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Sharma(10) **Pub. No.: US 2016/0003020 A1**(43) **Pub. Date: Jan. 7, 2016**(54) **METHODS FOR TIME-DELAYED
FRACTURING IN HYDROCARBON
FORMATIONS****Publication Classification**(71) Applicant: **BOARD OF REGENTS, THE
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Austin, TX (US)(72) Inventor: **Mukul M. Sharma, Austin, TX (US)**(21) Appl. No.: **14/765,613**(22) PCT Filed: **Feb. 4, 2014**(86) PCT No.: **PCT/US2014/014663**

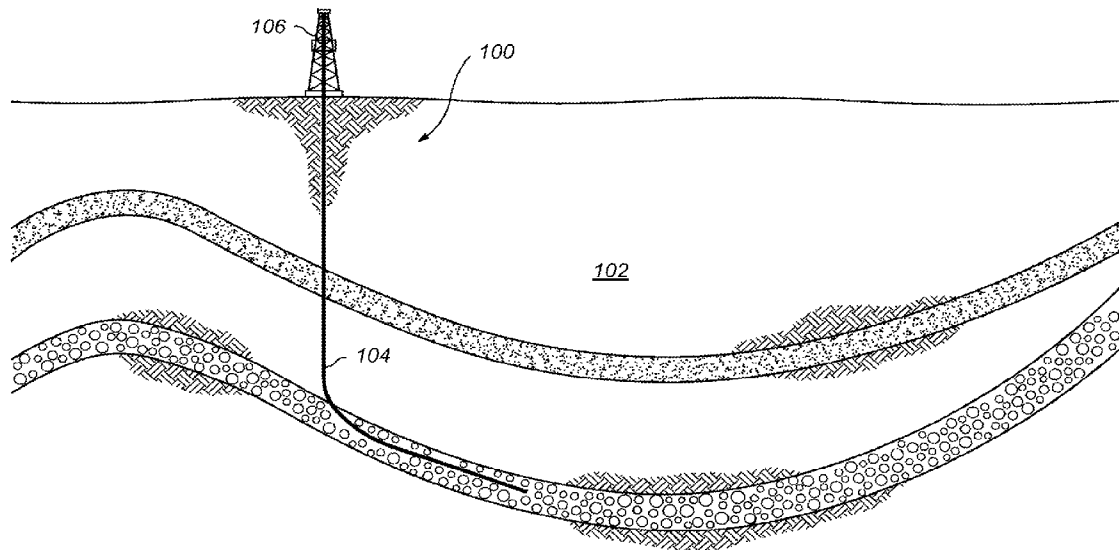
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4, 2013.(51) **Int. Cl.****E21B 43/26** (2006.01)**E21B 47/06** (2006.01)**E21B 49/00** (2006.01)**E21B 43/267** (2006.01)(52) **U.S. Cl.**CPC **E21B 43/26** (2013.01); **E21B 43/267**
(2013.01); **E21B 47/06** (2013.01); **E21B**
49/006 (2013.01)

(57)

ABSTRACT

Methods of fracturing a hydrocarbon formation are described herein. A method may include propagating one or more first fractures from a first wellbore in the hydrocarbon formation, allowing a selected period of time to elapse so that at least a portion of the first fractures close, and propagating at least one second fracture in the wellbore or a second wellbore after the elapsed selected period of time.



