pressure of fluids within the formation due to heating.

"Vertical hydraulic fracture" refers to a fracture at least partially propagated along a vertical plane in a formation, wherein the fracture is created through injection of fluids into a formation.

FIG. 1 shows a schematic view of an embodiment of a portion of an in situ conversion system for treating a hydrocarbon containing formation. Heat sources 40 may be placed within at least a portion of the hydrocarbon containing formation. Heat sources 40 may include, for example, electric heaters such as insulated conductors, conductor-in-conduit heaters, surface burners, flameless distributed combustors, and/or natural distributed combustors. Heat sources 40 may also include other types of heaters. Heat sources 40 may provide heat to at least a portion of a hydrocarbon containing formation. Energy may be supplied to the heat sources 40 through supply lines 42. The supply lines may be structurally different depending on the type of heat source or heat sources being used to heat the formation. Supply lines for heat sources may transmit electricity for electric heaters, may transport fuel for combustors, or may transport heat exchange fluid that is circulated within the formation.

Production wells 44 may be used to remove formation fluid from the formation. Formation fluid produced from production wells 44 may be transported through collection piping 46 to treatment facilities 48. Formation fluids may also be produced from heat sources 40. For example, fluid may be produced from heat sources 40 to control pressure within the formation adjacent to the heat sources. Fluid produced from heat sources 40 may be transported through tubing or piping to collection piping 46 or the produced fluid may be transported through tubing or piping directly to treatment facilities 48. Treatment facilities 48 may include separation units, reaction units, upgrading units, fuel cells, turbines, storage vessels, and other systems and units for processing produced formation fluids.

An in situ conversion system for treating hydrocarbons may include barrier wells 50. In some embodiments, barriers may be used to inhibit migration of fluids (e.g., generated fluids and/or groundwater) into and/or out of a portion of a formation undergoing an in situ conversion process. Barriers may include, but are not limited to naturally occurring portions (e.g., overburden and/or underburden), freeze wells, frozen barrier zones, low temperature barrier zones, grout walls, sulfur wells, dewatering wells, injection wells, a barrier formed by a gel produced in the formation, a barrier formed by precipitation of salts in the formation, a barrier formed by a polymerization reaction in the formation, sheets driven into the formation, or combinations thereof.

As shown in FIG. 1, in addition to heat sources 40, one or more production wells 44 will typically be placed within the portion of the hydrocarbon containing formation. Formation fluids may be produced through production well 44. In some embodiments, production well 44 may include a heat source. The heat source may heat the portions of the formation at or near the production well and allow for vapor phase removal of formation fluids. The need for high temperature pumping of liquids from the production well may be reduced or eliminated. Avoiding or limiting high temperature pumping of liquids may significantly decrease production costs. Providing heating at or through the production well may: (1) inhibit condensation and/or refluxing of production fluid when such production fluid is moving in the production well proximate the overburden, (2) increase heat input into the formation, and/or (3) increase formation permeability at or proximate the production well. In some in situ conversion process embodiments, an amount of heat supplied to production wells is significantly less than an amount of heat applied to heat sources that heat the formation.

Because permeability and/or porosity increases in the heated formation, produced vapors may flow considerable distances through the formation with relatively little pressure differential. Increases in permeability may result from a reduction of mass of the heated portion due to vaporization of water, removal of hydrocarbons, and/or creation of fractures. Fluids may flow more easily through the heated portion. In some embodiments, production wells may be provided in upper portions of hydrocarbon layers.

Heating of a hydrocarbon containing formation to a pyrolysis temperature range may occur before substantial permeability has been generated within the hydrocarbon containing formation. A pyrolysis temperature range may include temperatures between about 250 °C and about 900 °C. A pyrolysis temperature range for producing desired products may extend through only a portion of the total pyrolysis temperature range. In some embodiments, a pyrolysis temperature range for producing desired products may include temperatures between about 250 °C to about 400 °C.

A heated formation may also be used to produce synthesis gas. Synthesis gas may be produced from the formation prior to or subsequent to producing a formation fluid from the formation. For example, synthesis gas generation may be commenced before and/or after formation fluid production decreases to an uneconomical level. Heat provided to pyrolyze hydrocarbons within the formation may also be used to generate synthesis gas. For example, if a portion of the formation is at a temperature from approximately 270 °C to approximately 375 °C (or 400 °C in some embodiments) after pyrolyzation, then less additional heat is generally required to heat such portion to a temperature sufficient to support synthesis gas generation.

An initial lack of permeability may inhibit the transport of generated fluids from a pyrolysis zone within the formation to a production well. As heat is initially transferred from a heat source to a hydrocarbon containing formation, a fluid pressure within the hydrocarbon containing formation may increase proximate a heat source. Such an increase in fluid pressure may be caused by generation of fluids during pyrolysis of at least some hydrocarbons in the formation. The increased fluid pressure may be released, monitored, altered, and/or controlled through the heat source. For example, the heat source may include a valve that allows for removal of some fluid from the formation. In some heat source embodiments, the heat source may include an open wellbore configuration that inhibits pressure damage to the heat source.

In some in situ conversion process embodiments, pressure generated by expansion of pyrolysis fluids or other fluids generated in the formation may be allowed to increase although an open path to the production well or any other pressure sink may not yet exist in the formation. The fluid pressure may be allowed to increase towards a lithostatic pressure. Fractures in the hydrocarbon containing formation may form when the fluid approaches the lithostatic pressure. For example, fractures may form from a heat source to a production well. The generation of fractures within the heated portion may relieve some of the pressure within the portion.

When permeability or flow channels to production wells are established, pressure within the formation may be controlled by controlling production rate from the production wells. In some embodiments, a back pressure may be maintained at production wells or at selected production wells to maintain a selected pressure within the heated portion.

In an in situ conversion process embodiment, pressure may be increased within a selected section of a portion of a hydrocarbon containing formation to a selected pressure during pyrolysis. A selected pressure may be within a range from about 2 bars absolute to about 72 bars absolute or, in some embodiments, 2 bars absolute to 36 bars absolute. Alternatively, a selected pressure may be within a range from about 2 bars absolute to about 18 bars absolute. In some in situ conversion process embodiments, a majority of hydrocarbon fluids may be produced from a formation having a pressure within a range from about 2 bars absolute to about 18 bars absolute. The pressure during pyrolysis may vary or be varied. The pressure may be varied to alter and/or control a composition of a formation fluid produced, to control a percentage of condensable fluid as compared to non-condensable fluid, and/or to control an API gravity of fluid being produced. For example, decreasing pressure may result in production of a larger condensable fluid component. The condensable fluid component may contain a larger percentage of olefins.

Changes in physical and mechanical properties due to treatment of a formation may result in deformation of the formation. Deformation characteristics may include, but are not limited to, subsidence, compaction, heave, and shear deformation. Heave is a vertical increase at the surface above a treated portion of a formation. Surface displacement may result from several concurrent subsurface effects, such as the thermal expansion of layers of the formation, the compaction of the richest and weakest layers, and the constraining force exerted by cooler rock that surrounds the treated portion of the formation. In general, in the initial stages of heating a formation, the surface above the treated portion may show a heave due to thermal expansion of incompletely pyrolyzed formation material in the treated portion of the formation. As a significant portion of formation becomes pyrolyzed, the formation is weakened and pore pressure in the treated portion declines. The pore pressure is the pressure of the liquid and gas that exists in the pores of a formation. The pore pressure may be influenced by the thermal expansion of the organic matter in the formation and the withdrawal of fluids from the formation. The decrease in the pore pressure tends to increase the effective stress in the treated portion. Since the pore pressure affects the effective stress on the treated portion of a formation, pore pressure influences the extent of subsurface compaction in the formation. Compaction, another deformation characteristic, is a vertical decrease of a subsurface portion above or in the treated portion of the formation. In addition, shear deformation of layers both above and in the treated portion of the formation may also occur. In some embodiments, deformation may adversely affect the in situ treatment process. For example, deformation may damage surface facilities and/or wellbores.

In certain embodiments, an in situ treatment process may be designed and controlled such that the adverse influence of deformation is minimized or substantially eliminated. Computer simulation methods may be useful for design and control of an in situ process since simulation methods may predict deformation characteristics. For example, simulation methods may predict subsidence, compaction, heave, and shear deformation in a formation from a model of an in situ process. The models may include physical, mechanical, and chemical properties of a formation. Simulation methods may be used to study the influence of properties of a formation, operating conditions, and process characteristics on deformation characteristics of the formation.

FIG. 2 illustrates model 52 of a formation that may be used in simulations of deformation characteristics according to one embodiment. The formation model is a vertical cross section that may include treated portions 54 with thickness 56 and width or radius 58. Treated portion 54 may include several layers or regions that vary in mineral composition and richness of organic matter. For example, in a model of an oil shale formation, treated portion 54 may include layers of lean kerogenous chalk, rich kerogenous chalk, and silicified kerogenous chalk. In one embodiment, treated portion 54 may be a dipping coal seam that is at an angle to the surface of the formation. The model may also include untreated portions such as overburden 60 and base rock 62. Overburden 60 may have thickness 64. Overburden 60 may also include one or more portions, for example, portion 66 and portion 66' that differ in composition. In an example, portion 66' may have a composition similar to treated portion 54 prior to treatment. Portion 66 may be composed of organic material, soil, rock, etc. Base rock 62 may include barren rock with at least some organic material.

In some embodiments, an in situ process may be designed such that it includes an untreated portion or strip between treated portions of the formation. FIG. 3 illustrates a schematic of a strip development according to one embodiment. The formation includes treated portion 54 and treated portion 54' with thicknesses 56, 56' and widths 58, 58', respectively (thicknesses 56, 56' and widths 58, 58' may vary between portion 54 and portion 54'). Untreated portion 68 with width 70 separates treated portion 54 from treated portion 54'. In some embodiments, width 70 is substantially less than widths 58, 58' since only smaller sections may need to remain untreated to provide structural support. In some embodiments, the use of an untreated portion may decrease the amount of subsidence, heave, compaction, or shear deformation at and above the treated portions of the formation.

In an embodiment, an in situ treatment process may be represented by a three-dimensional model. FIG. 4 depicts a schematic illustration of a treated portion that may be modeled with a simulation. The treated portion includes a well pattern with heat sources 40 and production wells 44. Dashed lines 72 correspond to three planes of symmetry that may divide the pattern into six equivalent sections. Solid lines between heat sources 40 merely depict the pattern of heat sources (i.e., the solid lines do not represent actual equipment between the heat sources). In some embodiments, a geomechanical model of the pattern may include one of the six symmetry segments.

FIG. 5 depicts a cross section of a model of a formation for use by a simulation method according to one embodiment. The model includes grid elements 74. Treated portion 54 is located in the lower left corner of the model. Grid elements in the treated portion may be sufficiently small to take into account the large variations in conditions in the treated portion. In addition, distance 76 and distance 76' may be sufficiently large such that the deformation furthest from the treated portion is substantially negligible. Alternatively, a model may be approximated by a shape, such as a cylinder. The diameter and height of the cylinder may correspond to the size and height of the treated portion.

In certain embodiments, heat sources may be modeled by line sources that inject heat at a fixed rate. The heat sources may generate a reasonably accurate temperature distribution in the vicinity of the heat sources. Alternatively, a time-dependent temperature distribution may be imposed as an average boundary condition.

FIG. 6 illustrates a flow chart of an embodiment of method 78 for modeling deformation due to treatment of a hydrocarbon containing formation in situ. The method may include providing at least one property 80 of the formation to a computer system. The formation may include a treated portion and an untreated portion. Properties may include mechanical, chemical, thermal, and physical properties of the portions of the formation. For example, the mechanical properties may include compressive strength, confining pressure, creep parameters, elastic modulus, Poisson's ratio, cohesion stress, friction angle, and cap eccentricity. Thermal and physical properties may include a coefficient of thermal expansion, volumetric heat capacity, and thermal conductivity. Properties may also include the porosity, permeability, saturation, compressibility, and density of the formation. Chemical properties may include, for example, the richness and/or organic content of the portions of the formation.

In addition, at least one operating condition 82 may be provided to the computer system. For instance, operating conditions may include, but are not limited to, pressure, temperature, process time, rate of pressure increase, heating rate, and characteristics of the well pattern. In addition, an operating condition may include the overburden thickness, and thickness and width (or radius) of the treated portion of the formation. An operating condition may also include untreated portions between treated portions of the formation, along with the horizontal distance between treated portions of a formation.

In certain embodiments, the properties may include initial properties of the formation. Furthermore, the model may include relationships for the dependence of the mechanical, thermal, and physical properties on conditions such as temperature, pressure, and richness in the portions of the formation. For example, the compressive strength in the treated portion of the formation may be a function of richness, temperature, and pressure. The volumetric heat capacity may depend on the richness and the coefficient of thermal expansion may be a function of the temperature and richness. Additionally, the permeability, porosity, and density may be dependent upon the richness of the formation.

In some embodiments, physical and mechanical properties for a model of a formation may be assessed from samples extracted from a geological formation targeted for treatment. Properties of the samples may be measured at various temperatures and pressures. For example, mechanical properties may be measured using uniaxial, triaxial, and creep experiments. In addition, chemical properties (e.g., richness) of the samples may also be measured. Richness of the samples may be measured by the Fischer Assay method. The dependence of properties on temperature, pressure, and richness may then be assessed from the measurements. In certain embodiments, the properties may be mapped on to a model using known sample locations. For instance, FIG. 7 depicts a profile of richness versus depth in a model of an oil shale formation. The treated portion is represented by region 54. Similarly, the overburden and base rock are represented by region 60 and region 62, respectively. In FIG. 7, richness is measured in m^3 of kerogen per metric ton of oil shale.

In certain embodiments, assessing deformation using a simulation method may require a material or constitutive model. A constitutive model relates the stress in the formation to the strain or displacement. Mechanical properties may be entered into a suitable constitutive model to calculate the deformation of the formation. In one embodiment, the Drucker-Prager-with-cap material model may be used to model the time-independent deformation of the formation.

In an embodiment, the time-dependent creep or secondary creep strain of the formation may also be modeled. For example, the time-dependent creep in a formation may be modeled with a power law in EQN. 1:

$$(1)\ \varepsilon = C \times (\sigma_1 - \sigma_3)^D \times t,$$

where ε is the secondary creep strain, C is a creep multiplier, σ_1 is the axial stress, σ_3 is the confining pressure, D is a stress exponent, and t is the time. The values of C and D may be obtained from fitting experimental data. In one embodiment, the creep rate may be expressed by EQN. 2:

$$(2)\ d\varepsilon/dt = A \times (\sigma_1/\sigma_u)^D,$$

where A is a multiplier obtained from fitting experimental data and σ_u is the ultimate strength in uniaxial compression.