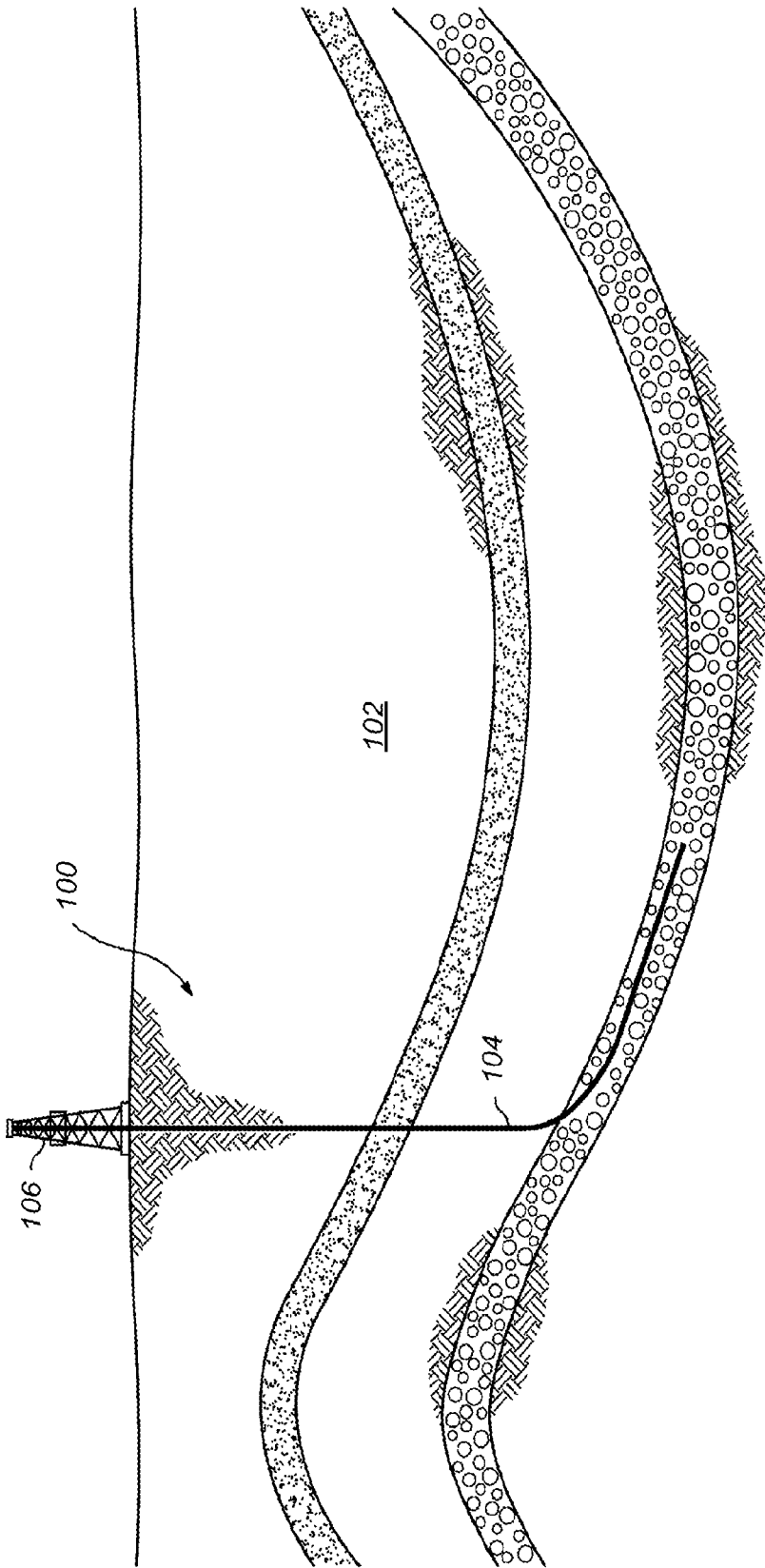


FIG. 1

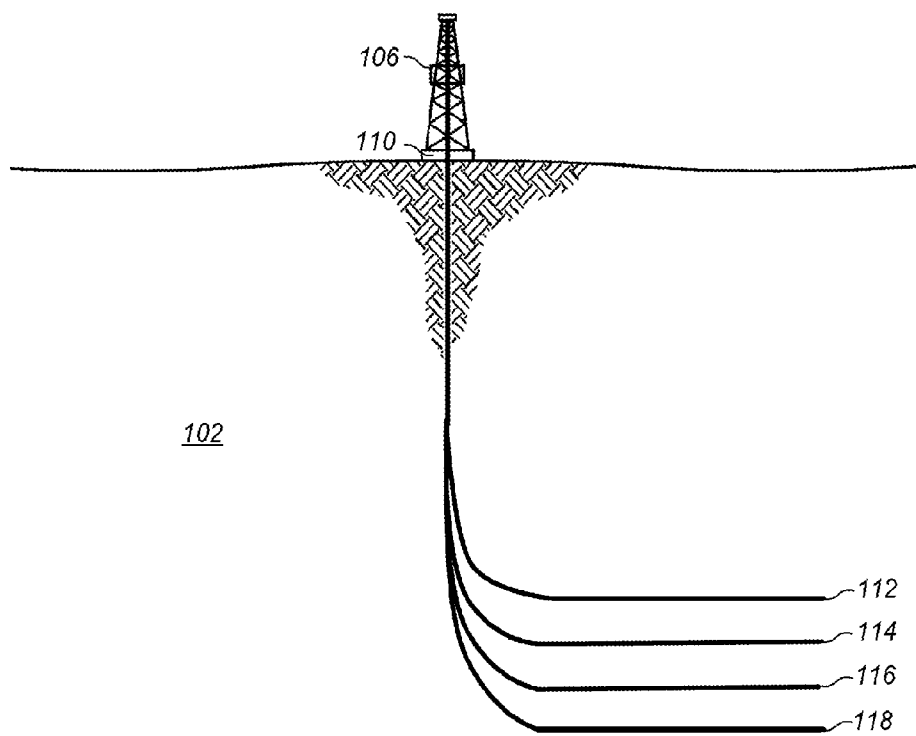


FIG. 2

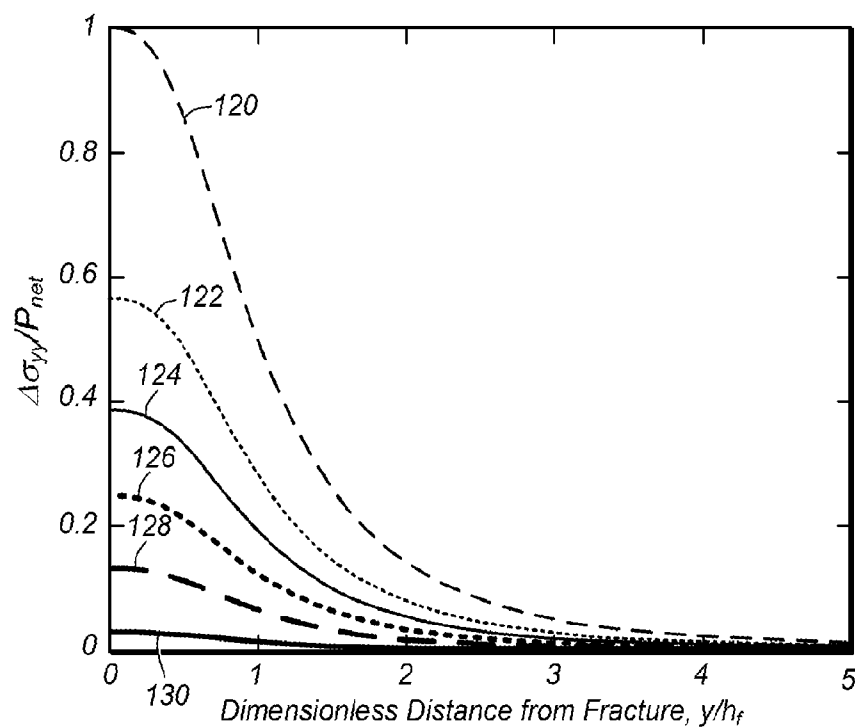


FIG. 3A

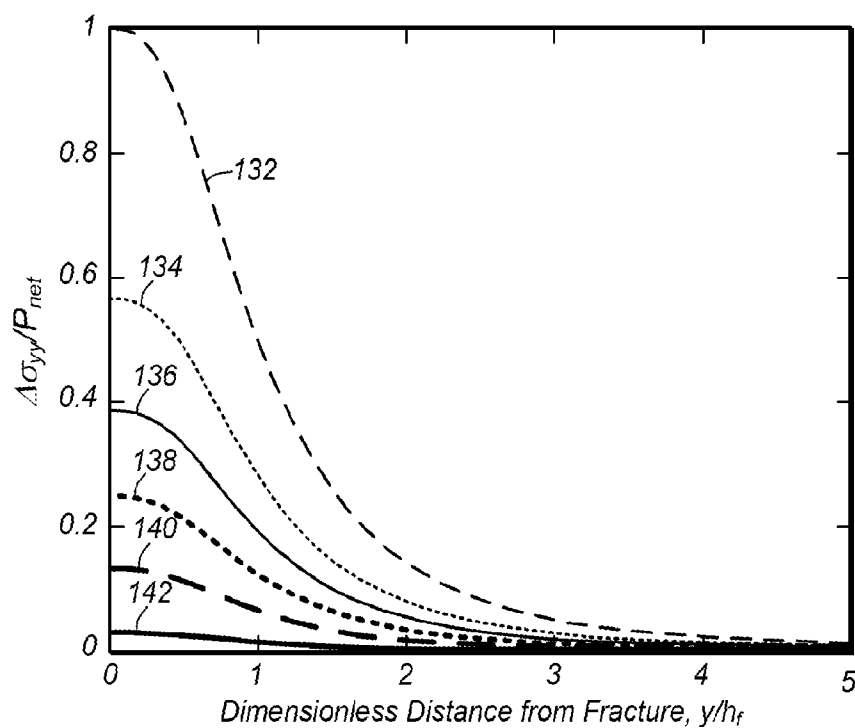


FIG. 3B

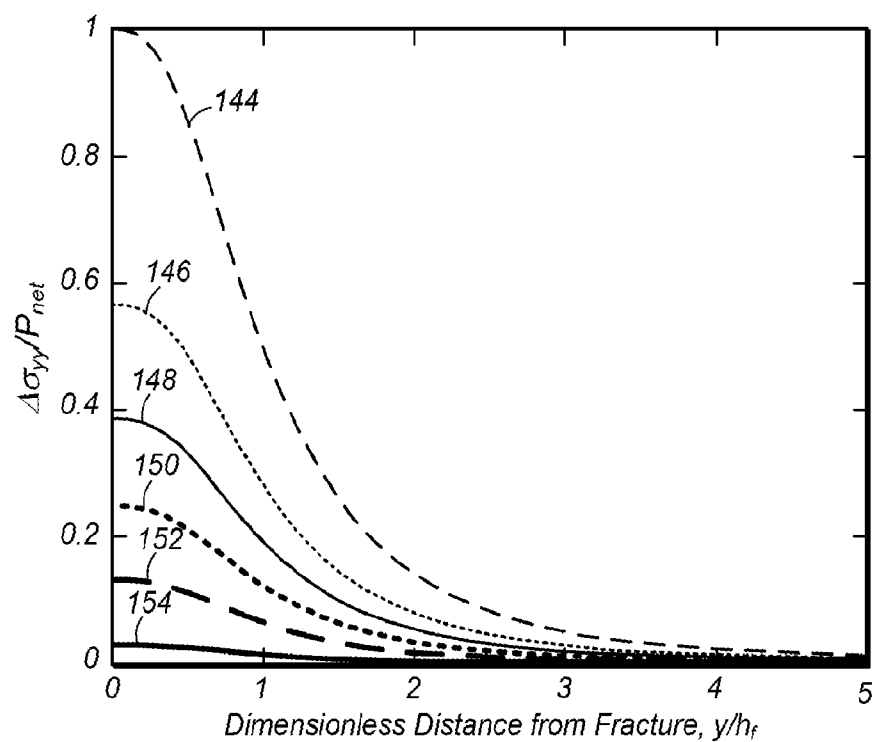


FIG. 4A

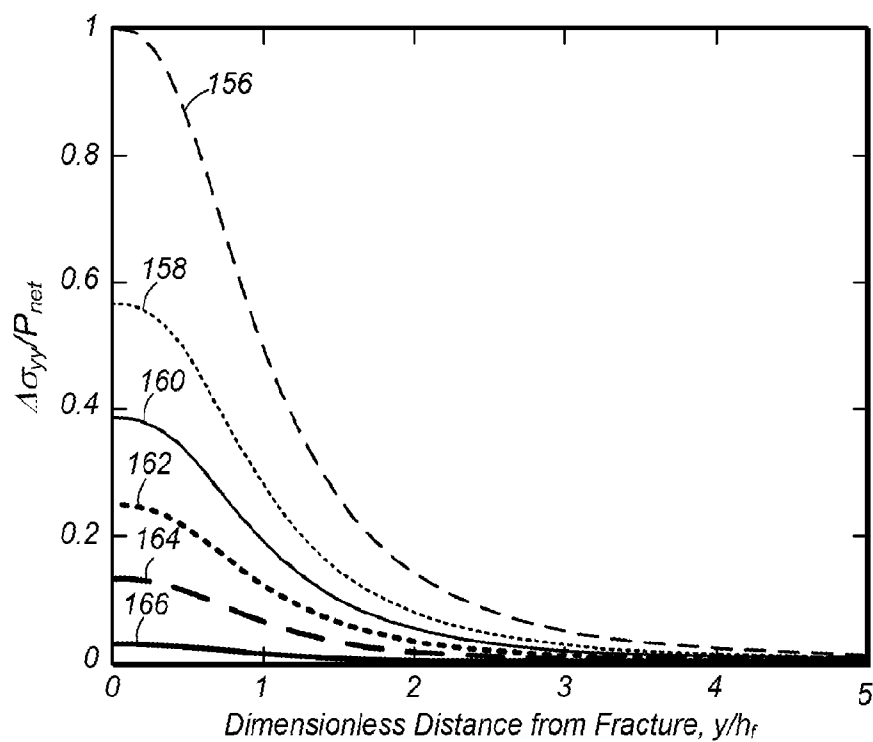


FIG. 4B

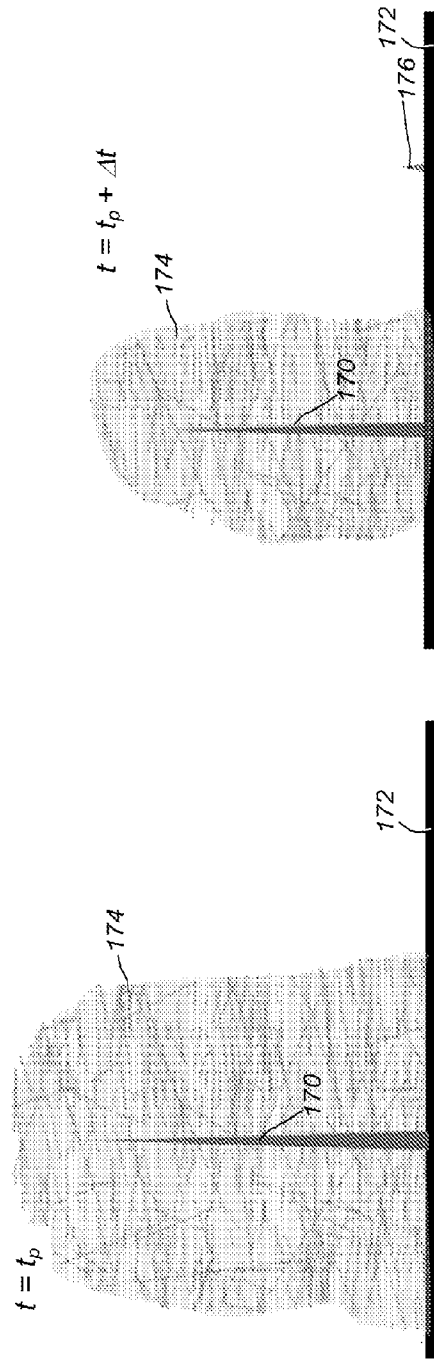


FIG. 5A

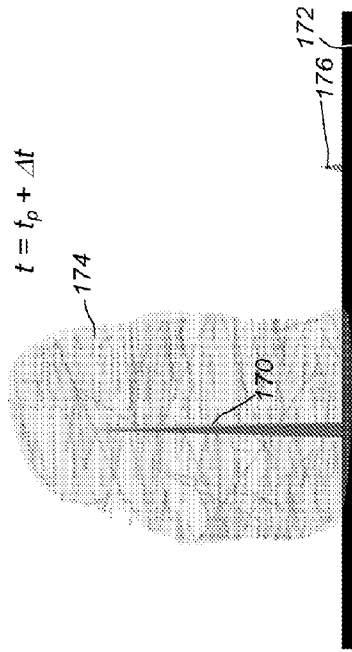


FIG. 5B

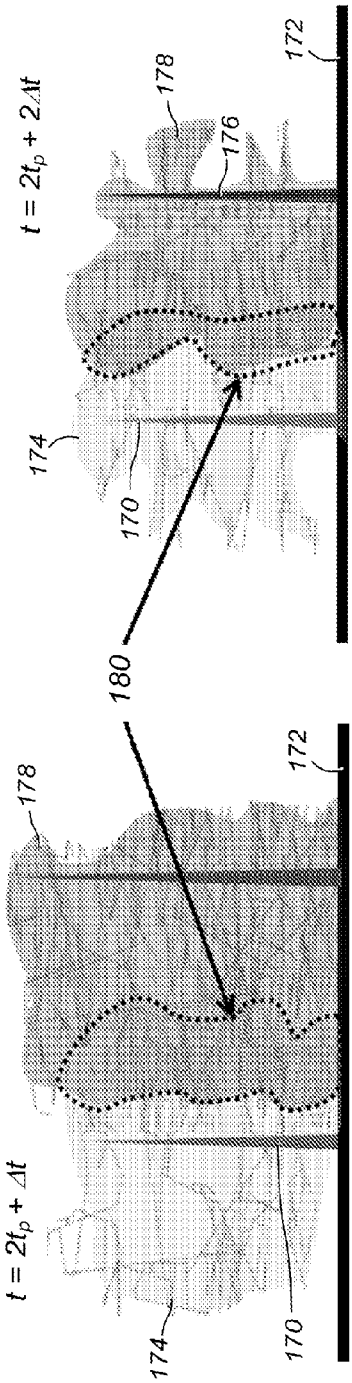


FIG. 5C

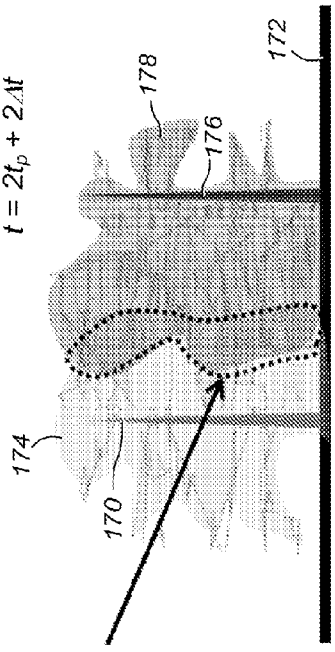


FIG. 5D

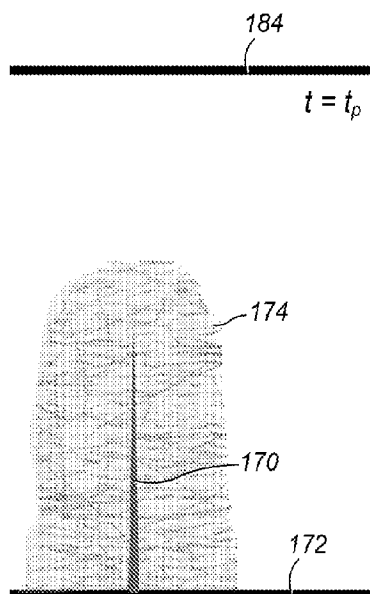


FIG. 6A

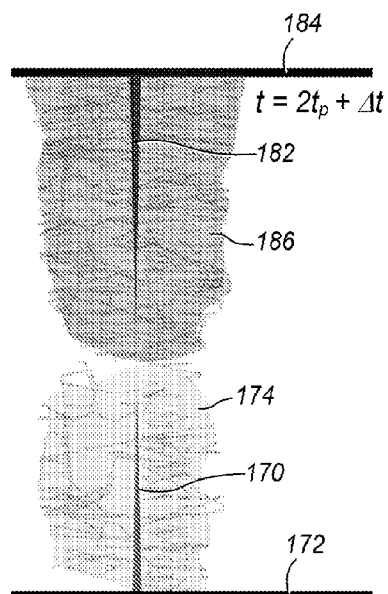


FIG. 6B

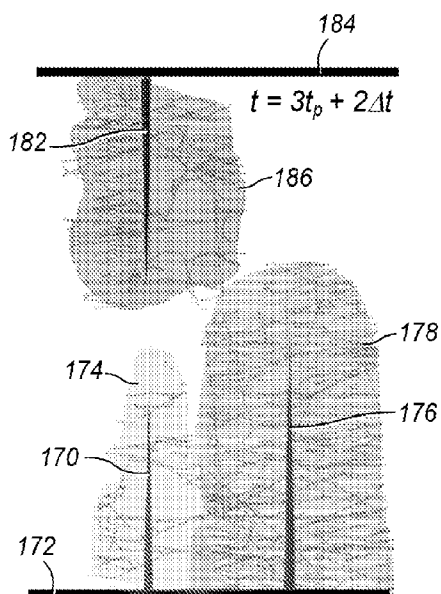


FIG. 6C

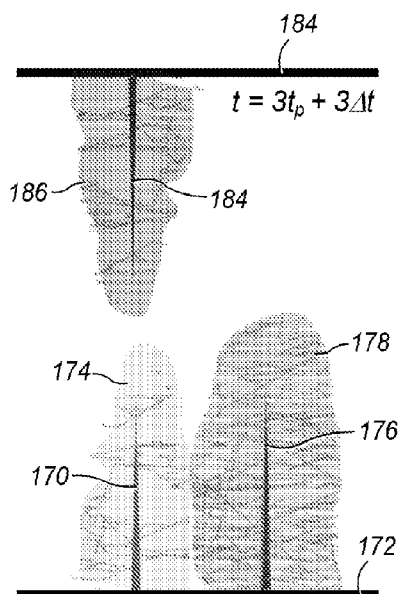


FIG. 6D

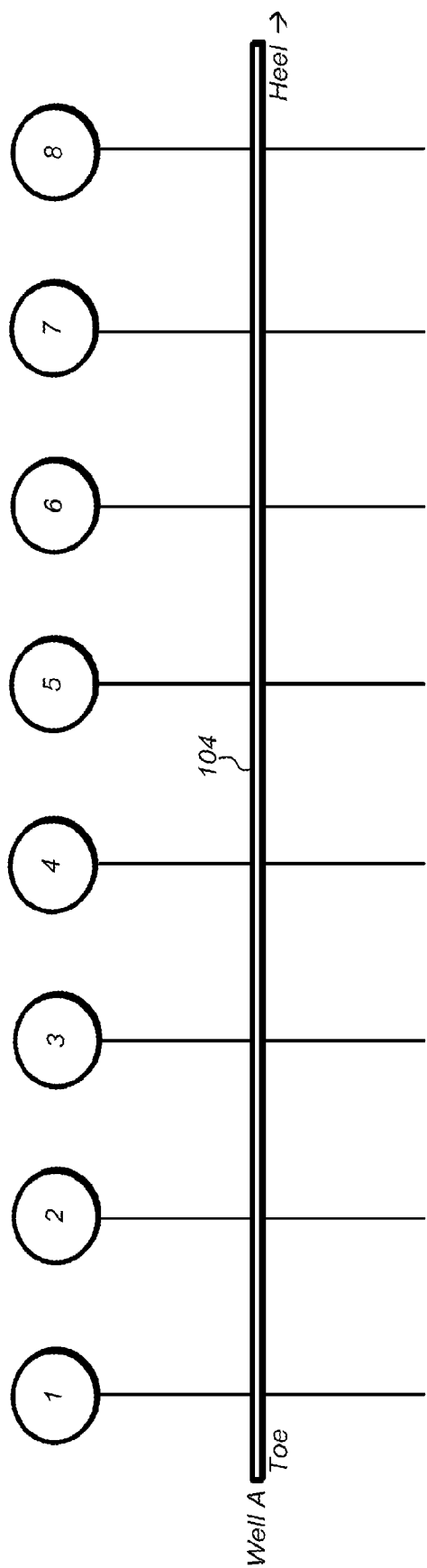


FIG. 7

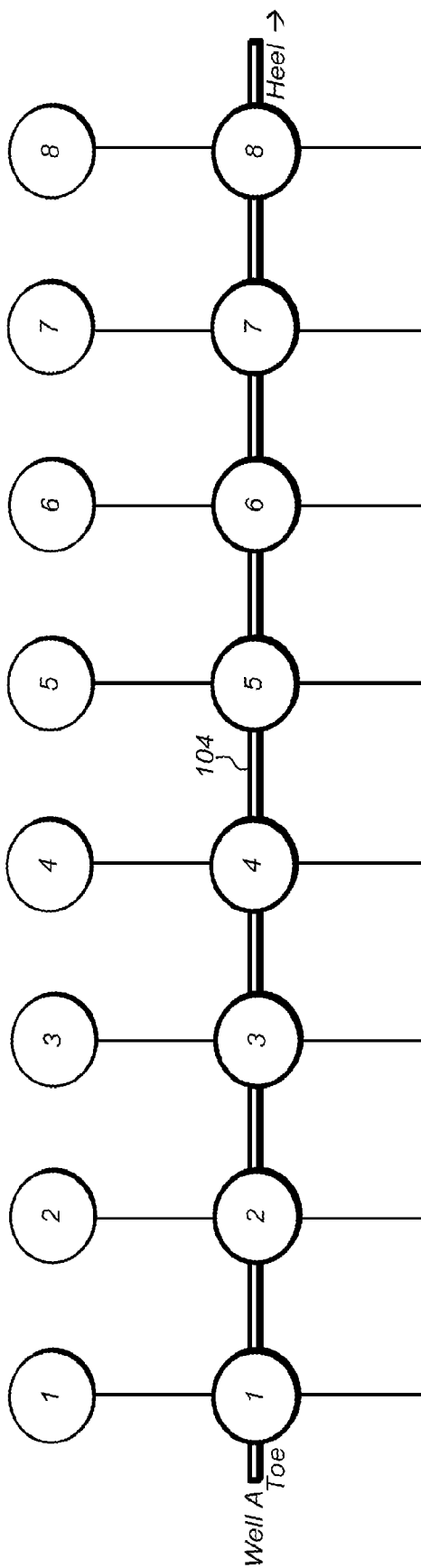


FIG. 8

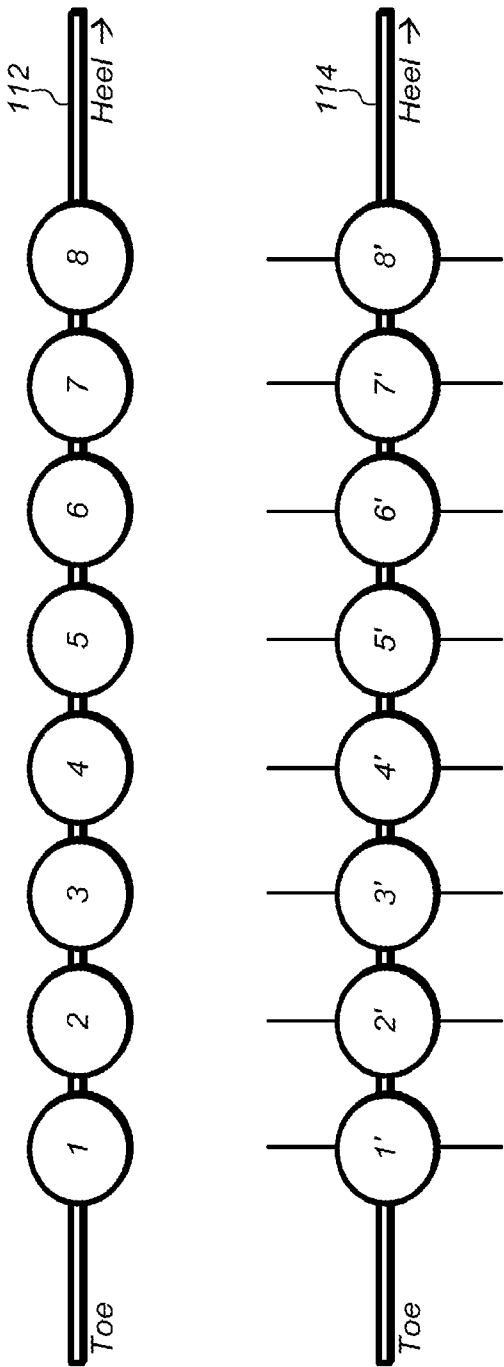


FIG. 9

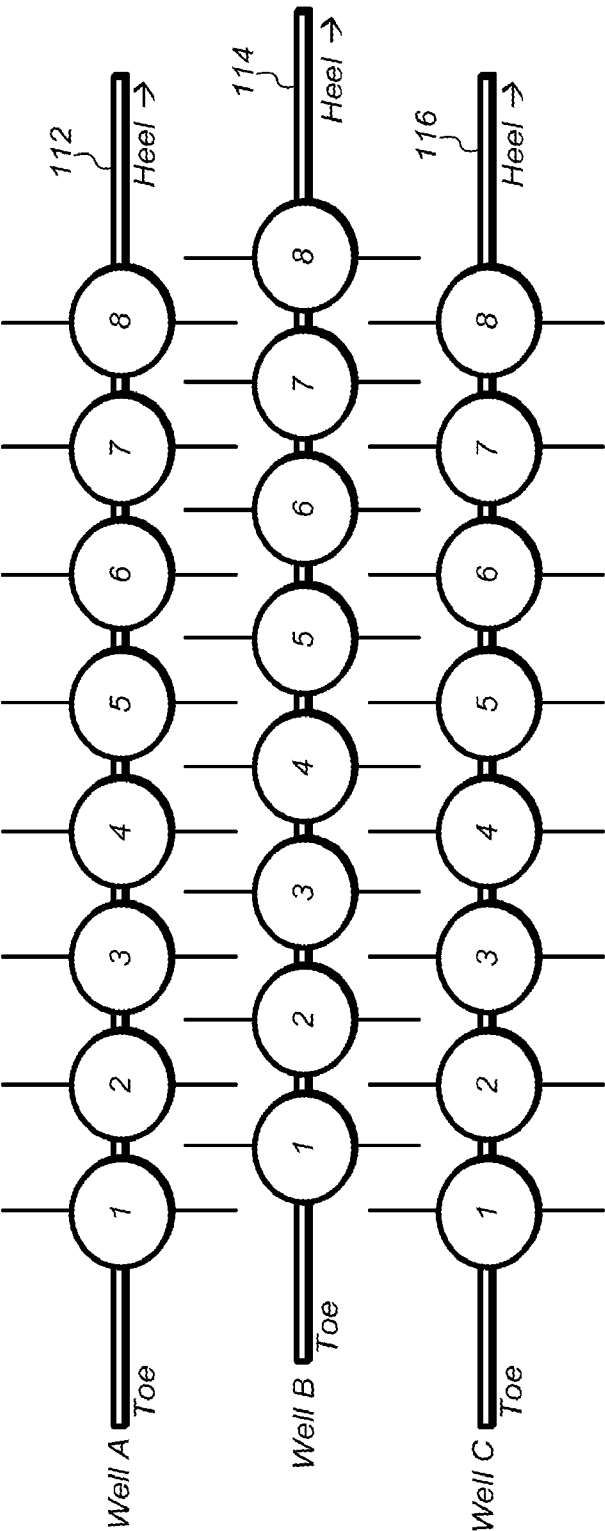


FIG. 10

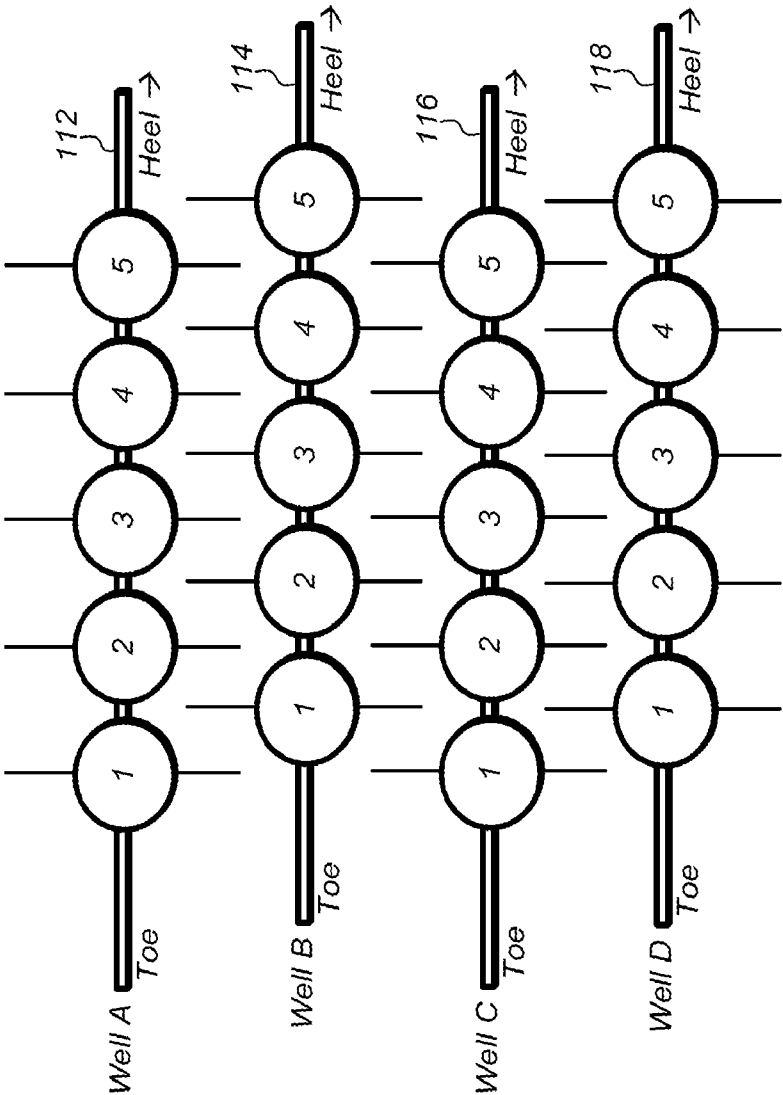


FIG. 11

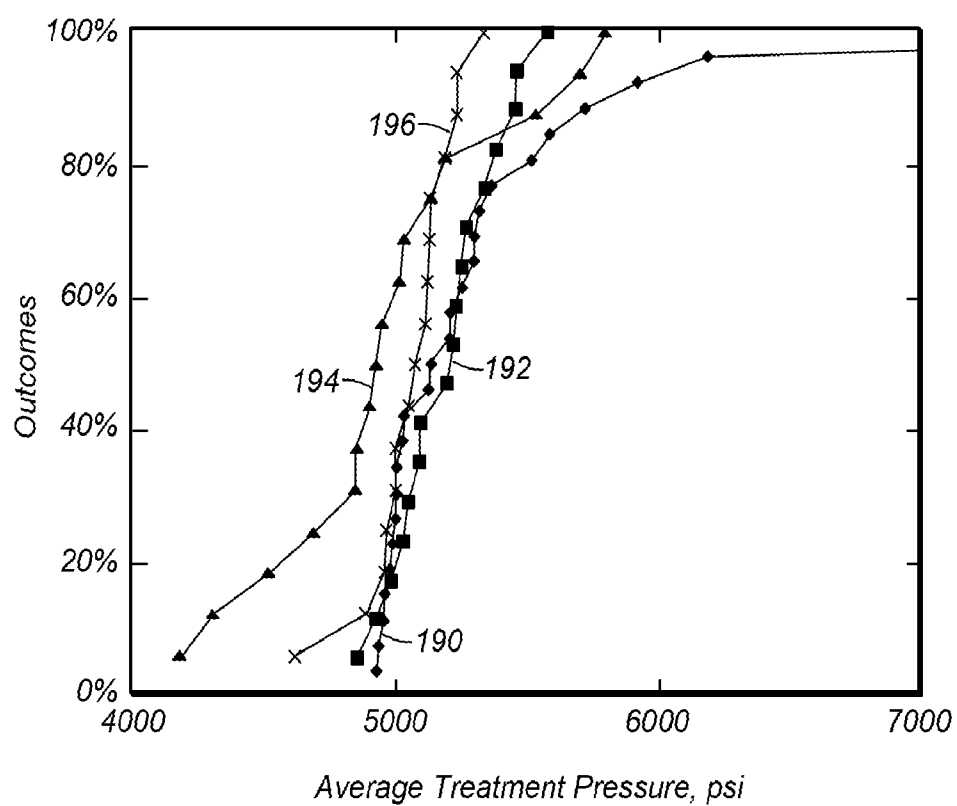


FIG. 12

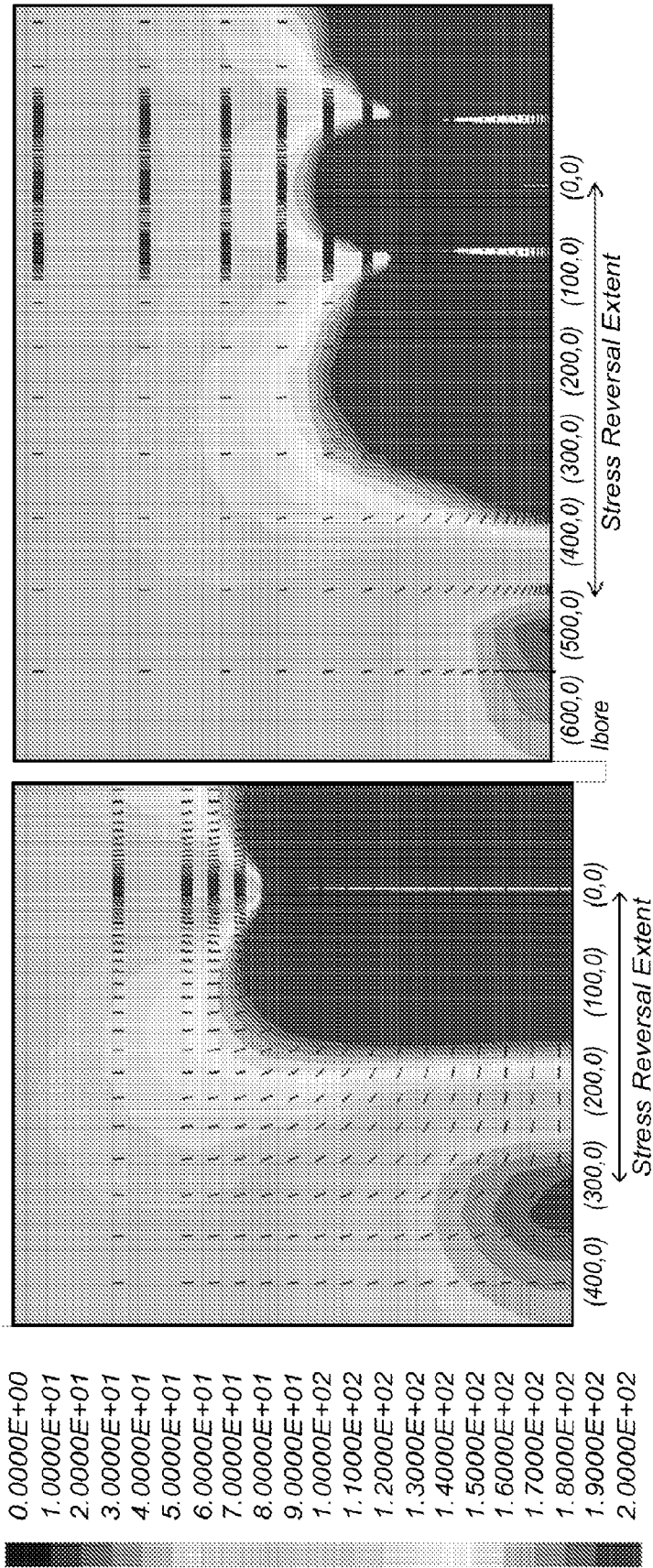