The method shown in FIG. 6 may further include assessing 84 at least one process characteristic 86 of the treated portion of the formation. At least one process characteristic 86 may include a pore pressure distribution, a heat input rate, or a time dependent temperature distribution in the treated portion of the formation.

At least one process characteristic may be assessed by a simulation method. For example, a heat input rate may be estimated using a body-fitted finite difference simulation package such as FLUENT (FLUENT Inc.; Labanon, New Hampshire). Similarly, the pore pressure distribution may be assessed from a space-fitted or body-fitted simulation method such as STARS (Computer Modeling Group; Alberta, Canada). In other embodiments, the pore pressure may be assessed by a finite element simulation method such as ABAQUS (Hibbitt, Karlsson & Sorensen, Inc.; Pawtucket, Rhode Island). The finite element simulation method may employ line sinks of fluid to simulate the performance of production wells.

Alternatively, process characteristics such as temperature distribution and pore pressure distribution may be approximated by other means. For example, the temperature distribution may be imposed as an average boundary condition in the calculation of deformation characteristics. The temperature distribution may be estimated from results of detailed calculations of a heating rate of a formation. For example, a treated portion may be heated to a pyrolyzation temperature for a specified period of time by heat sources and the temperature distribution assessed during heating of the treated portion. In an embodiment, the heat sources may be uniformly distributed and inject a constant amount of heat. The temperature distribution inside most of the treated portion may be substantially uniform during the specified period of time. Some heat may be allowed to diffuse from the treated portion into the overburden, base rock, and lateral rock. The treated portion may be maintained at a selected temperature for a selected period of time after the specified period of time by injecting heat from the heat sources as needed.

Similarly, the pore pressure distribution may also be imposed as an average boundary condition. The initial pore pressure distribution may be assumed to be lithostatic. The pore pressure distribution may then be gradually reduced to a selected pressure during the remainder of the simulation of the deformation characteristics.

In some embodiments, as shown in FIG. 6, the method may include assessing at least one deformation characteristic 88 of the formation using simulation method 90 on the computer system as a function of time. At least one deformation characteristic may be assessed from at least one property 80, at least one process characteristic 86, and at least one operating condition 82. In certain embodiments, process characteristic 86 may be assessed by a simulation or process characteristic 86 may be measured. Deformation characteristics may include, but are not limited to, subsidence, compaction, heave, and shear deformation in the formation.

Simulation method 90 may be a finite element simulation method for calculating elastic, plastic, and time dependent behavior of materials. For example, ABAQUS is a commercially available finite element simulation method from. ABAQUS is capable of describing the elastic, plastic, and time dependent (creep) behavior of a broad class of materials such as mineral matter, soils, and metals. In general, ABAQUS may describe materials whose properties are specified by user-defined constitutive laws. ABAQUS may be used to calculate heat transfer and the effect of pore pressure variations on rock deformation.

Computer simulations may be used to assess operating conditions of an in situ process in a formation that results in desired deformation characteristics. FIG. 8 illustrates a flow chart of an embodiment of method 92 for designing and controlling an in situ process using a computer system. The method may include providing to the computer system at least one set of operating conditions 82 for the in situ process. For instance, operating conditions may include pressure, temperature, process time, rate of pressure increase, heating rate, characteristics of the well pattern, the overburden thickness, thickness and width of the treated portion of the formation and/or untreated portions between treated portions of the formation, and the horizontal distance between treated portions of a formation.

In addition, at least one desired deformation characteristic 88 for the in situ process may be provided to the computer system. The desired deformation characteristic may be a selected subsidence, selected heave, selected compaction, or selected shear deformation. In some embodiments, at least one additional operating condition 82' may be assessed using simulation method 90 to produce at least one desired deformation characteristic 88. A desired deformation characteristic may be a value that does not adversely affect the operation of an in situ process. For example, a minimum overburden necessary to achieve a desired maximum value of subsidence may be assessed. In an embodiment, at least one additional operating condition 82' may be used to operate in situ process 94.

In one embodiment, operating conditions to obtain desired deformation characteristics may be assessed from simulations of an in situ process based on multiple operating conditions. FIG. 9 illustrates a flow chart of an embodiment of method 96 for assessing operating conditions to obtain desired deformation characteristics. The method may include providing one or more values of at least one operating condition 82 to a computer system for use as input to simulation method 90. The simulation method may be a finite element simulation method for calculating elastic, plastic, and creep behavior.

In some embodiments, the method may include assessing one or more values of deformation characteristics 88 using simulation method 90 based on one or more values of at least one operating condition 82. In one embodiment, a value of at least one deformation characteristic may include the deformation characteristic as a function of time. A desired value of at least one deformation characteristic 88' for the in situ process may also be provided to the computer system. An embodiment may include assessing 84 desired value of at least one operating condition 82' to achieve desired value of at least one deformation characteristic 88'.

Desired value of at least one operating condition 82' may be assessed from the values of at least one deformation characteristic 88 and the values of at least one operating condition 82. For example, desired value of operating condition 82' may be obtained by interpolation of values of deformation characteristic 88 and values of operating condition 82. In some embodiments, a value of at least one deformation characteristic may be assessed 98 from the desired value of at least one operating condition 82' using simulation method 90. In some embodiments, an operating condition to achieve a desired deformation characteristic may be assessed by comparing a deformation characteristic as a function of time for different operating conditions.

In an alternative embodiment, a desired value of at least one operating condition to achieve the desired value of at least one deformation characteristic may be assessed using a relationship between at least one deformation characteristic and at least one operating condition of the in situ process. The relationship may be assessed using a simulation method. Such relationship may be stored on a database accessible by the computer system. The relationship may include one or more values of at least one deformation characteristic and corresponding values of at least one operating condition. Alternatively, the relationship may be an analytical function.

Simulations have been used to investigate the effect of various operating conditions on the deformation characteristics of an oil shale formation. In one set of simulations, the formation was modeled as either a cylinder or a rectangular slab. In the case of a cylinder, the model of the formation is described by a thickness of the treated portion, a radius, and a thickness of the overburden. The rectangular slab is described by a width rather than a radius and by a thickness of the treated section and overburden. FIG. 10 illustrates the influence of operating pressure on subsidence in a cylindrical model of a formation from a finite element simulation. The thickness of the treated portion is 189 m, the radius of the treated portion is 305 m, and the overburden thickness is 201 m. FIG. 10 shows the vertical surface displacement in meters over a period of years. Curve 100 corresponds to an operating pressure of 27.6 bars absolute and curve 102 corresponds to an operating pressure of 6.9 bars absolute. It is to be understood that the surface displacements set forth in FIG. 10 are only illustrative (actual surface displacements will generally differ from those shown in FIG. 10). FIG. 10 demonstrates, however, that increasing the operating pressure may substantially reduce subsidence.

FIGS. 11 and 12 illustrate the influence of the use of an untreated portion between two treated portions. FIG. 11 is the subsidence in a rectangular slab model with a treated portion thickness of 189 m, treated portion width of 649 m, and overburden thickness of 201 m. FIG. 12 represents the subsidence in a rectangular slab model with two treated portions separated by an untreated portion, as pictured in FIG. 3. The thickness of the treated portion and the overburden are the same as the model corresponding to FIG. 11. The width of each treated portion is one half of the width of the treated portion of the model in FIG. 11. Therefore, the total width of the treated portions is the same for each model. The operating pressure in each case is 6.9 bars absolute. As with FIG. 10, the surface displacements in FIGS. 11 and 12 are only illustrative. A comparison of FIGS. 11 and 12, however, shows that the use of an untreated portion reduces the subsidence by about 25%. In addition, the initial heave is also reduced.

In another set of simulations, the calculation of the shear deformation in a treated oil shale formation was demonstrated. The model included a symmetry element of a pattern of heat sources and producer wells. Boundary conditions imposed in the model were such that the vertical planes bounding the formation were symmetry planes. FIG. 13 represents the shear deformation of the formation at the location of selected heat sources as a function of depth. Curve 104 and curve 106 represent the shear deformation as a function of depth at 10 months and 12 months, respectively. The curves, which correspond to the predicted shape of the heat injection wells, show that shear deformation increases with depth in the formation.

In certain embodiments, a computer system may be used to operate an in situ process for treating a hydrocarbon containing formation. The in situ process may include providing heat from one or more heat sources to at least one portion of the formation. In addition, the in situ process may also include allowing the heat to transfer from the one or more heat sources to a selected section of the formation. FIG. 14 illustrates method 108 for operating an in situ process using a computer system. The method may include operating in situ process 94 using one or more operating parameters. Operating parameters may include properties of the formation, such as heat capacity, density, permeability, thermal conductivity, porosity, and/or chemical reaction data. In addition, operating parameters may include operating conditions. Operating conditions may include, but are not limited to, thickness and area of heated portion of the formation, pressure, temperature, heating rate, heat input rate, process time, production rate, time to obtain a given production rate, weight percentage of gases, and/or peripheral water recovery or injection. Operating conditions may also include characteristics of the well pattern such as producer well location, producer well orientation, ratio of producer wells to heater wells, heater well spacing, type of heater well pattern, heater well orientation, and/or distance between an overburden and horizontal heater wells. Operating parameters may also include mechanical properties of the formation. Operating parameters may include deformation characteristics, such as fracture, strain, subsidence, heave, compaction, and/or shear deformation.

In certain embodiments, at least one operating parameter 110 of in situ process 94 may be provided to computer system 112. Computer system 112 may be at or near in situ process 94. Alternatively, computer system 112 may be at a location remote from in situ process 94. The computer system may include a first simulation method for simulating a model of in situ process 94. The first simulation method may include a body-fitted finite difference simulation method such as FLUENT or space-fitted finite difference simulation method such as STARS. The first simulation method may perform a reservoir simulation. A reservoir simulation method may be used to determine operating parameters including, but not limited to, pressure, temperature, heating rate, heat input rate, process time, production rate, time to obtain a given production rate, weight percentage of gases, and peripheral water recovery or injection.

In an embodiment, the first simulation method may also calculate deformation in a formation. A simulation method for calculating deformation characteristics may include a finite element simulation method such as ABAQUS. The first simulation method may calculate fracture progression, strain, subsidence, heave, compaction, and shear deformation. A simulation method used for calculating deformation characteristics may include method 78 illustrated in FIG. 6 and/or method 96 illustrated in FIG. 9.

The method illustrated in FIG. 14 may further include using at least one parameter 110 with a first simulation method and the computer system to provide assessed information 114 about in situ process 94. Operating parameters from the simulation may be compared to operating parameters of in situ process 94. Assessed information from a simulation may include a simulated relationship between one or more operating parameters with at least one parameter 110. For example, the assessed information may include a relationship between operating parameters such as pressure, temperature, heating input rate, or heating rate and operating parameters relating to product quality.

In some embodiments, assessed information may include inconsistencies between operating parameters from simulation and operating parameters from in situ process 94. For example, the temperature, pressure, product quality, or production rate from the first simulation method may differ from in situ process 94. The source of the inconsistencies may be assessed from the operating parameters provided by simulation. The source of the inconsistencies may include differences between certain properties used in a simulated model of in situ process 94 and in situ process 94. Certain properties may include, but are not limited to, thermal conductivity, heat capacity, density, permeability, or chemical reaction data. Certain properties may also include mechanical properties such as compressive strength, confining pressure, creep parameters, elastic modulus, Poisson's ratio, cohesion stress, friction angle, and cap eccentricity.

In one embodiment, assessed information may include adjustments in one or more operating parameters of in situ process 94. The adjustments may compensate for inconsistencies between simulated operating parameters and operating parameters from in situ process 94. Adjustments may be assessed from a simulated relationship between at least one parameter 110 and one or more operating parameters.

For example, an in situ process may have a particular hydrocarbon fluid production rate, e.g., 1 m^3/day, after a particular period of time (e.g., 90 days). A theoretical temperature at an observation well (e.g., 100 °C) may be calculated using given properties of the formation. However, a measured temperature at an observation well (e.g., 80 °C) may be lower than the theoretical temperature. A simulation on a computer system may be performed using the measured temperature. The simulation may provide operating parameters of the in situ process that correspond to the measured temperature. The operating parameters from simulation may be used to assess a relationship between, for example, temperature or heat input rate and the production rate of the in situ process. The relationship may indicate that the heat capacity or thermal conductivity of the formation used in the simulation is inconsistent with the formation.

In some embodiments, the method may further include using assessed information 114 to operate in situ process 94. As used herein, "operate" refers to controlling or changing operating conditions of an in situ process. For example, the assessed information may indicate that the thermal conductivity of the formation in the above example is lower than the thermal conductivity used in the simulation. Therefore, the heat input rate to in situ process 94 may be increased to operate at the theoretical temperature.

In other embodiments, the method may include obtaining 116 information 118 from a second simulation method and the computer system using assessed information 114 and desired parameter 120. In one embodiment, the first simulation method may be the same as the second simulation method. In another embodiment, the first and second simulation methods may be different. Simulations may provide a relationship between at least one operating parameter and at least one other parameter. Additionally, obtained information 118 may be used to operate in situ process 94.

Obtained information 118 may include at least one operating parameter for use in the in situ process that achieves the desired parameter. For example, a desired hydrocarbon fluid production rate for an in situ process may be 6 m^3/day. One or more simulations may be used to determine the operating parameters necessary to achieve a hydrocarbon fluid production rate of 6 m^3/day. In some embodiments, model parameters used by a simulation method may be calibrated to account for differences observed between simulations and in situ process 94. In an embodiment, simulation method 96 illustrated in FIG. 9 may be used to obtain at least one operating parameter that achieves a desired deformation characteristic.

FIG. 15 illustrates a schematic of an embodiment for controlling in situ process 94 in a formation using a computer simulation method. In situ process 94 may include sensor 122 for monitoring operating parameters. Sensor 122 may be located in a barrier well, a monitoring well, a production well, or a heater well. Sensor 122 may monitor operating parameters such as subsurface and surface conditions in the formation. Subsurface conditions may include pressure, temperature, product quality, and deformation characteristics, such as fracture progression. Sensor 122 may also monitor surface data such as pump status (i.e., on or off), fluid flow rate, surface pressure/temperature, and heater power. The surface data may be monitored with instruments placed at a well.