FIG. 13A

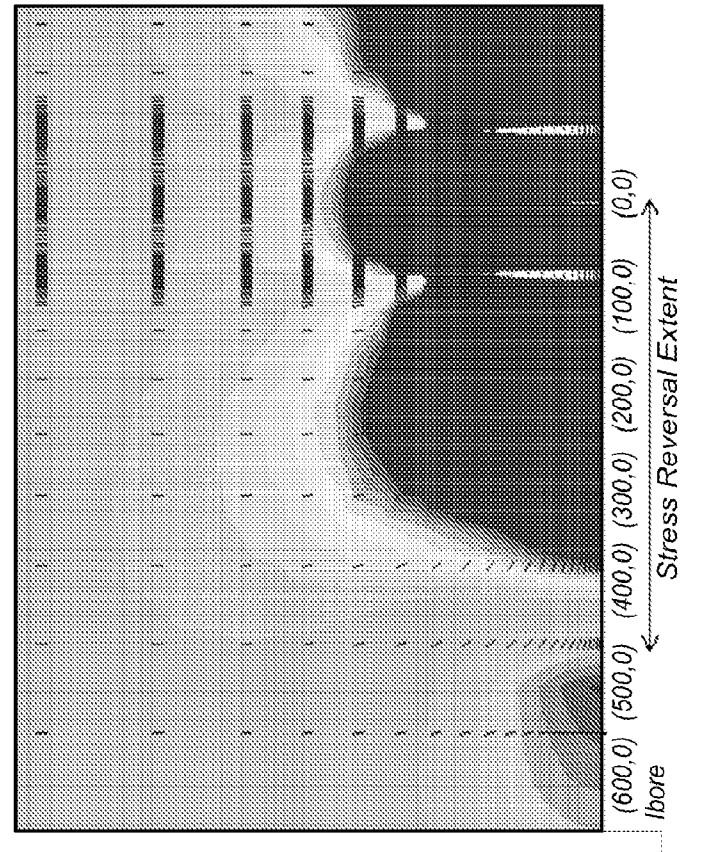


FIG. 13B

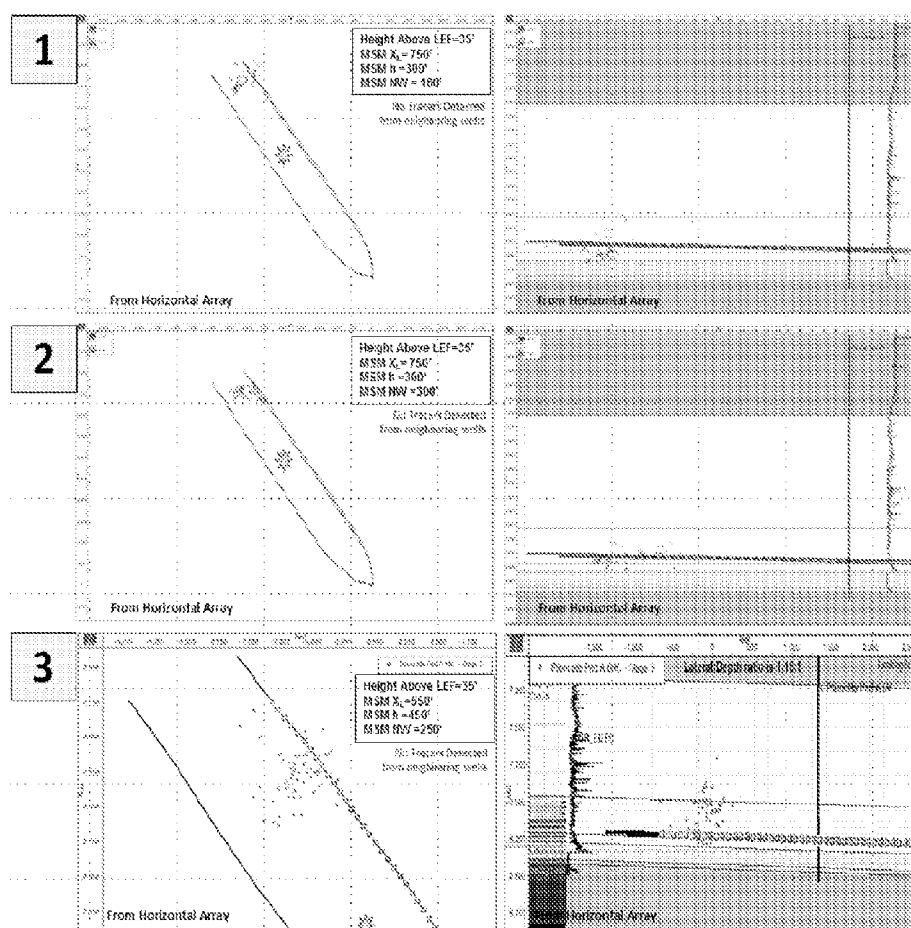
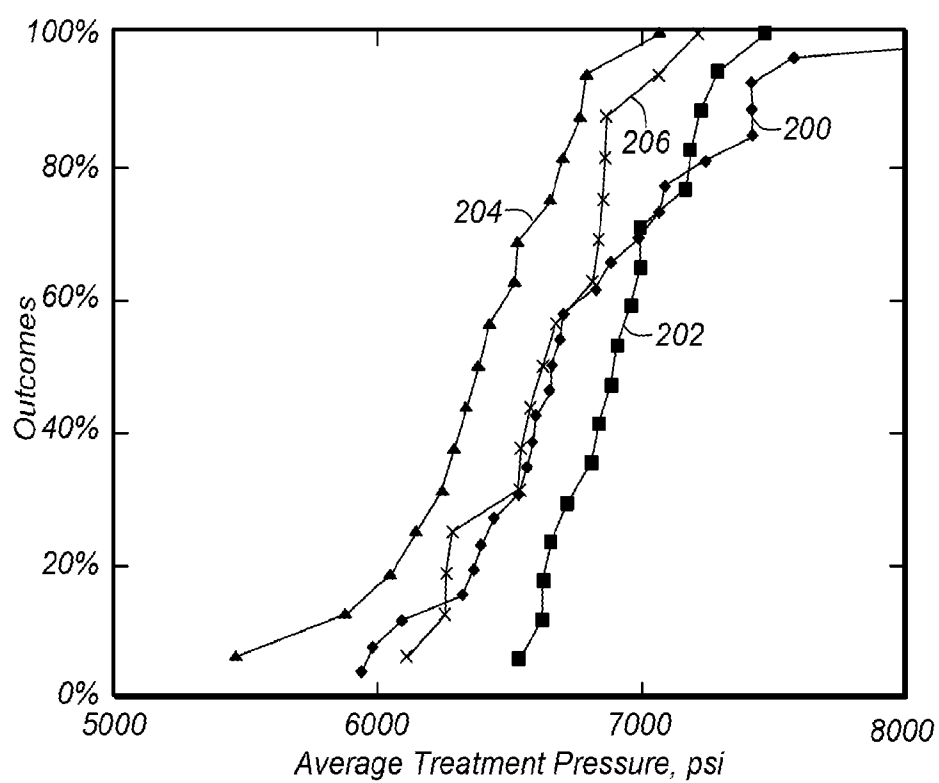


FIG. 14

**FIG. 15**

Stage	A6 Pad										Stage
	A	B			C			D			
Completion Order	2	3 - zippered with A6D			1			3 - zippered with A6B			
Tracer Injected	None	Ir - Iridium			Sc - Scandium			Sb - Antimony			Tracer Injected
Logged	No	Ir	Sc	Sb	Ir	Sc	Sb	Ir	Sc	Sb	Logged
1	x		No	Yes	No		No	No	No		1
2	x		No	Yes	No		No	No	No		2
3	x		No	Yes	No		No	No	No		3
4	x		No	Yes	No		No	No	No		4
5	x		No	Yes	No		No	No	No		5
6	x		No	Yes	No		No	No	No		6
7	x		No	Yes	No		No	No	No		7
8	x		No	Yes	No		No	No	No		8
9	x		No	Yes	No		No	No	No		9
10	x		No	Yes	No		No	No	No		10
11	x		No	Yes	No		No	No	No		11
12	x		No	Yes	No		No	No	No		12
13	x		No	Yes	No		No	Yes	No		13
14	x		No	No	No		No	Yes	No		14
15	x		No	No	No		No	No	No		15
16	x		No	No	No		No	No	No		16
17	x							No	No		17
18	x										18
19	x										19
20	x										20
21	x										21
22	x										22
23	x										23
24	x										24
25	x										25
26	x										26

FIG. 16

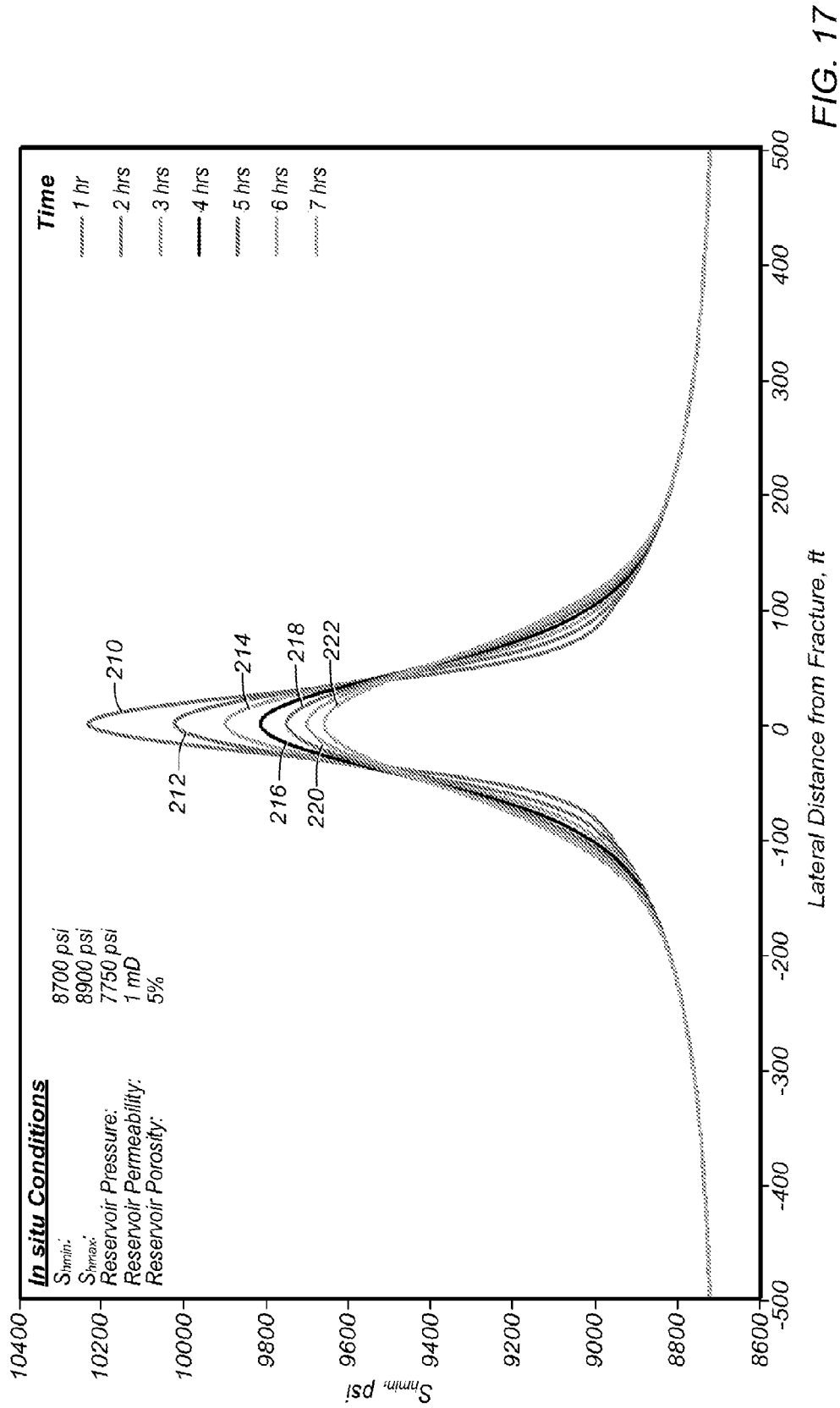


FIG. 17

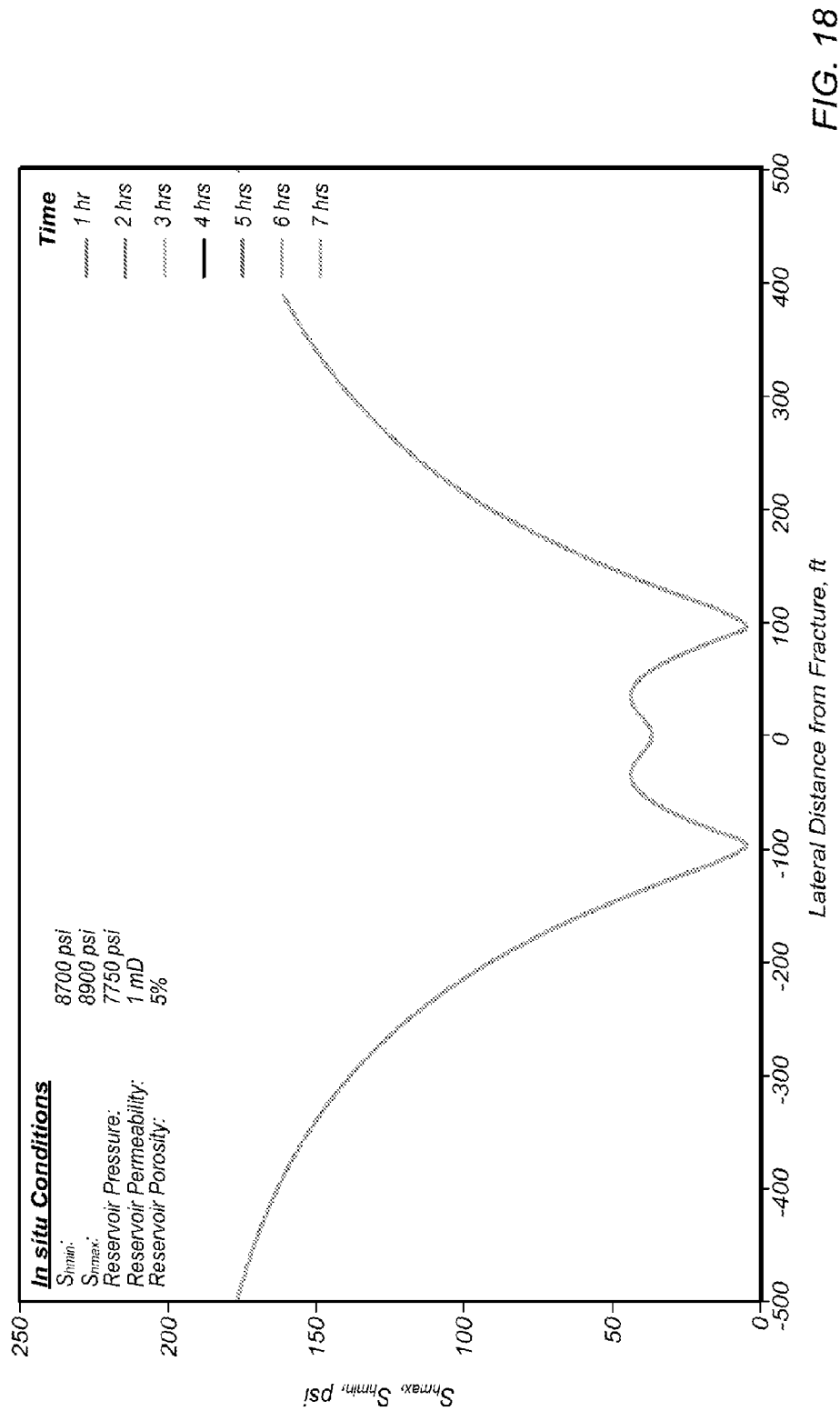
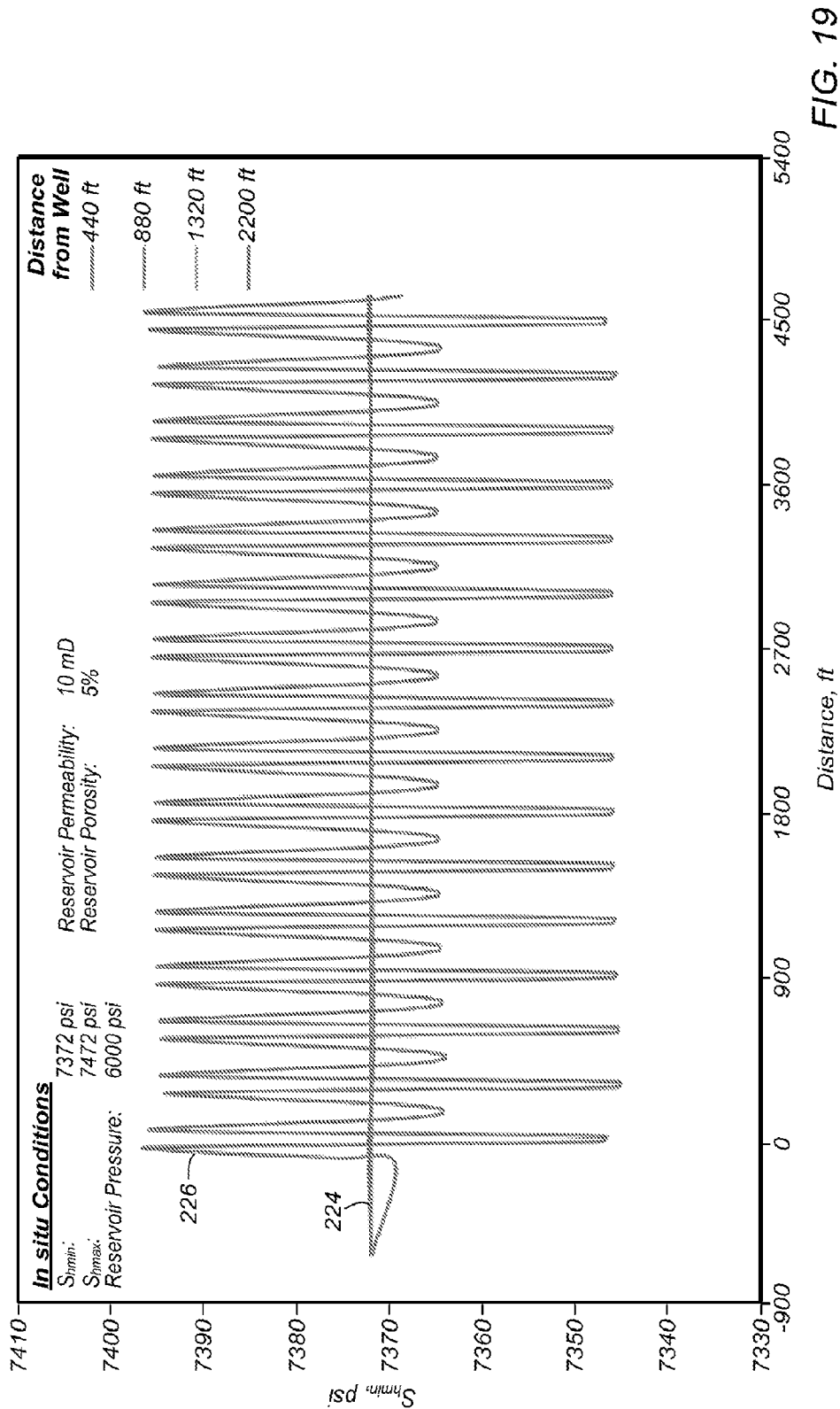