In addition, at least one operating parameter 110 measured by sensor 122 may be provided to local computer system 112'. Alternatively, operating parameter 110 may be provided to remote computer system 112". Computer system 112" may be, for example, a personal desktop computer system, a laptop, or personal digital assistant such as a palm pilot. FIG. 16 illustrates several ways that information such as an operating parameter may be transmitted from in situ process 94 to remote computer system 112". Information may be transmitted by means of internet 124, hardwire telephone lines 126, and/or wireless communications 128. Wireless communications 128 may include transmission via satellite 130.

In some embodiments, as shown in FIG. 15, operating parameter 110 may be provided to computer system 112' or 112" automatically during the treatment of a formation. Computer systems 112' and 112" may include a simulation method for simulating a model of in situ treatment process 94. The simulation method may be used to obtain information 118 about the in situ process.

In an embodiment, a simulation of in situ process 94 may be performed manually at a desired time. Alternatively, a simulation may be performed automatically when a desired condition is met. For instance, a simulation may be performed when one or more operating parameters reach, or fail to reach, a particular value at a particular time. For example, a simulation may be performed when the production rate fails to reach a particular value at a particular time.

In some embodiments, information 118 relating to in situ process 94 may be provided automatically by computer system 112' or 112" for use in controlling in situ process 94. Information 118 may include instructions relating to control of in situ process 94. Information 118 may be transmitted from computer system 112" via internet, hardwire, wireless, or satellite transmission. Information 118 may be provided to computer system 112. Computer system 112 may also be at a location remote from the in situ process. Computer system 112 may process information 118 for use in controlling in situ process 94. For example, computer system 112 may use information 118 to determine adjustments in one or more operating parameters. Computer system 112 may then automatically adjust 132 one or more operating parameters of in situ process 94. Alternatively, one or more operating parameters of in situ process 94 may be displayed and then, optionally, adjusted manually 134.

FIG. 17 illustrates a schematic of an embodiment for controlling in situ process 94 in a formation using information 118. Information 118 may be obtained using a simulation method and a computer system. Information 118 may be provided to computer system 112. Information 118 may include information that relates to adjusting one or more operating parameters. Output 136 from computer system 112 may be provided to display 138, data storage 140, or surface facility 142. Output 136 may also be used to automatically control conditions in the formation by adjusting one or more operating parameters. Output 136 may include instructions to adjust pump status and flow rate at a barrier well 50, adjust pump status and flow rate at a production well 44, and/or adjust the heater power at heater well 144. Output 136 may also include instructions to heating pattern 146 of in situ process 94. For example, an instruction may be to add one or more heater wells at particular locations. In addition, output 136 may include instructions to shut-in formation 148.

Alternatively, output 136 may be viewed by operators of the in situ process on display 138. The operators may then use output 136 to manually adjust one or more operating parameters.

FIG. 18 illustrates a schematic of an embodiment for controlling in situ process 94 in a formation using a simulation method and a computer system. At least one operating parameter 110 from in situ process 94 may be provided to computer system 112. Computer system 112 may include a simulation method for simulating a model of in situ process 94. Computer system 112 may use the simulation method to obtain information 118 about in situ process 94. Information 118 may be provided to data storage 140, display 138, and analysis 150. In an embodiment, information 118 may be automatically provided to in situ process 94. Information 118 may then be used to operate in situ process 94.

Analysis 150 may include review and/or use of information 118 to operate in situ process 94. Analysis 150 may include obtaining additional information 118' using one or more simulations 90 of in situ process 94. One or more simulations may be used to obtain additional or modified model parameters of in situ process 94. The additional or modified model parameters may be used to further assess in situ process 94.

In an embodiment, analysis 150 may include obtaining 152 additional information 118" about properties of in situ process 94. Properties may include, for example, thermal conductivity, heat capacity, porosity, or permeability of one or more portions of the formation. Properties may also include chemical reaction data such as chemical reactions, chemical components, and chemical reaction parameters. Properties may be obtained from the literature or from field or laboratory experiments. For example, properties of core samples of the treated formation may be measured in a laboratory. Additional information 118" may be used to operate in situ process 94. Alternatively, additional information 118" may be used in one or more simulations 90 to obtain additional information 118'. For example, additional information 118' may include one or more operating parameters that may be used to operate in situ process 94.

An in situ process for treating a formation may include treating a selected section of the formation with a minimum average overburden thickness. The minimum average overburden thickness may depend on a type of hydrocarbon resource and geological formation surrounding the hydrocarbon resource. An overburden may, in some embodiments, be substantially impermeable so that fluids produced in the selected section are inhibited from passing to the ground surface through the overburden. A minimum overburden thickness may be determined as the minimum overburden needed to inhibit the escape of fluids produced in the formation and to inhibit breakthrough to the surface due to increased pressure within the formation during in the situ conversion process. Minimum overburden thickness may be dependent on, for example, composition of the overburden, maximum pressure to be reached in the formation during the in situ conversion process, permeability of the overburden, composition of fluids produced in the formation, and/or temperatures in the formation or overburden. A ratio of overburden thickness to hydrocarbon resource thickness may be used during selection of resources to produce using an in situ thermal conversion process.

Selected factors may be used to determine a minimum overburden thickness. These selected factors may include overall thickness of the overburden, lithology and/or rock properties of the overburden, earth stresses, expected extent of subsidence and/or reservoir compaction, a pressure of a process to be used in the formation, and extent and connectivity of natural fracture systems surrounding the formation.

For coal, a minimum overburden thickness may be about 50 m or between about 25 m and 100 m. In some embodiments, a selected section may have a minimum overburden pressure. A minimum overburden to resource thickness may be between about 0.25:1 and 100:1.

For oil shale, a minimum overburden thickness may be about 100 m or between about 25 m and 300 m. A minimum overburden to resource thickness may be between about 0.25:1 and 100:1.

FIG. 19 illustrates a flow chart of a computer-implemented method for determining a selected overburden thickness. Selected section properties 154 may be input into computational system 156. Properties of the selected section may include type of formation, density, permeability, porosity, earth stresses, etc. Selected section properties 154 may be used by a software executable to determine minimum overburden thickness 158 for the selected section. The software executable may be, for example, ABAQUS. The software executable may incorporate selected factors. Computational system 156 may also run a simulation to determine minimum overburden thickness 158. The minimum overburden thickness may be determined so that fractures that allow formation fluid to pass to the ground surface will not form within the overburden during an in situ process. A formation may be selected for treatment by computational system 156 based on properties of the formation and/or properties of the overburden as determined herein. Overburden properties 160 may also be input into computational system 156. Properties of the overburden may include a type of material in the overburden, density of the overburden, permeability of the overburden, earth stresses, etc. Computational system 156 may also be used to determine operating conditions and/or control operating conditions for an in situ process of treating a formation.

Heating of the formation may be monitored during an in situ conversion process. Monitoring heating of a selected section may include continuously monitoring acoustical data associated with the selected section. Acoustical data may include seismic data or any acoustical data that may be measured, for example, using geophones, hydrophones, or other acoustical sensors. In an embodiment, a continuous acoustical monitoring system can be used to monitor (e.g., intermittently or constantly) the formation. The formation can be monitored (e.g., using geophones at 2 kilohertz, recording measurements every 1/8 of a millisecond) for undesirable formation conditions. In an embodiment, a continuous acoustical monitoring system may be obtained from Oyo Instruments (Houston, TX).

Acoustical data may be acquired by recording information using underground acoustical sensors located within and/or proximate a treated formation area. Acoustical data may be used to determine a type and/or location of fractures developing within the selected section. The fractures may be thermal fractures. The fractures may be vertical hydraulic fractures formed to initially increase permeability in a formation. Acoustical data may be input into a computational system to determine the type and/or location of fractures. Also, heating profiles of the formation or selected section may be determined by the computational system using the acoustical data. The computational system may run a software executable to process the acoustical data. The computational system may be used to determine a set of operating conditions for treating the formation in situ. The computational system may also be used to control the set of operating conditions for treating the formation in situ based on the acoustical data. Other properties, such as a temperature of the formation, may also be input into the computational system.

An in situ conversion process may be controlled by using some of the production wells as injection wells for injection of steam and/or other process modifying fluids (e.g., hydrogen, which may affect a product composition through in situ hydrogenation).

In certain embodiments, it may be possible to use well technologies that may operate at high temperatures. These technologies may include both sensors and control mechanisms. The heat injection profiles and hydrocarbon vapor production may be adjusted on a more discrete basis. It may be possible to adjust heat profiles and production on a bed-by-bed basis or in meter-by-meter increments. This may allow the in situ conversion process to compensate, for example, for different thermal properties and/or organic contents in an interbedded lithology. Thus, cold and hot spots may be inhibited from forming, the formation may not be overpressurized, and/or the integrity of the formation may not be highly stressed, which could cause deformations and/or damage to wellbore integrity.

FIGS. 20 and 21 illustrate schematic diagrams of a plan view and a cross-sectional representation, respectively, of a zone being treated using an in situ conversion process. The in situ conversion process may cause microseismic failures, or fractures, within the treatment zone from which a seismic wave may be emitted. Treatment zone 162 may be heated using heat provided from heater 164 placed in heater well 144. Pressure in treatment zone 162 may be controlled by producing some formation fluid through heater wells 144 and/or production wells. Heat from heater 164 may cause failure 166 in a portion of the formation proximate treatment zone 162. Failure 166 may be a localized rock failure within a rock volume of the formation. Failure 166 may be an instantaneous failure. Failure 166 tends to produce seismic disturbance 168. Seismic disturbance 168 may be an elastic or microseismic disturbance that propagates as a body wave in the formation surrounding the failure. Magnitude and direction of seismic disturbance as measured by sensors may indicate a type of macro-scale failure that occurs within the formation and/or treatment zone 162. For example, seismic disturbance 168 may be evaluated to indicate a location, orientation, and/or extent of one or more macro-scale failures that occurred in the formation due to heat treatment of the treatment zone 162.

Seismic disturbance 168 from one or more failures 166 may be detected with one or more sensors 122. Sensor 122 may be a geophone, hydrophone, accelerometer, and/or other seismic sensing device. Sensors 122 may be placed in monitoring well 170 or monitoring wells. Monitoring wells 170 may be placed in the formation proximate heater well 144 and treatment zone 162. In certain embodiments, three monitoring wells 170 are placed in the formation such that a location of failure 166 may be triangulated using sensors 122 in each monitoring well.

In an in situ conversion process embodiment, sensors 122 may measure a signal of seismic disturbance 168. The signal may include a wave or set of waves emitted from failure 166. The signals may be used to determine an approximate location of failure 166. An approximate time at which failure 166 occurred, causing seismic disturbance 168, may also be determined from the signal. This approximate location and approximate time of failure 166 may be used to determine if failure 166 can propagate into an undesired zone of the formation. The undesired zone may include a water aquifer, a zone of the formation undesired for treatment, overburden 60 of the formation, and/or underburden 172 of the formation. An aquifer may also lie above overburden 60 or below underburden 172. Overburden 60 and/or underburden 172 may include one or more rock layers that can be fractured and allow formation fluid to undesirably escape from the in situ conversion process. Sensors 122 may be used to monitor a progression of failure 166 (i.e., an increase in extent of the failure) over a period of time.

In certain embodiments, a location of failure 166 may be more precisely determined using a vertical distribution of sensors 122 along each monitoring well 170. The vertical distribution of sensors 122 may include at least one sensor above overburden 60 and/or below underburden 172. The sensors above overburden 60 and/or below underburden 172 may be used to monitor penetration (or an absence of penetration) of a failure through the overburden or underburden.

If failure 166 propagates into an undesired zone of the formation, a parameter for treatment of treatment zone 162 controlled through heater well 144 may be altered to inhibit propagation of the failure. The parameter of treatment may include a pressure in treatment zone 162, a volume (or flow rate) of fluids injected into the treatment zone or removed from the treatment zone, or a heat input rate from heater 164 into the treatment zone.

FIG. 22 illustrates a flow chart of an embodiment of a method used to monitor treatment of a formation. Treatment plan 174 may be provided for a treatment zone (e.g., treatment zone 162 in FIGS. 20 and 21). Parameters 176 for treatment plan 174 may include, but are not limited to, pressure in the treatment zone, heating rate of the treatment zone, and average temperature in the treatment zone. Treatment parameters 176 may be controlled to treat through heat sources, production wells, and/or injection wells. A failure or failures may occur during treatment of the treatment zone for a given set of parameters. Seismic disturbances that indicate a failure may be detected by sensors placed in one or more monitoring wells in monitoring step 178. The seismic disturbances may be used to determine a location, a time, and/or extent of the one or more failures in determination step 180. Determination step 180 may include imaging the seismic disturbances to determine a spatial location of a failure or failures and/or a time at which the failure or failures occurred. The location, time, and/or extent of the failure or failures may be processed to determine if treatment parameters 176 can be altered to inhibit the propagation of a failure or failures into an undesired zone of the formation in interpretation step 184.

In an in situ conversion process embodiment, a recording system may be used to continuously monitor signals from sensors placed in a formation. The recording system may continuously record the signals from sensors. The recording system may save the signals as data. The data may be permanently saved by the recording system. The recording system may simultaneously monitor signals from sensors. The signals may be monitored at a selected sampling rate (e.g., about once every 0.25 milliseconds). In some embodiments, two recording systems may be used to continuously monitor signals from sensors. A recording system may be used to record each signal from the sensors at the selected sampling rate for a desired time period. A controller may be used when the recording system is used to monitor a signal. The controller may be a computational system or computer. In an embodiment using two or more recording systems, the controller may direct which recording system is used for a selected time period. The controller may include a global positioning satellite (GPS) clock. The GPS clock may be used to provide a specific time for a recording system to begin monitoring signals (e.g., a trigger time) and a time period for the monitoring of signals. The controller may provide the specific time for the recording system to begin monitoring signals to a trigger box. The trigger box may be used to supply a trigger pulse to a recording system to begin monitoring signals.

A storage device may be used to record signals monitored by a recording system. The storage device may include a tape drive (e.g., a high-speed, high-capacity tape drive) or any device capable of recording relatively large amounts of data at very short time intervals. In an embodiment using two recording systems, the storage device may receive data from the first recording system while the second recording system is monitoring signals from one or more sensors, or vice versa. This enables continuous data coverage so that all or substantially all microseismic events that occur will be detected. In some embodiments, heat progression through the formation may be monitored by measuring microseismic events caused by heating of various portions of the formation.

FIG. 23 illustrates a schematic of an embodiment used to control an in situ conversion process in formation 182. Barrier well 50, monitoring well 170, production well 44, and heater well 144 may be placed in formation 182. Barrier well 50 may be used to control water conditions within formation 182. Monitoring well 170 may be used to monitor subsurface conditions in the formation, such as, but not limited to, pressure, temperature, product quality, or fracture progression. Production well 44 may be used to produce formation fluids (e.g., oil, gas, and water) from the formation. Heater well 144 may be used to provide heat to the formation. Formation conditions such as, but not limited to, pressure, temperature, fracture progression (monitored, for instance, by acoustical sensor data), and fluid quality (e.g., product quality or water quality) may be monitored through one or more of wells 50, 170, 44, and 144.

Surface data such as pump status (e.g., pump on or off), fluid flow rate, surface pressure/temperature, and heater power may be monitored by instruments placed at each well or certain wells. Similarly, subsurface data such as pressure, temperature, fluid quality, and acoustical sensor data may be monitored by instruments placed at each well or certain wells. Surface data 186 from barrier well 50 may include pump status, flow rate, and surface pressure/temperature. Surface data 188 from production well 44 may include pump status, flow rate, and surface pressure/temperature. Subsurface data 190 from barrier well 50 may include pressure, temperature, water quality, and acoustical sensor data. Subsurface data 192 from monitoring well 170 may include pressure, temperature, product quality, and acoustical sensor data. Subsurface data 194 from production well 44 may include pressure, temperature, product quality, and acoustical sensor data. Subsurface data 196 from heater well 144 may include pressure, temperature, and acoustical sensor data.

Surface data 186 and 188 and subsurface data 190, 192, 194, and 196 may be monitored as analog data 198 from one or more measuring instruments. Analog data 198 may be converted to digital data 200 in analog-to-digital converter 202. Digital data 200 may be provided to computational system 156. Alternatively, one or more measuring instruments may provide digital data to computational system 156. Computational system 156 may include a distributed central processing unit (CPU). Computational system 156 may process digital data 200 to interpret analog data 198. Output from computational system 156 may be provided to remote display 204, data storage 140, display 138, or to surface facility 142. Surface facility 142 may include, for example, a hydrotreating plant, a liquid processing plant, or a gas processing plant. Computational system 156 may provide digital output 206 to digital-to-analog converter 208. Digital-to-analog converter 208 may convert digital output 206 to analog output 210.

Analog output 210 may include instructions to control one or more conditions of formation 182. Analog output 210 may include instructions to control the in situ conversion process within formation 182. Analog output 210 may include instructions to adjust one or more parameters of the in situ conversion process. The one or more parameters may include, but are not limited to, pressure, temperature, product composition, and product quality. Analog output 210 may include instructions for control of pump status 212 or flow rate 214 at barrier well 50. Analog output 210 may include instructions for control of pump status 212 or flow rate 214 at production well 44. Analog output 210 may also include instructions for control of heater power 216 at heater well 144. Analog output

210 may include instructions to vary one or more conditions such as pump status, flow rate, or heater power. Analog output 210 may also include instructions to turn on and/or off pumps, heaters, or monitoring instruments located at each well.

Remote input data 218 may also be provided to computational system 156 to control conditions within formation 182. Remote input data 218 may include data used to adjust conditions of formation 182. Remote input data 218 may include data such as, but not limited to, electricity cost, gas or oil prices, pipeline tariffs, data from simulations, plant emissions, or refinery availability. Remote input data 218 may be used by computational system 156 to adjust digital output 206 to a desired value. In some embodiments, surface facility data 220 may be provided to computational system 156.

An in situ conversion process may be monitored using a feedback control process. Conditions within a formation may be monitored and used within the feedback control process. A formation being treated using an in situ conversion process may undergo changes in mechanical properties due to the conversion of solids and viscous liquids to vapors, fracture propagation (e.g., to overburden, underburden, water tables, etc.), increases in permeability or porosity and decreases in density, moisture evaporation, and/or thermal instability of matrix minerals (leading to dehydration and decarbonation reactions and shifts in stable mineral assemblages).

Remote monitoring techniques that will sense these changes in reservoir properties may include, but are not limited to, 4D (4 dimension) time lapse seismic monitoring, 3D/3C (3 dimension/3 component) seismic passive acoustic monitoring of fracturing, time lapse 3D seismic passive acoustic monitoring of fracturing, electrical resistivity, thermal mapping, surface or downhole tilt meters, surveying permanent surface monuments, chemical sniffing or laser sensors for surface gas abundance, and gravimetrics. More direct subsurface-based monitoring techniques may include high temperature downhole instrumentation (such as thermocouples and other temperature sensing mechanisms, pressure sensors such as hydrophones, stress sensors, or instrumentation in the producer well to detect gas flows on a finely incremental basis). In certain embodiments, a "base" seismic monitoring may be conducted, and then subsequent seismic results can be compared to determine changes.

U.S. Patent Nos. 6,456,566 issued to Aronstam; 5,418,335 issued to Winbow; and 4,879,696 issued to Kostelnicek et al. and U.S. Statutory Invention Registration H1561 to Thompson describe seismic sources for use in active acoustic monitoring of subsurface geophysical phenomena. A time-lapse profile may be generated to monitor temporal and areal changes in a hydrocarbon containing formation. In some embodiments, active acoustic monitoring may be used to obtain baseline geological information before treatment of a formation. During treatment of a formation, active and/or passive acoustic monitoring may be used to monitor changes within the formation.

Further modifications and alternative embodiments of various aspects of the invention may be apparent to those skilled in the art in view of this description. Accordingly, this description is to be construed as illustrative only and is for the purpose of teaching those skilled in the art the general manner of carrying out the invention. It is to be understood that the forms of the invention shown and described herein are to be taken as the presently preferred embodiments. Elements and materials may be substituted for those illustrated and described herein, parts and processes may be reversed, and certain features of the invention may be utilized independently, all as would be apparent to one skilled in the art after having the benefit of this description of the invention. Changes may be made in the elements described herein without departing from the spirit and scope of the invention as described in the following claims. In addition, it is to be understood that features described herein independently may, in certain embodiments, be combined.

WHAT IS CLAIMED IS:

1. A method for controlling an in situ system of heating a hydrocarbon containing formation with heaters, comprising:

monitoring at least one acoustic event within the formation using at least one acoustic detector;

analyzing at least one acoustic event to determine at least one property of the formation; and

controlling the in situ system based on the analysis of at least one acoustic event.

2. The method of claim 1, wherein at least one acoustic event is generated by an acoustic source.

3. The method of claim 1 or 2, wherein the method is continuously operated.

4. The method of any of claims 1-3, further comprising placing at least one acoustic detector within a wellbore in the formation and/or on a surface of the formation.

5. The method of any one of claims 1-4, further comprising recording at least one acoustic event with an acoustic monitoring system.

6. The method of any one of claims 1-5, further comprising pyrolyzing at least some hydrocarbons and/or generating synthesis gas within at least a portion of the formation.

7. The method of any one of claims 1-6, wherein analyzing at least one acoustic event comprises interpreting the at least one acoustic event.

8. The method of any one of claims 1-7, further comprising monitoring at least one acoustic event at a sampling rate of about at least once every 0.25 milliseconds.

9. The method of any one of claims 1-8, further comprising monitoring more than one acoustic event simultaneously with the acoustic monitoring system.

10. The method of any one of claims 1-9, wherein at least one property of the formation comprises an orientation of at least one fracture in the formation, a location of at least one fracture in the formation, and/or an extent of at least one fracture in the formation.

11. The method of any one of claims 1-10, wherein controlling the in situ system comprises modifying a temperature and/or a pressure of the in situ system.