FIG. 18



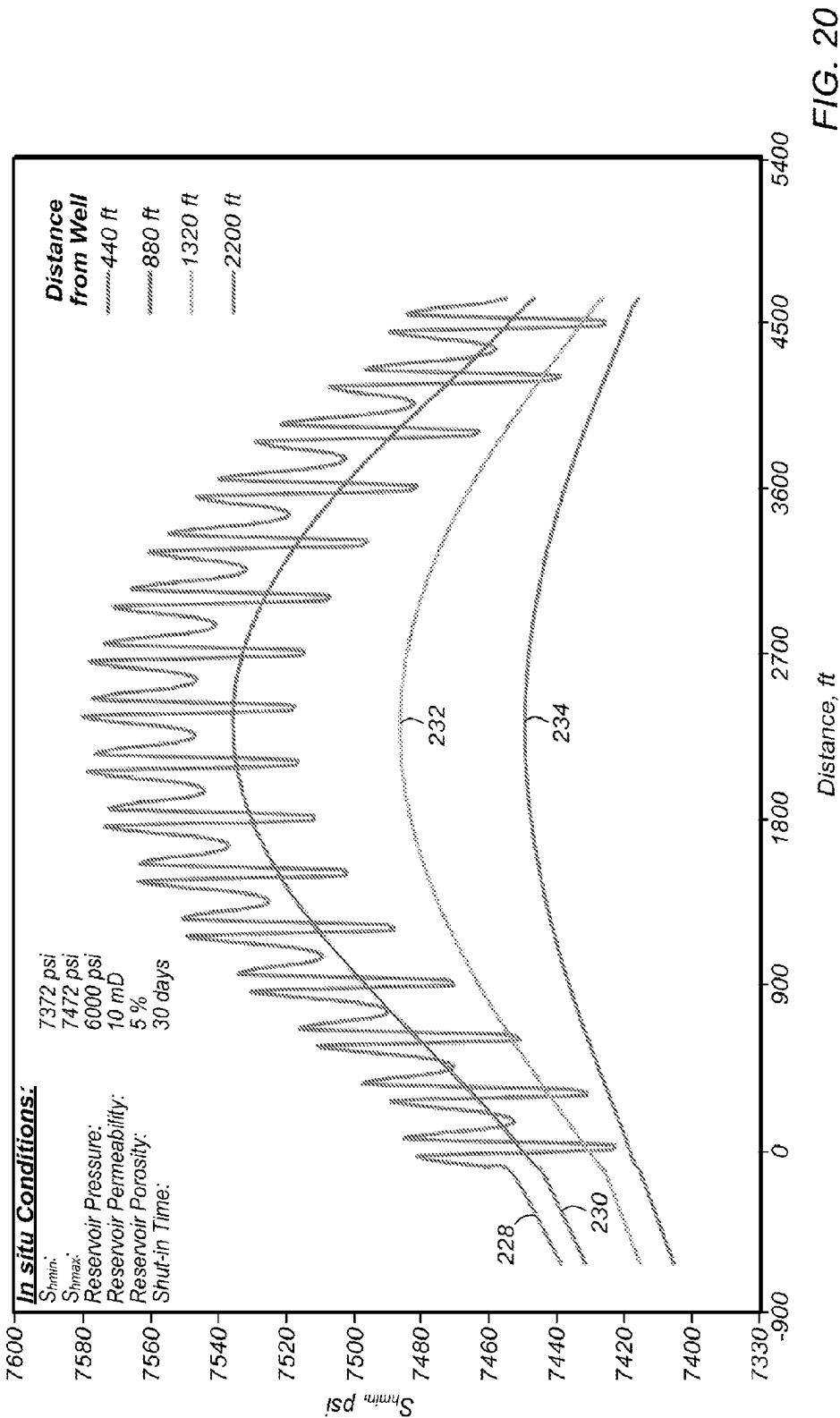


FIG. 20

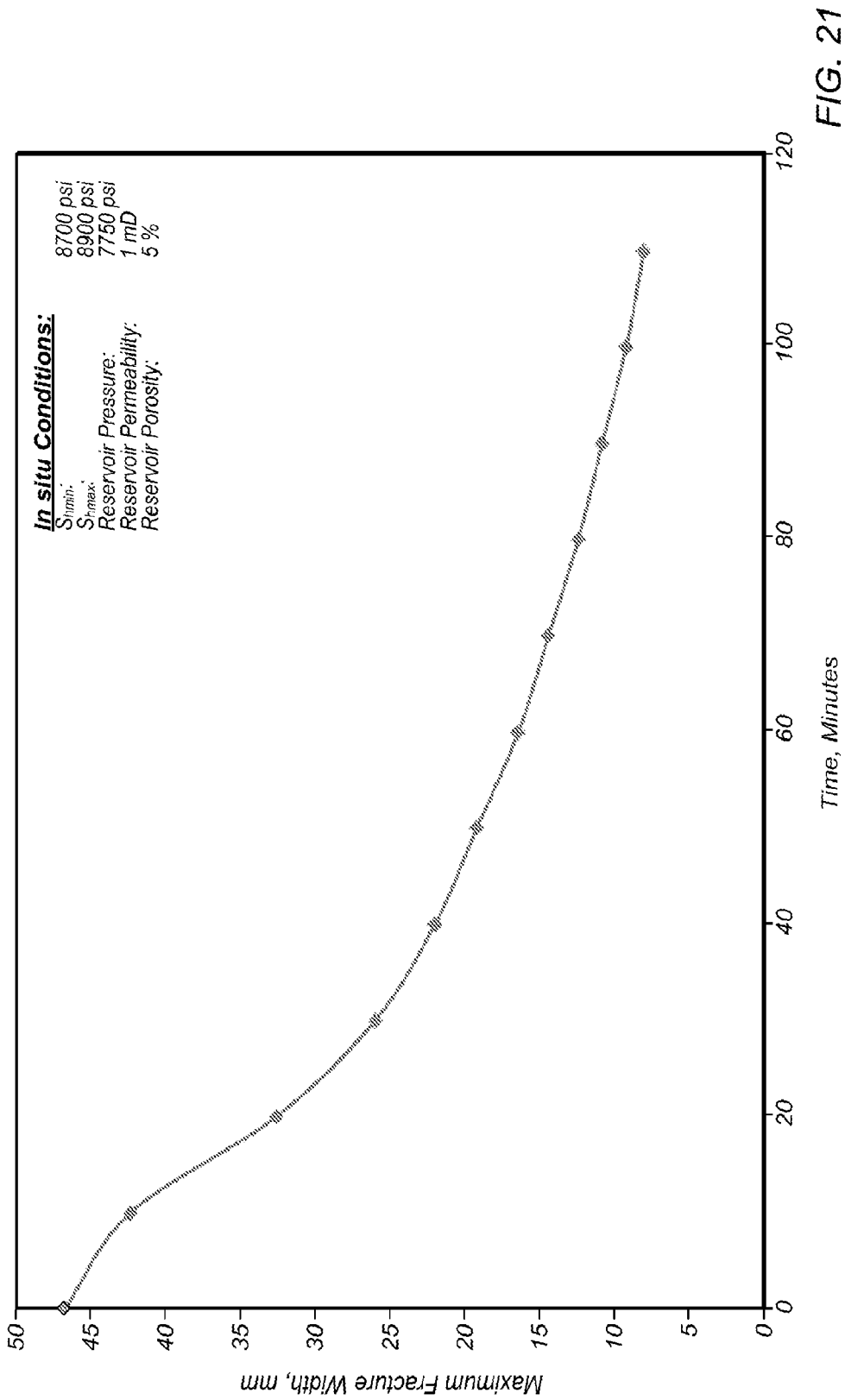
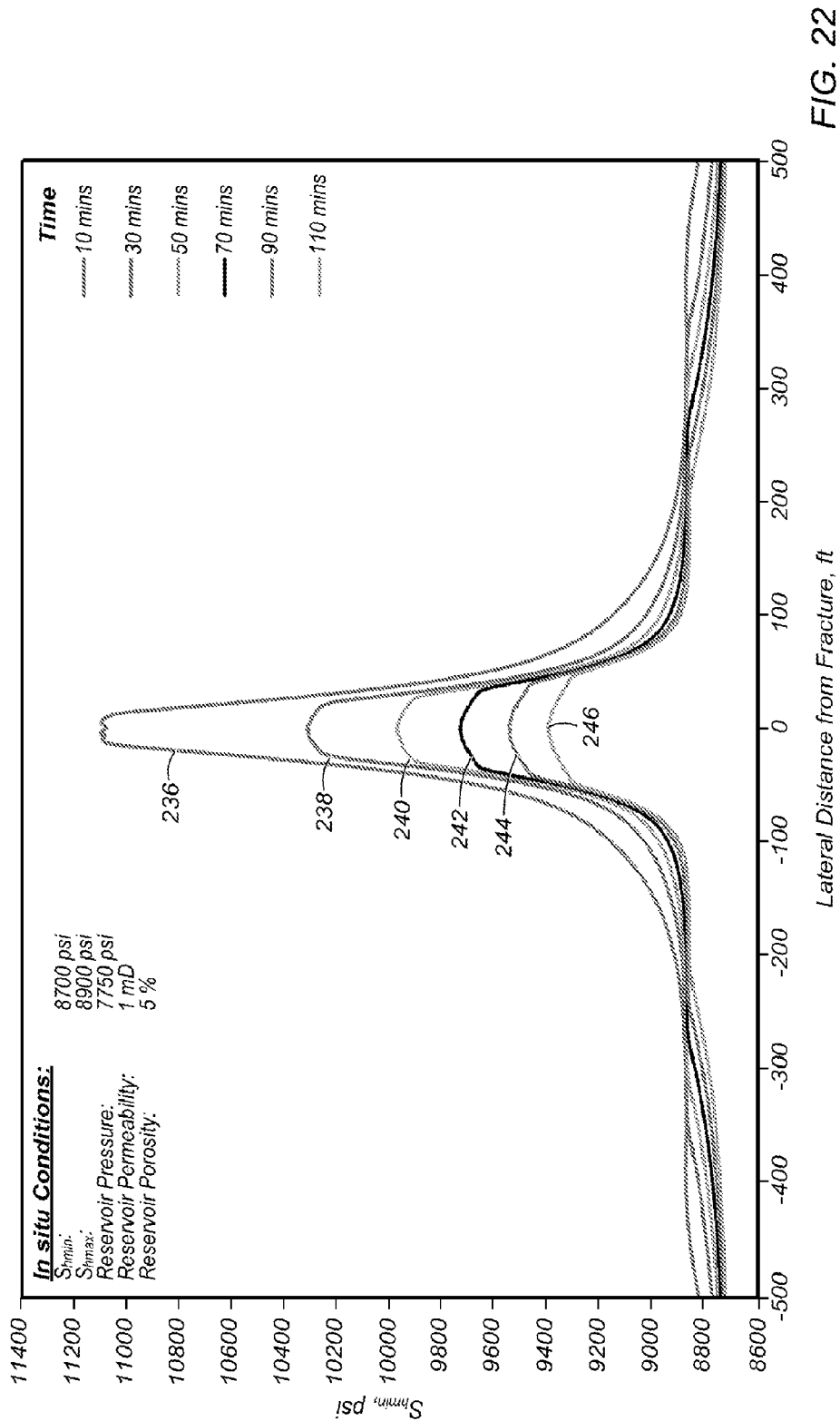