12. The method of any one of claims 1-11, wherein the acoustic monitoring system comprises a seismic monitoring system.

13. The method of any one of claims 1-12, wherein at least one acoustic event comprises a seismic event.

14. The method of any one of claims 1-13, wherein at least one acoustic detector comprises a geophone or a hydrophone.

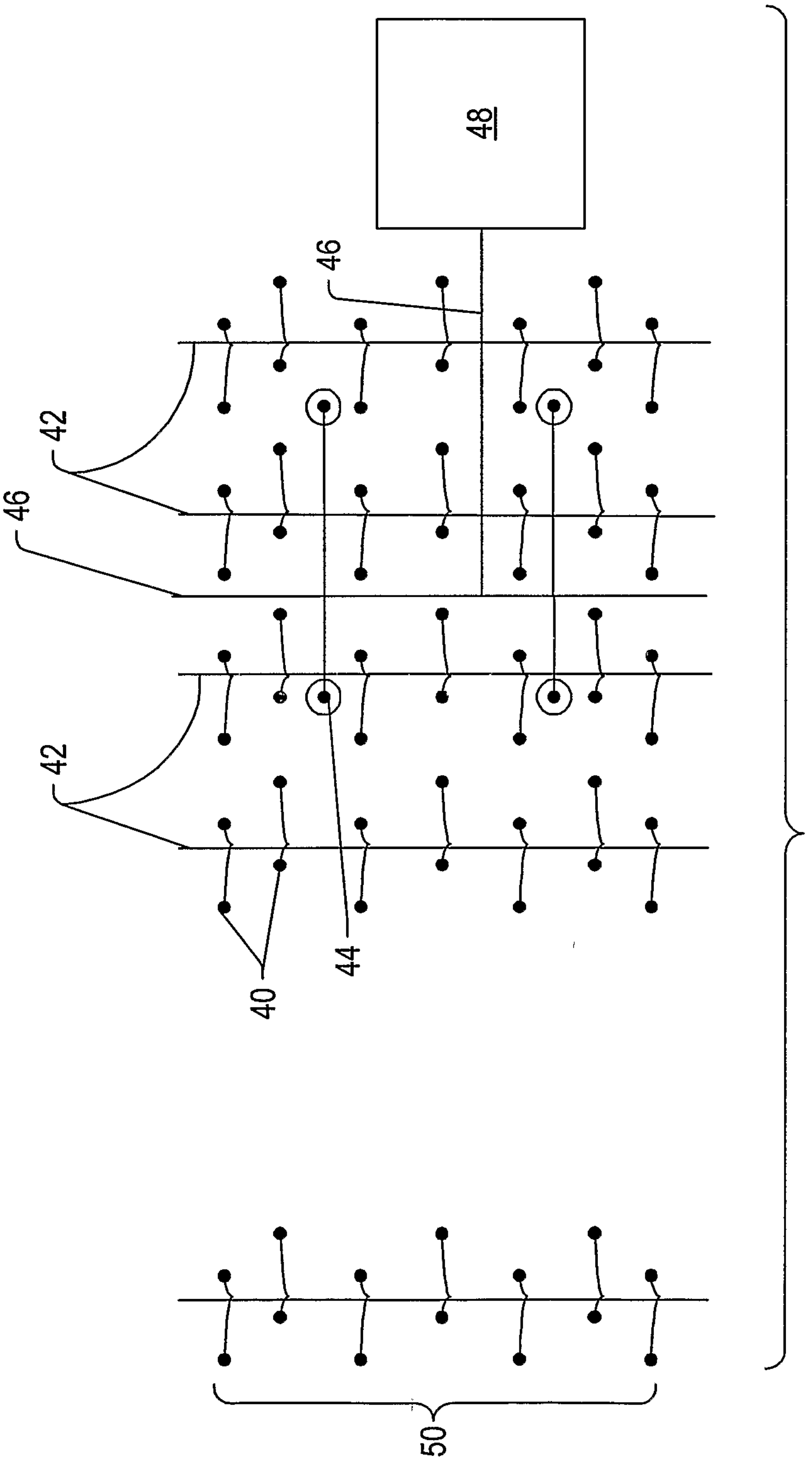


FIG. 1

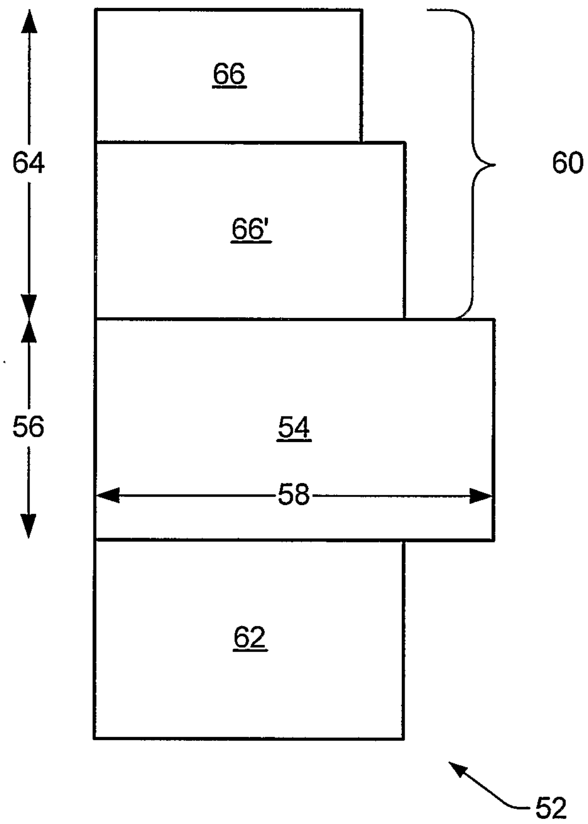


FIG. 2

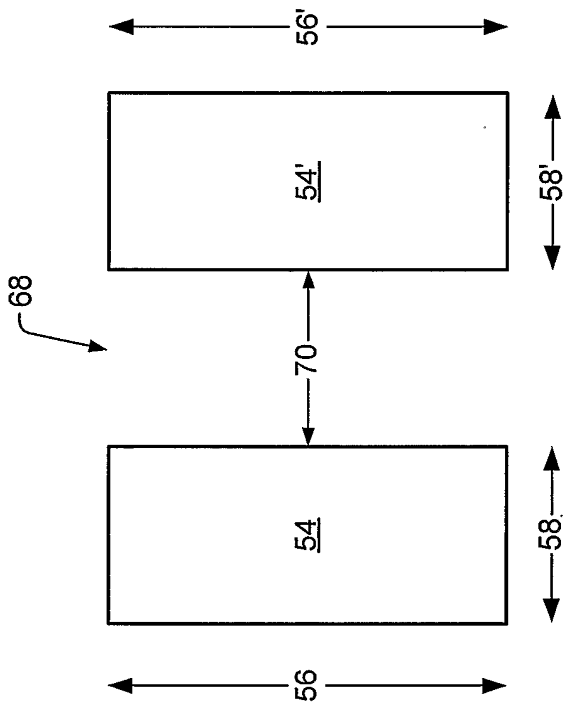


FIG. 3

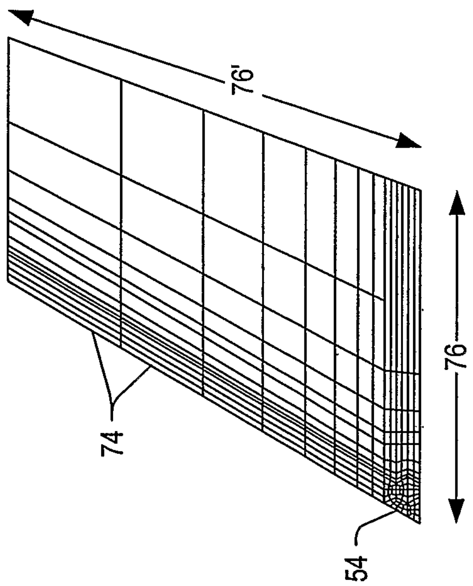


FIG. 5

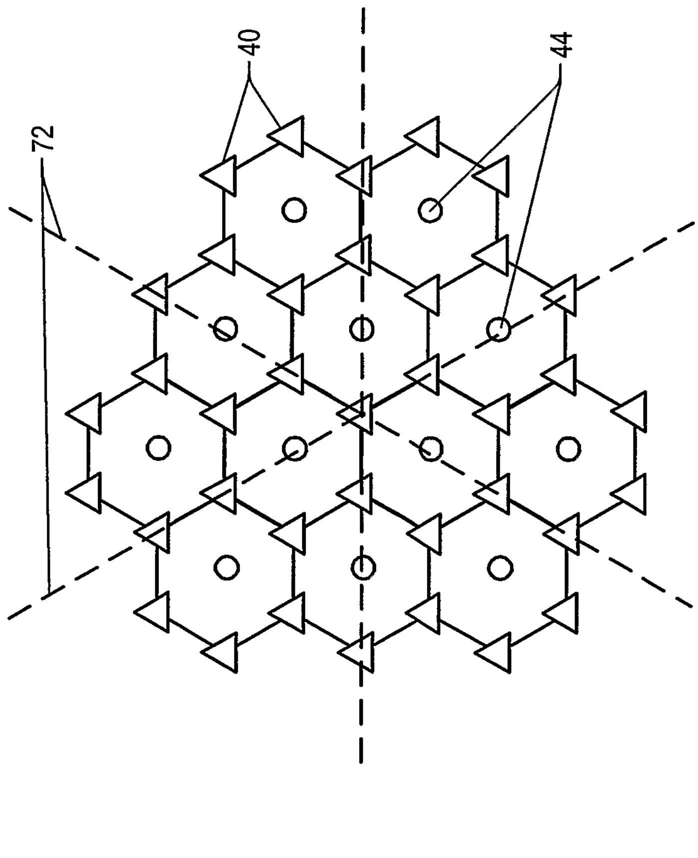


FIG. 4

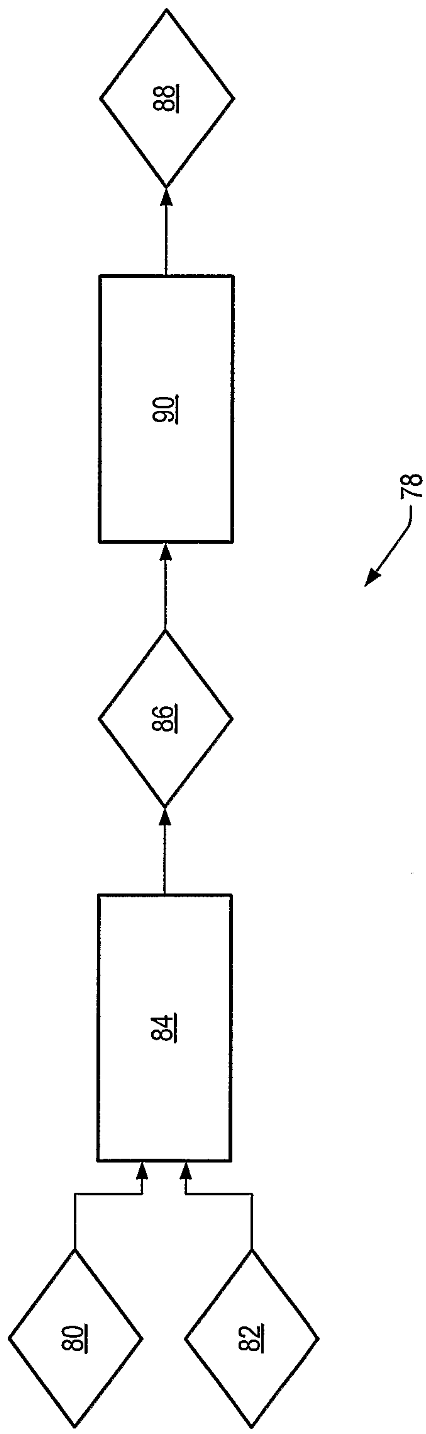


FIG. 6

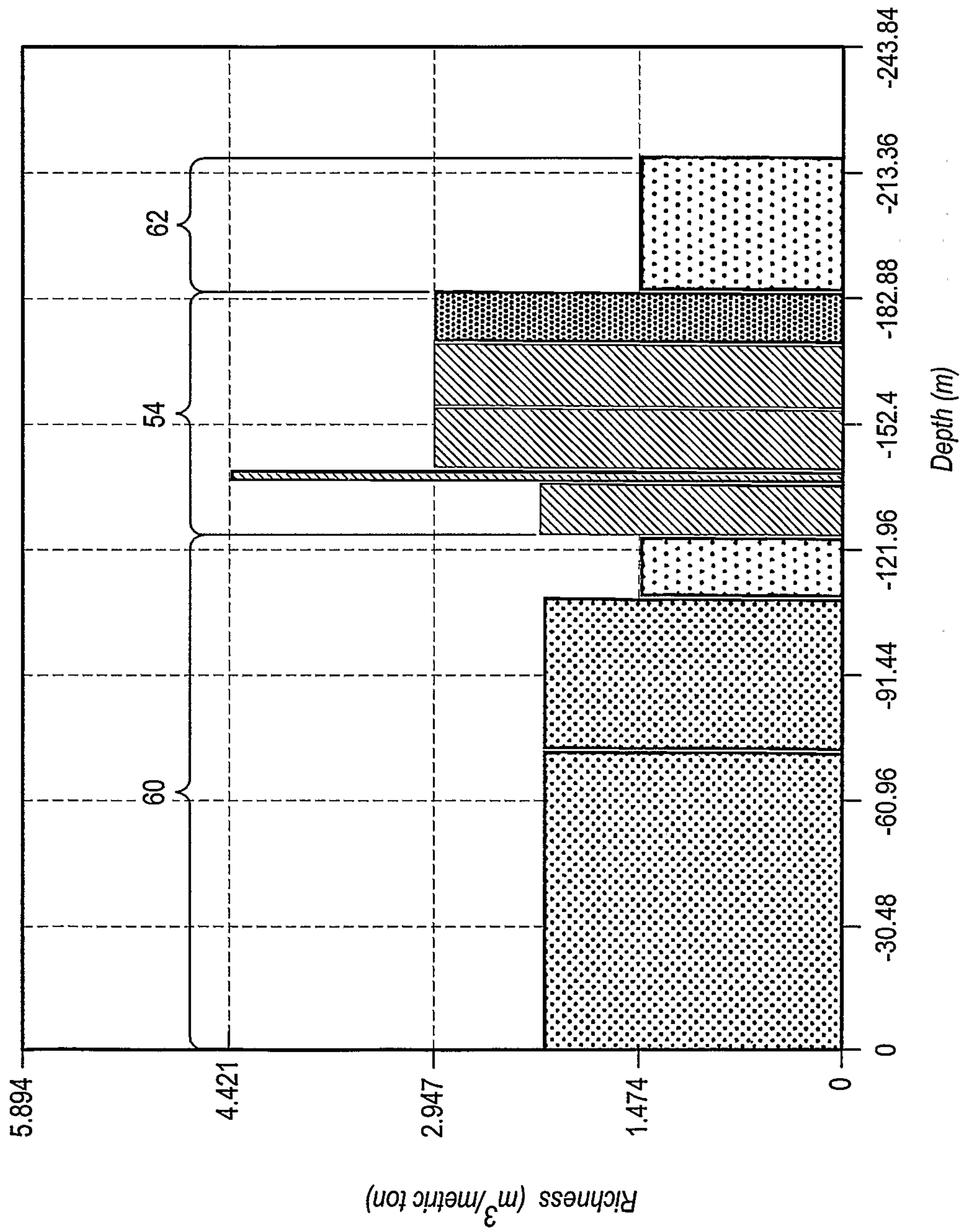

62
54
60
5.894
4.421
2.947
1.474
0
Richness (m^3/metric ton)
0
-30.48
-60.96
-91.44
-121.96
-152.4
-182.88
-213.36
-243.84
Depth (m)

FIG. 7

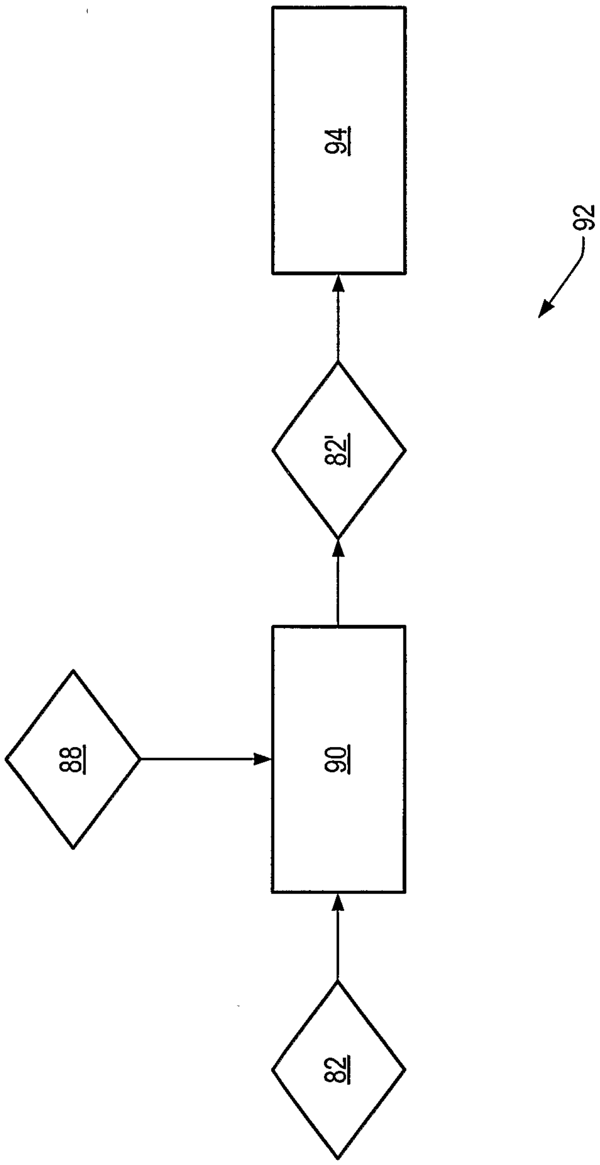


FIG. 8

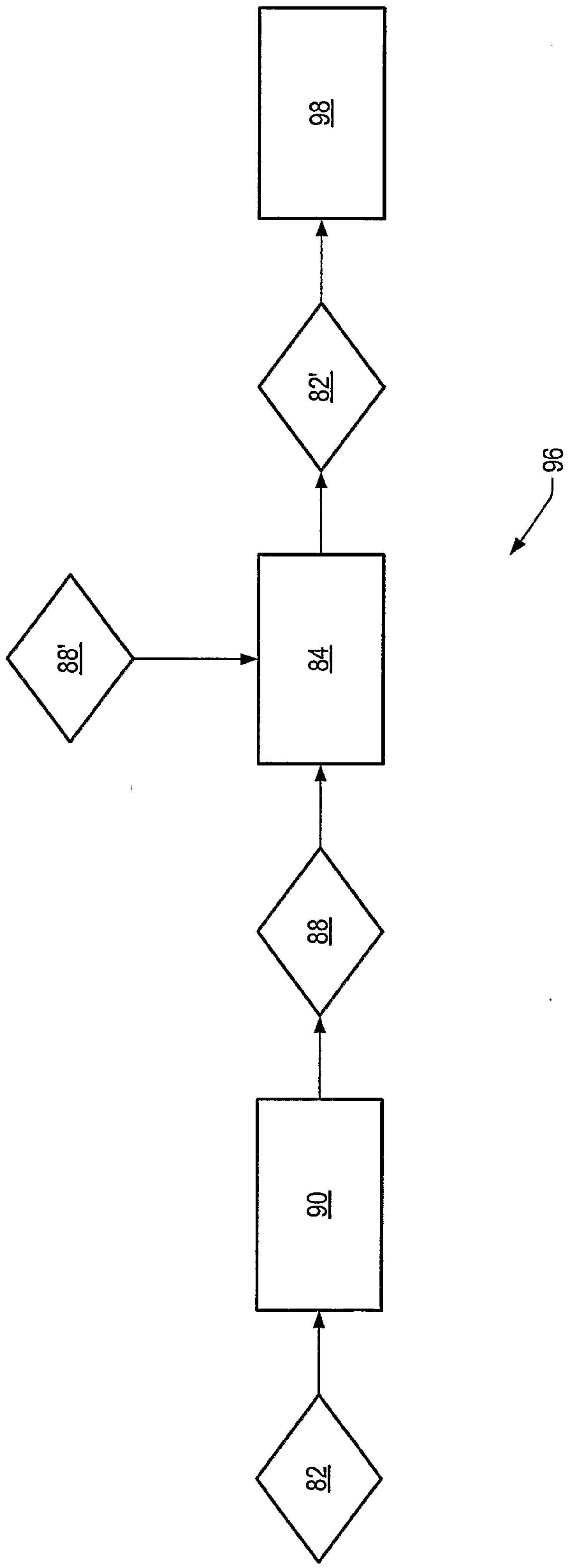


FIG. 9

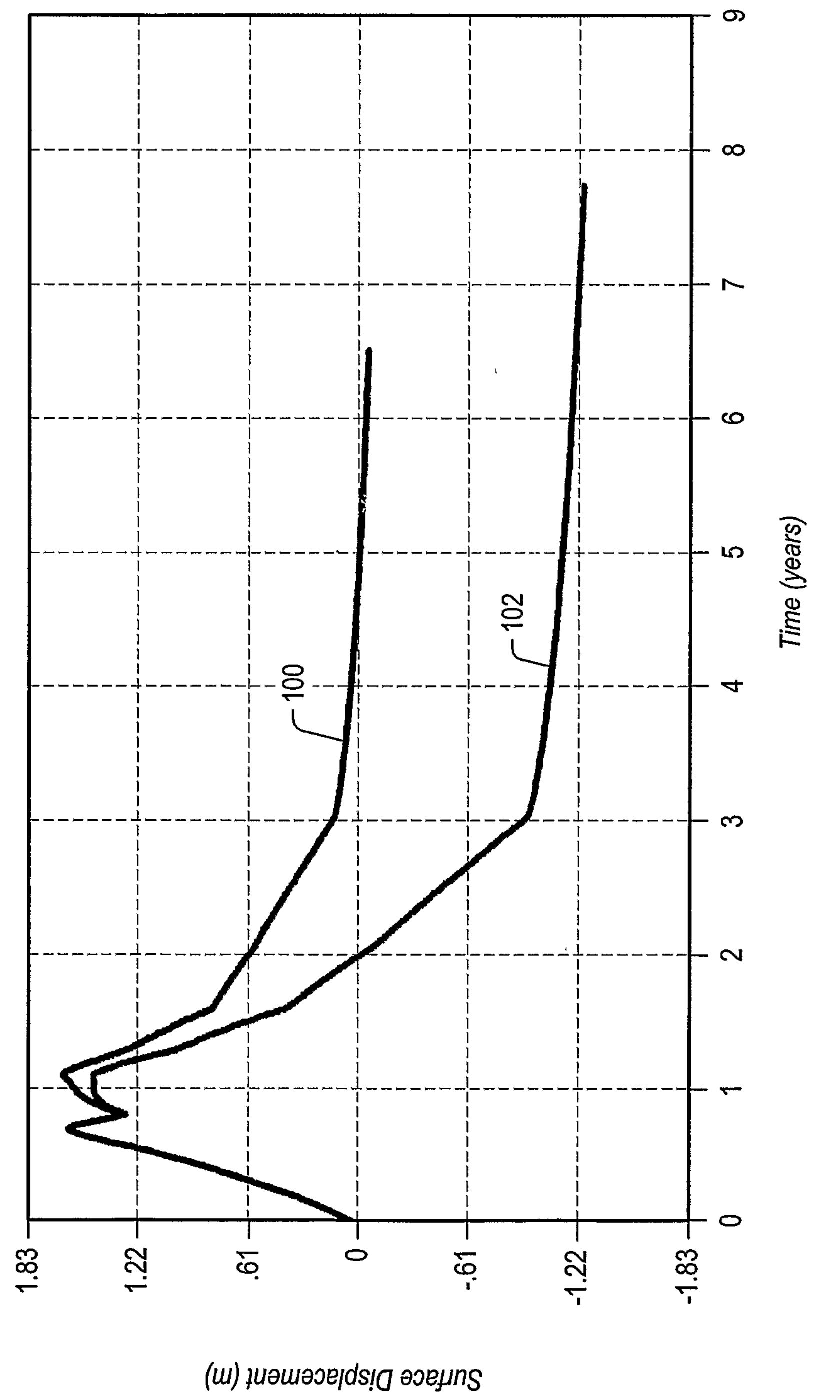

1.83
1.22
.61
0
-.61
-1.22
-1.83
Surface Displacement (m)
0
1
2
3
4
5
6
7
8
9
Time (years)
100
102

FIG. 10

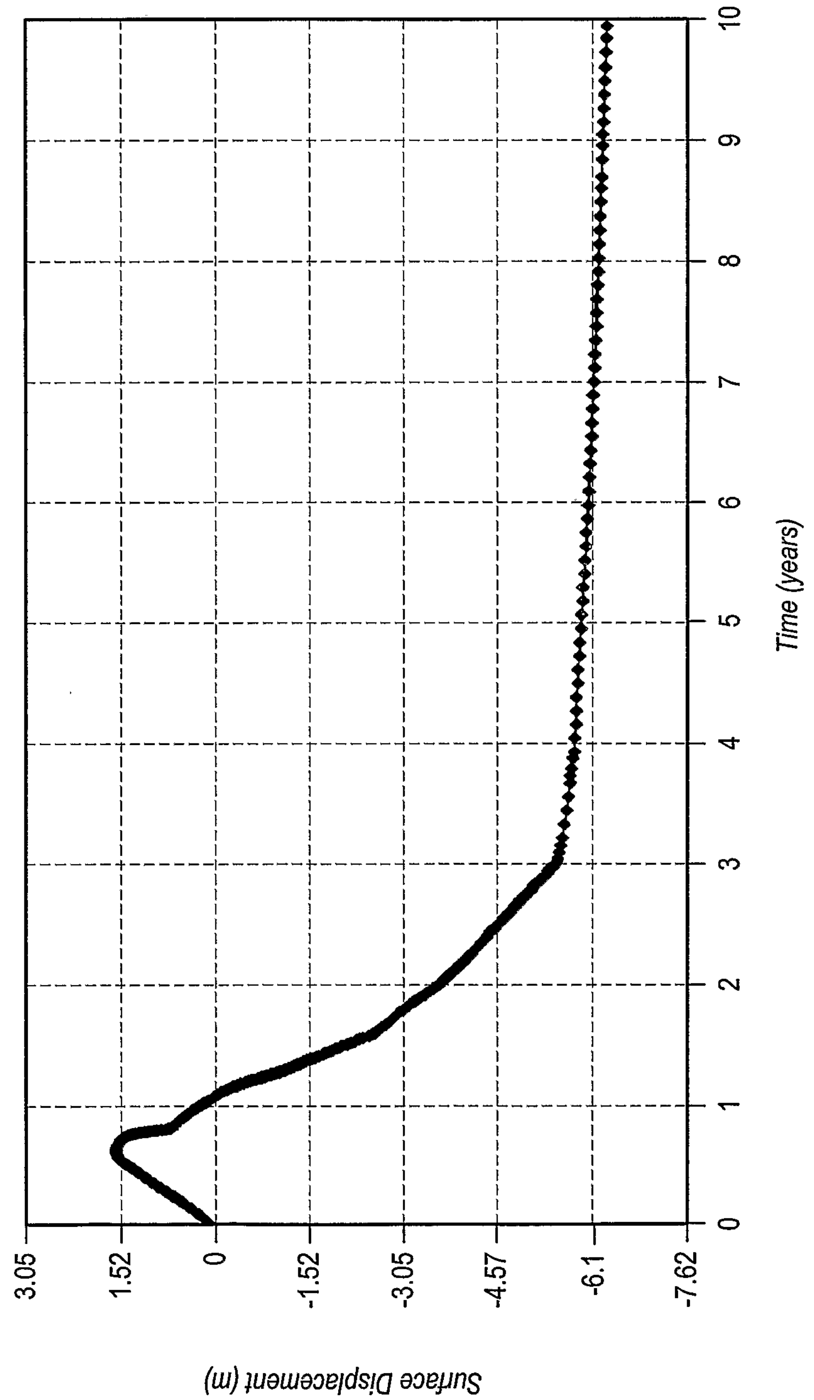

Surface Displacement (m)
3.05
1.52
0
-1.52
-3.05
-4.57
-6.1
-7.62
Time (years)
0
1
2
3
4
5
6
7
8
9
10

FIG. 11

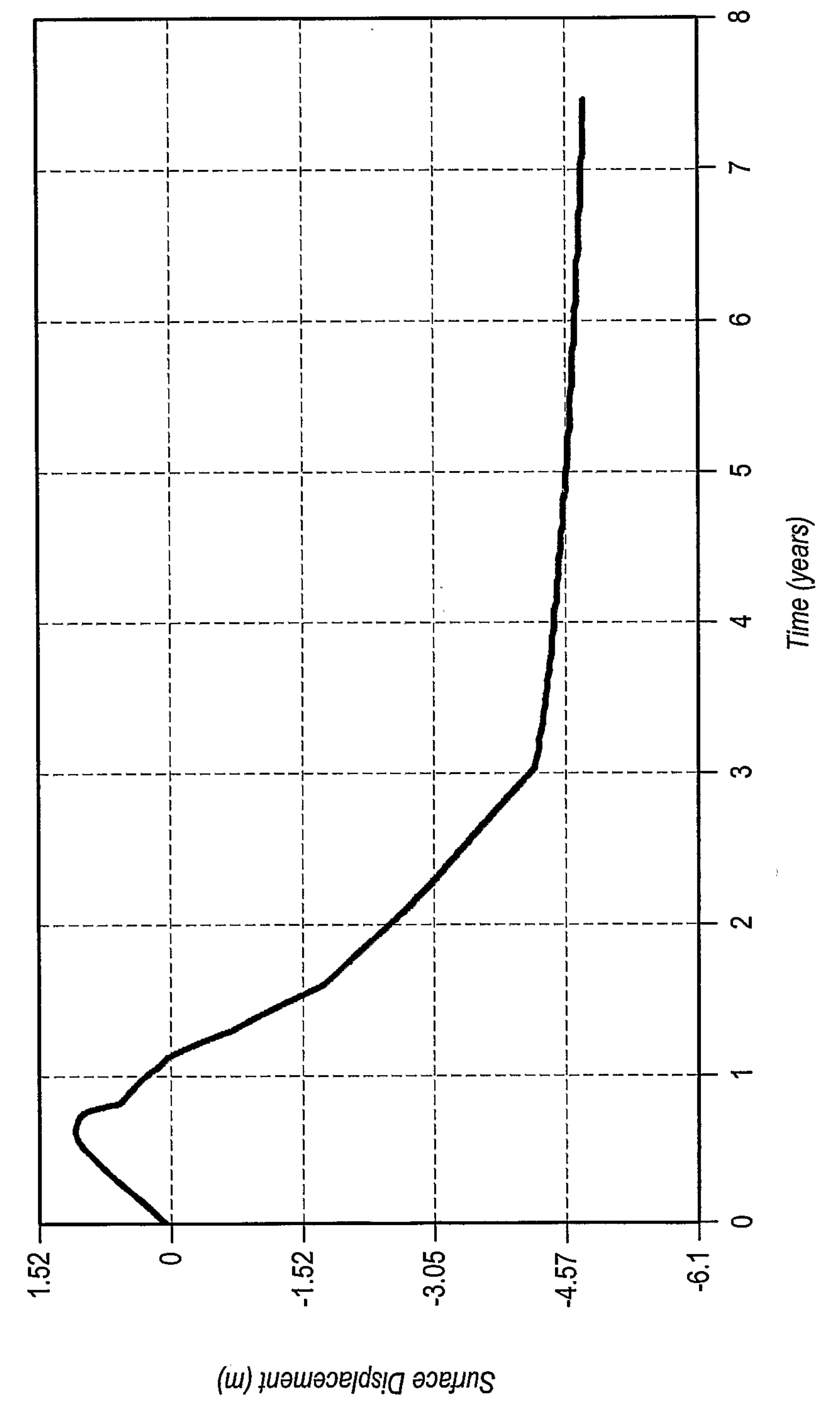

Surface Displacement (m)
1.52
0
-1.52
-3.05
-4.57
-6.1
Time (years)
0
1
2
3
4
5
6
7
8

FIG. 12

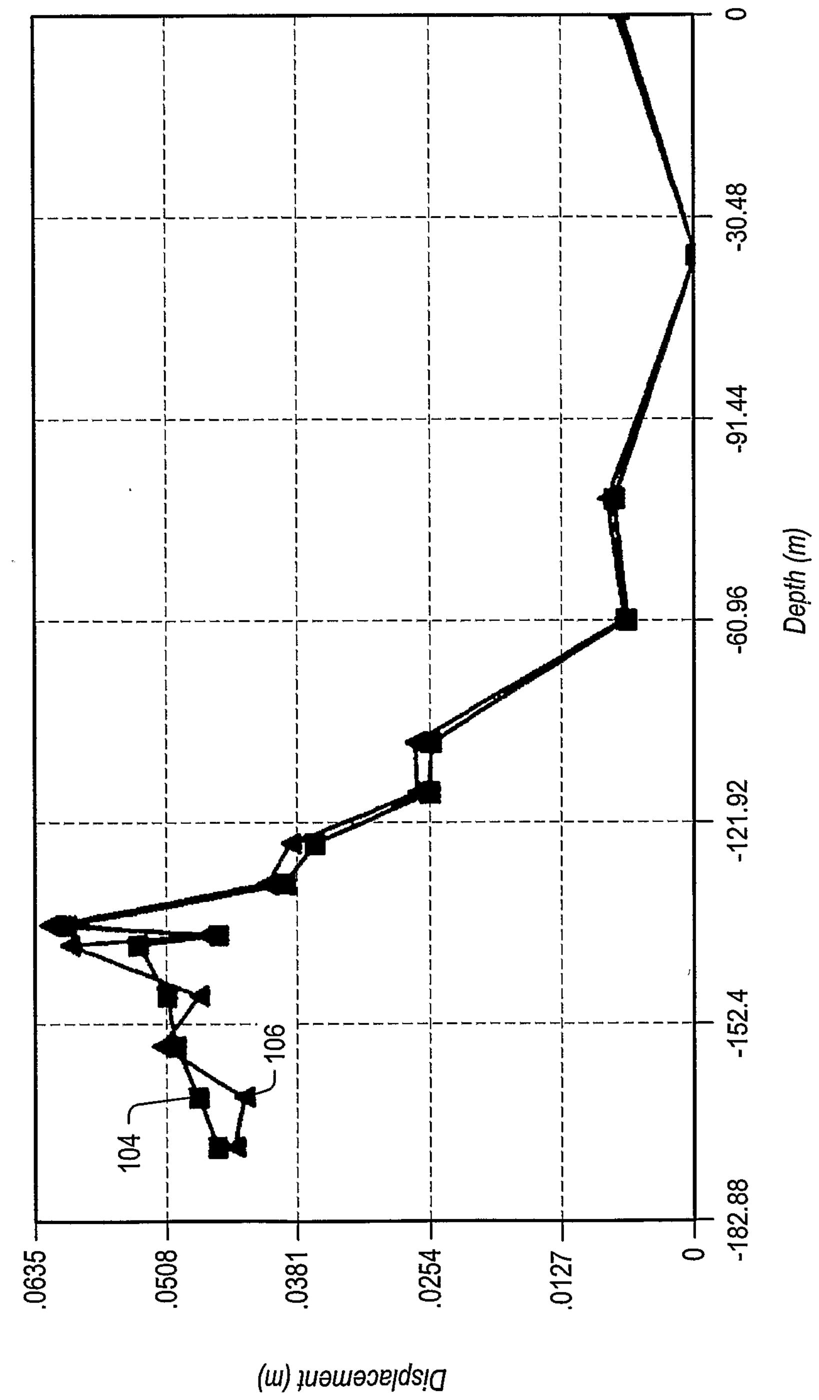

Displacement (m)
.0635
.0508
.0381
.0254
.0127
0
Depth (m)
0
-30.48
-91.44
-60.96
-121.92
-152.4
-182.88
104
106

FIG. 13

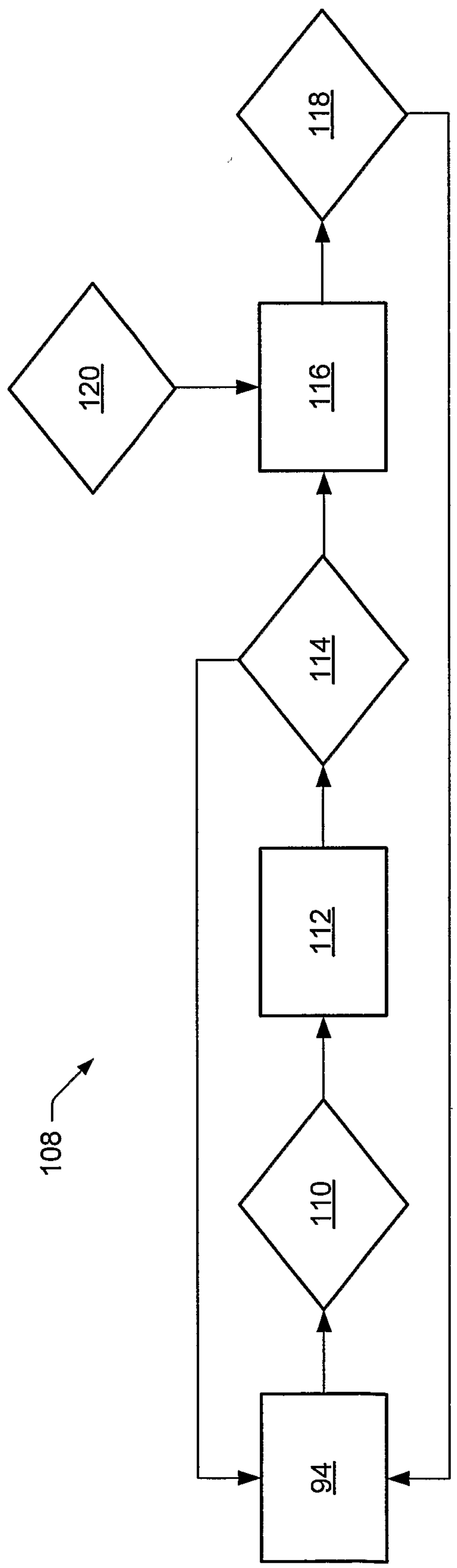


FIG. 14

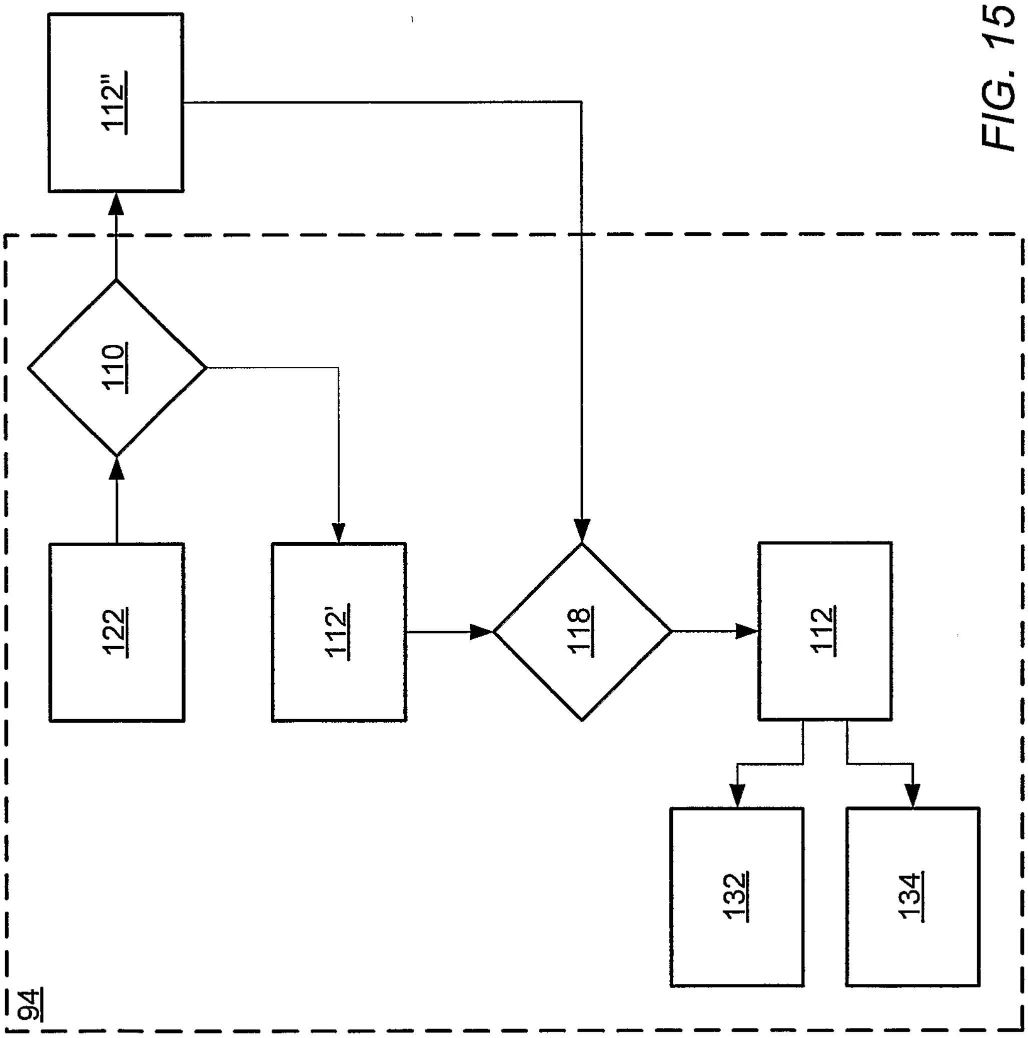


FIG. 15

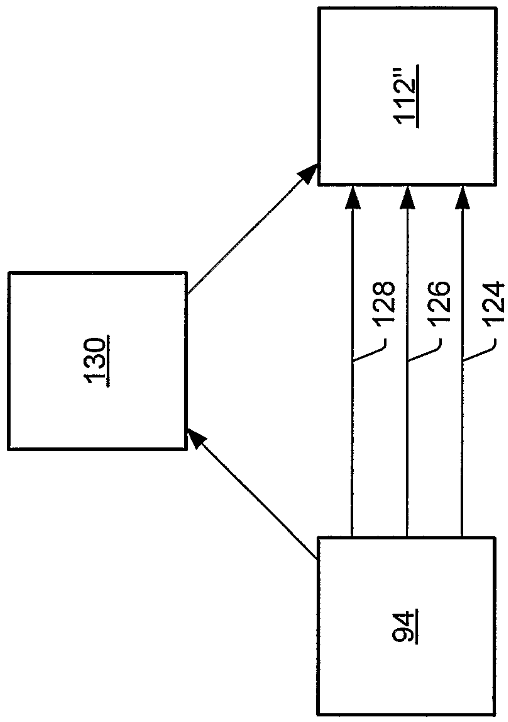


FIG. 16

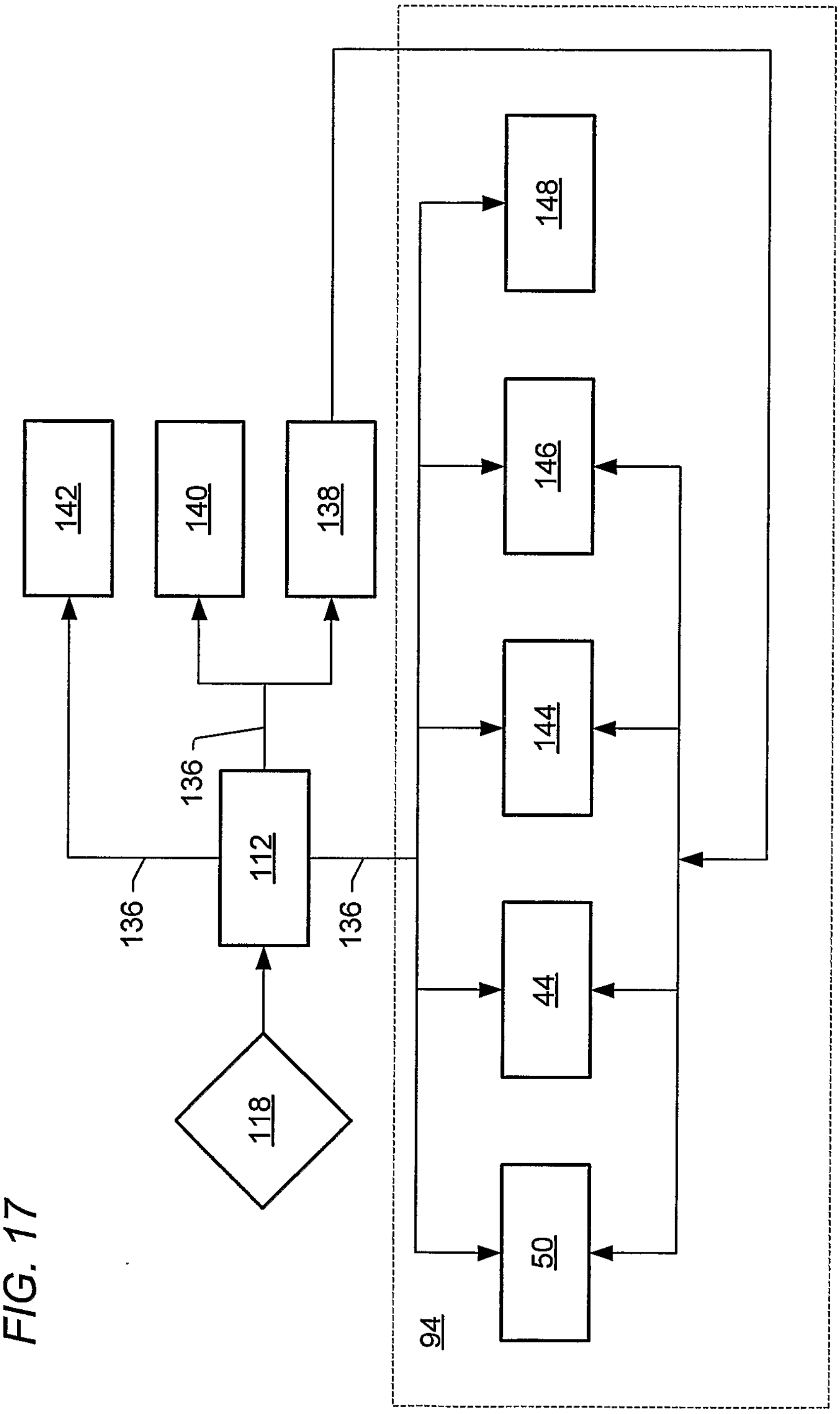


FIG. 17

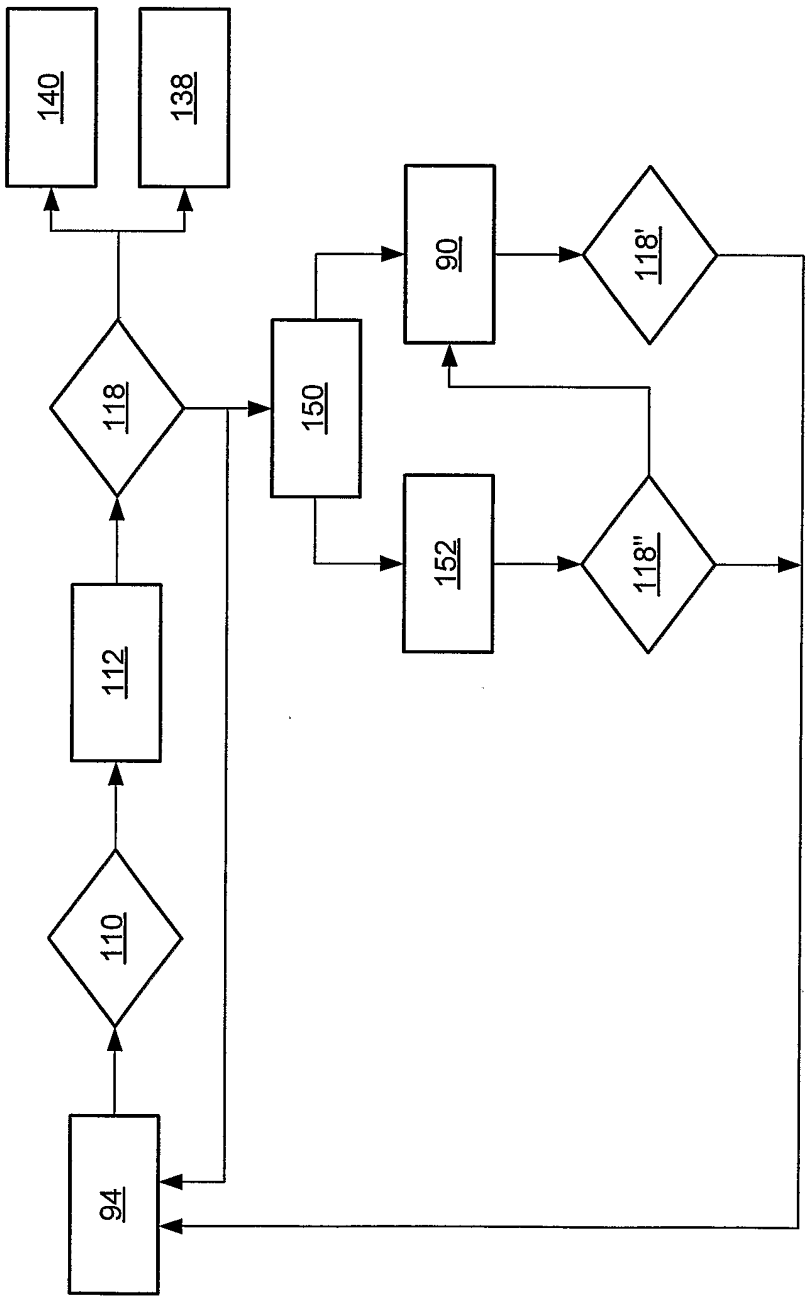


FIG. 18

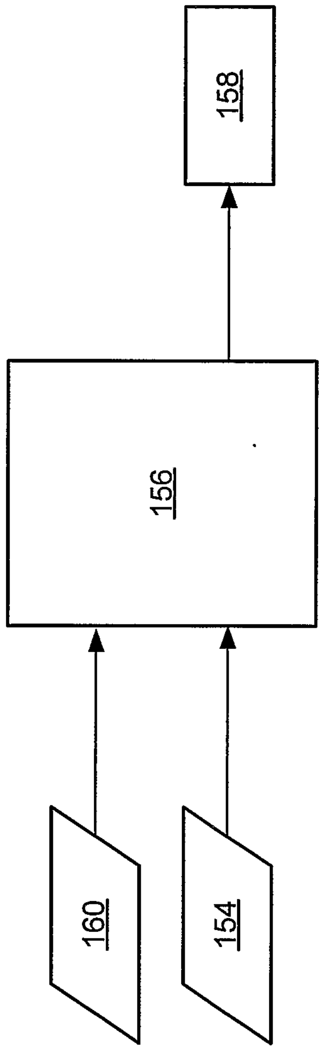


FIG. 19

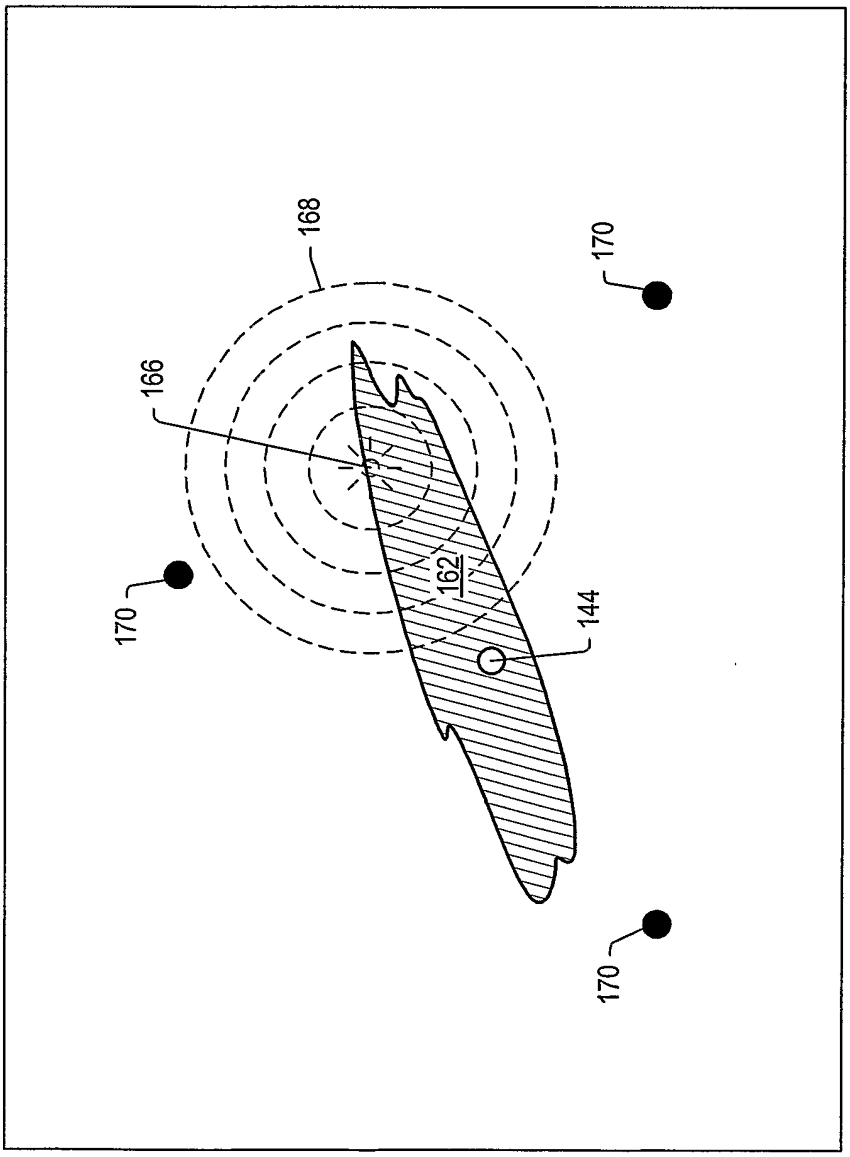


FIG. 20

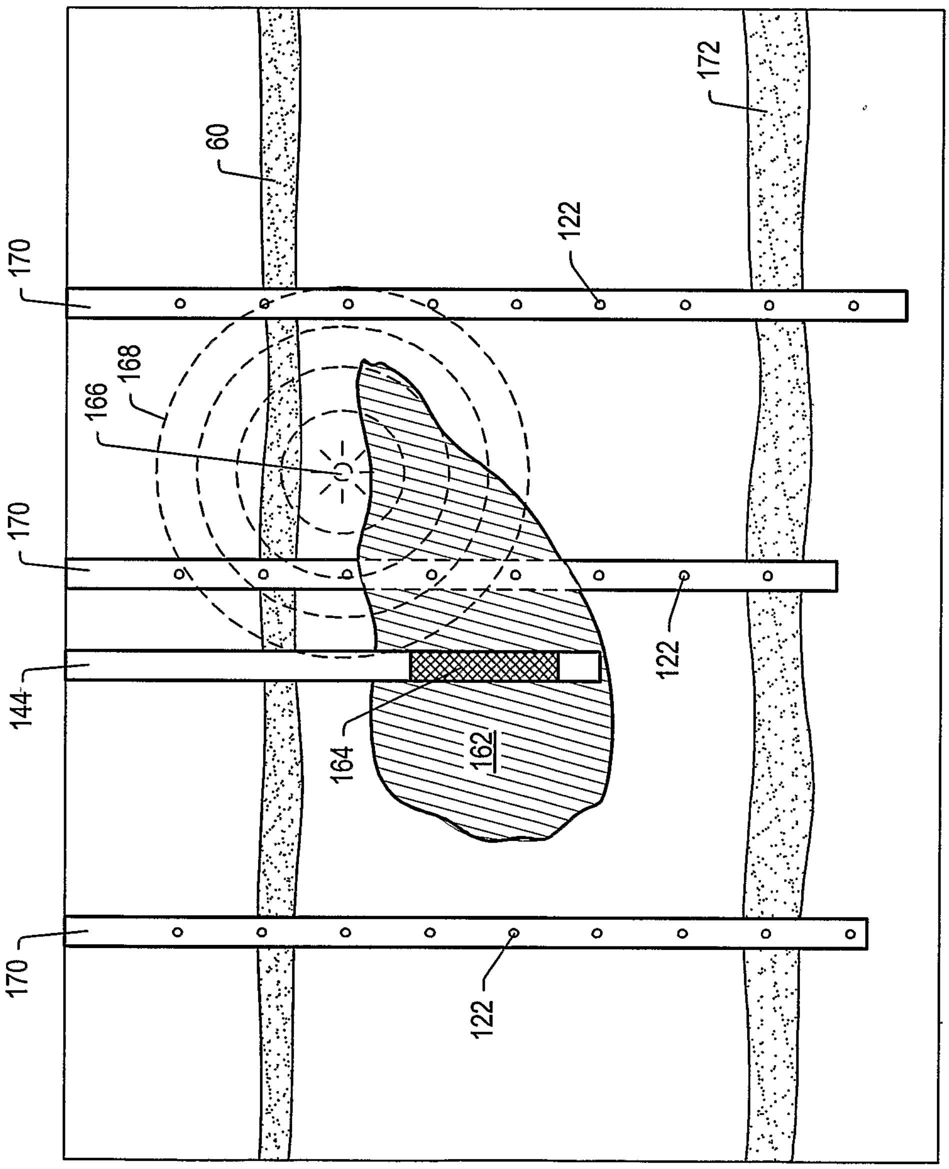


FIG. 21

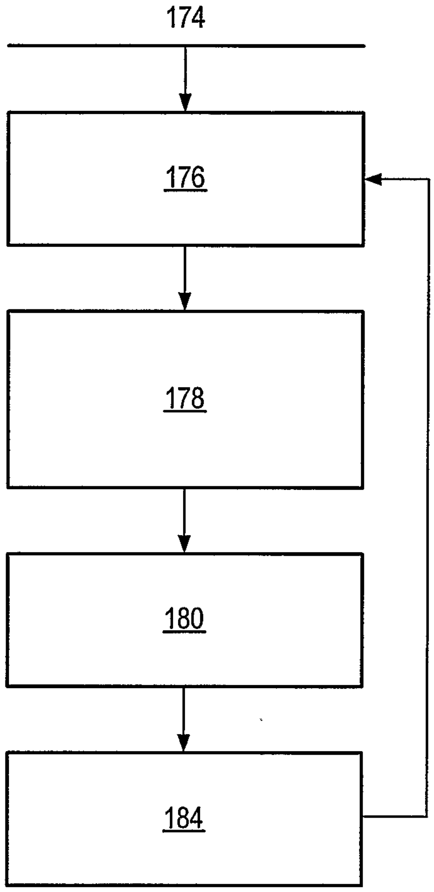
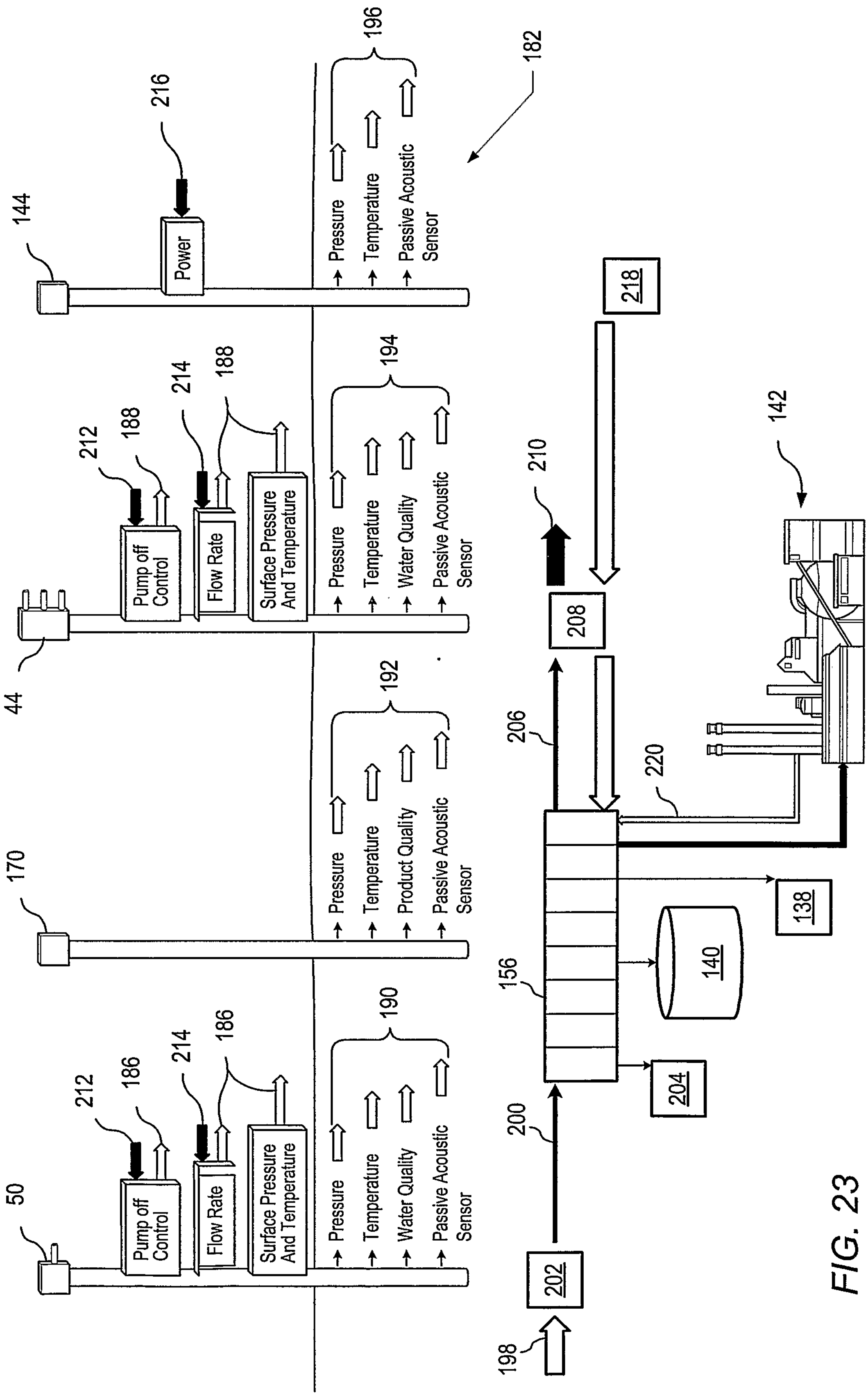


FIG. 22



50
186
212
214
186
Pump off Control
Flow Rate
Surface Pressure And Temperature
Pressure
Temperature
Water Quality
Passive Acoustic Sensor
190
170
Pressure
Temperature
Product Quality
Passive Acoustic Sensor
192
44
212
188
214
188
Pump off Control
Flow Rate
Surface Pressure And Temperature
Pressure
Temperature
Water Quality
Passive Acoustic Sensor
194
144
216
Power
Pressure
Temperature
Passive Acoustic Sensor
196
182
198
202
200
204
156
140
138
206
220
208
210
218
142

FIG. 23