FIG. 21



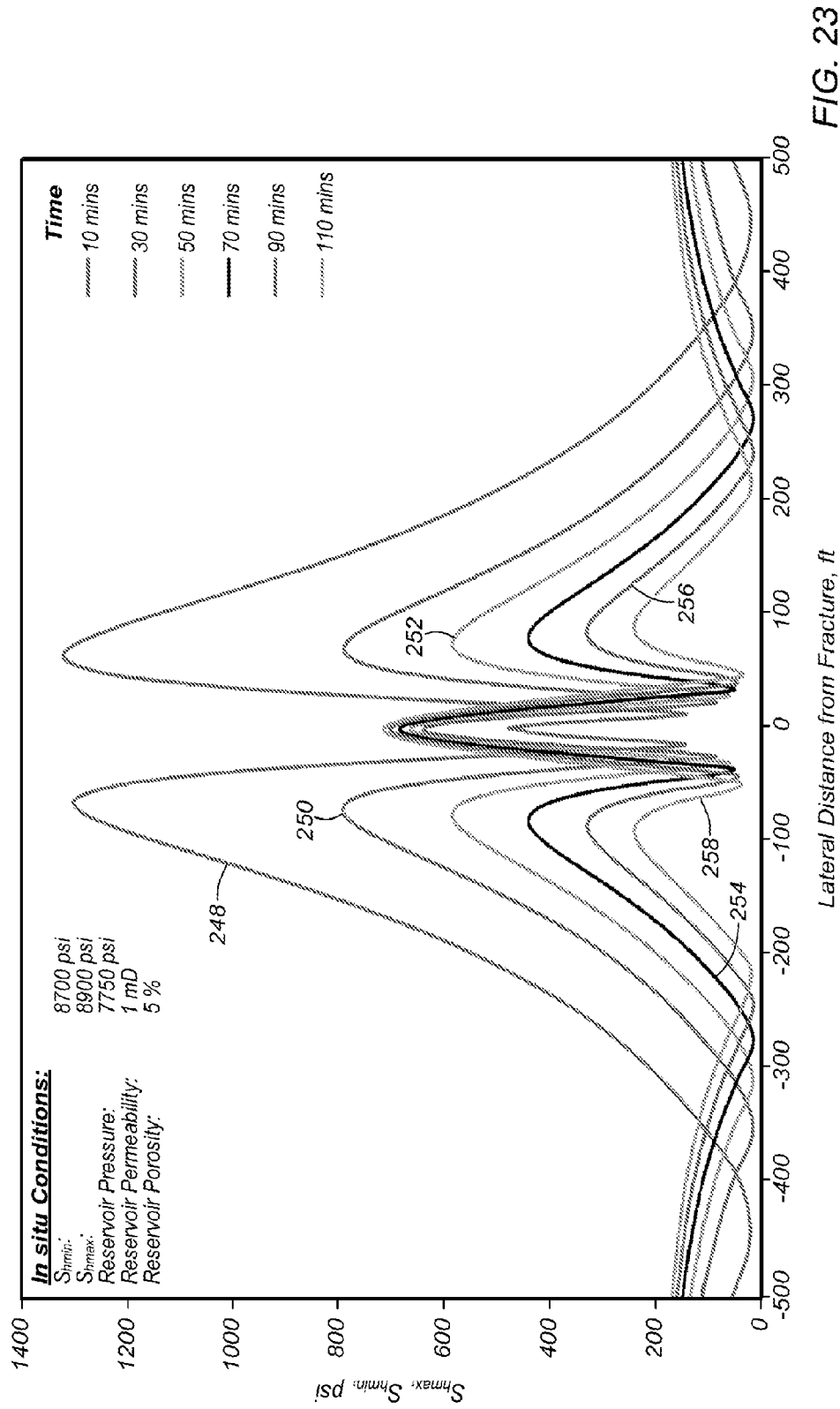


FIG. 23

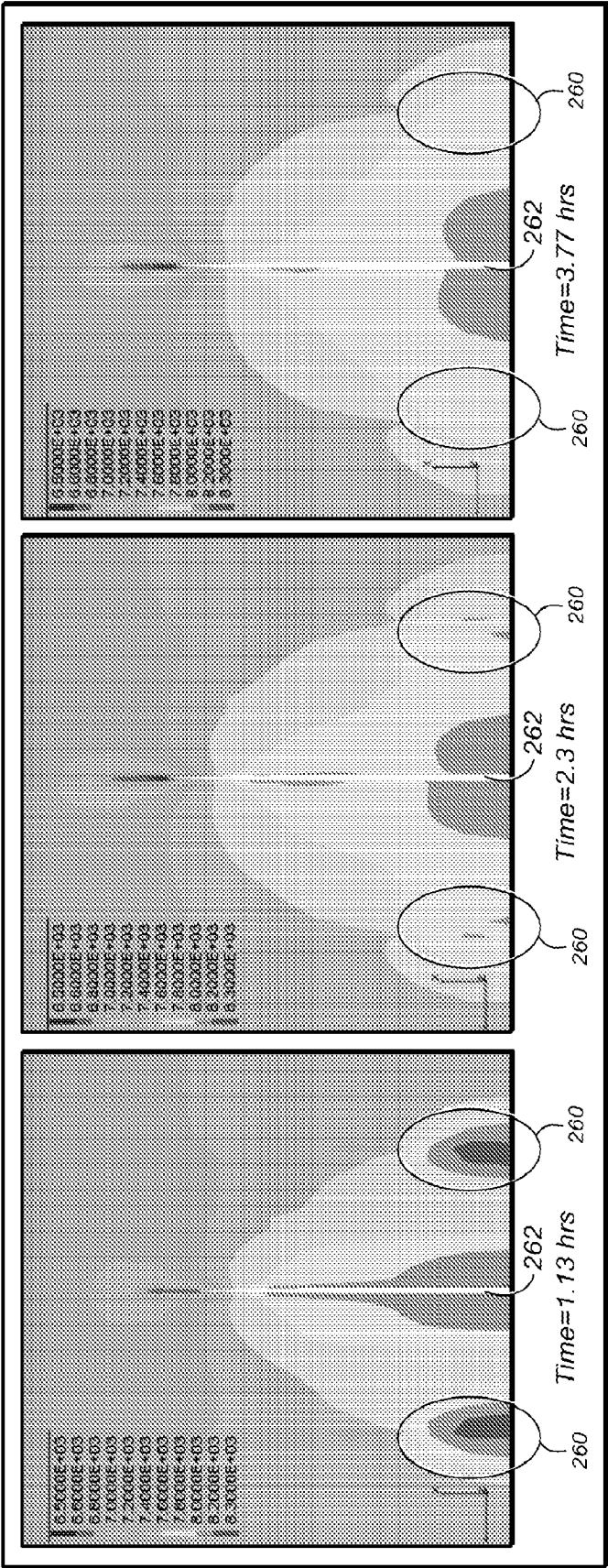
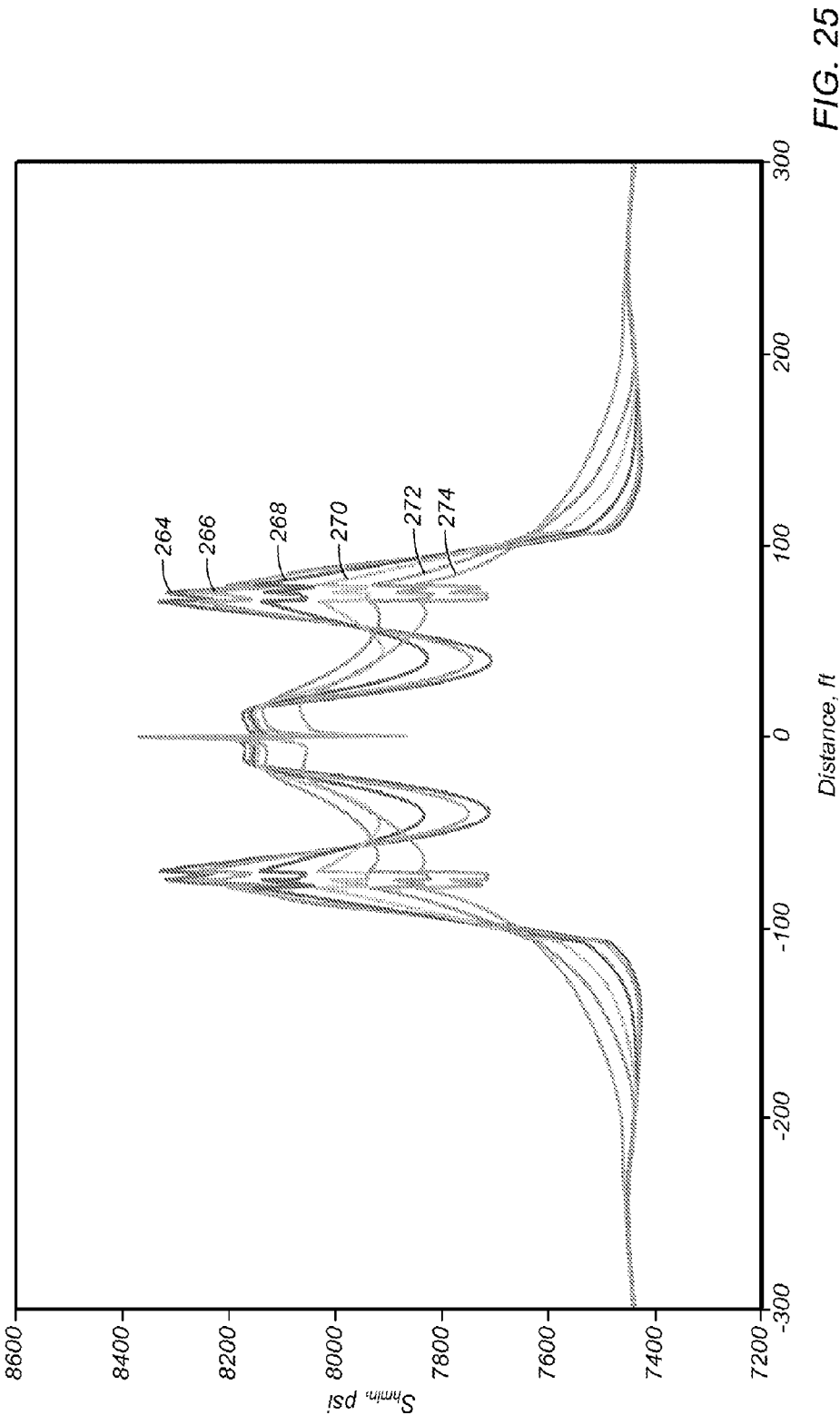
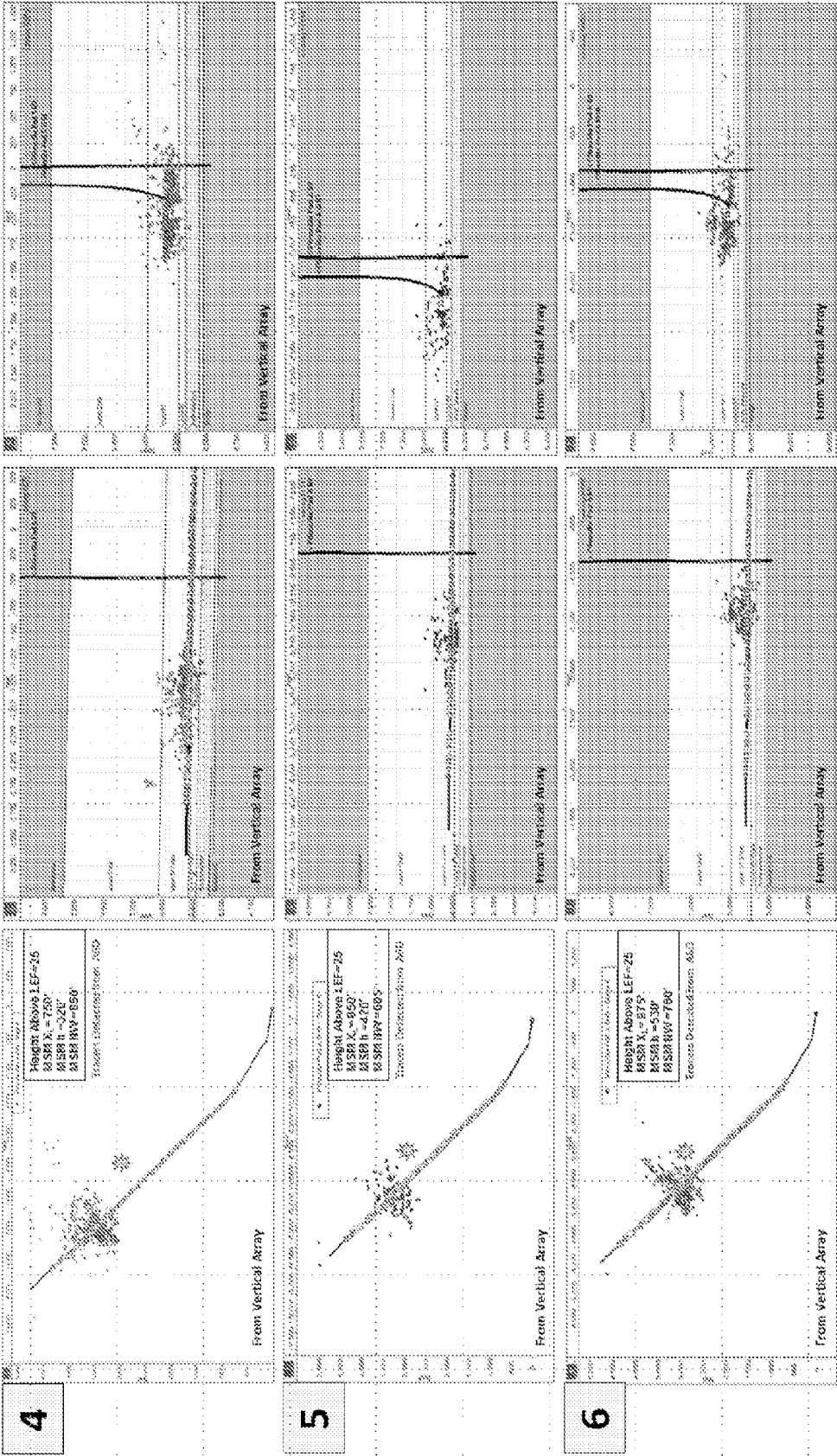


FIG. 24





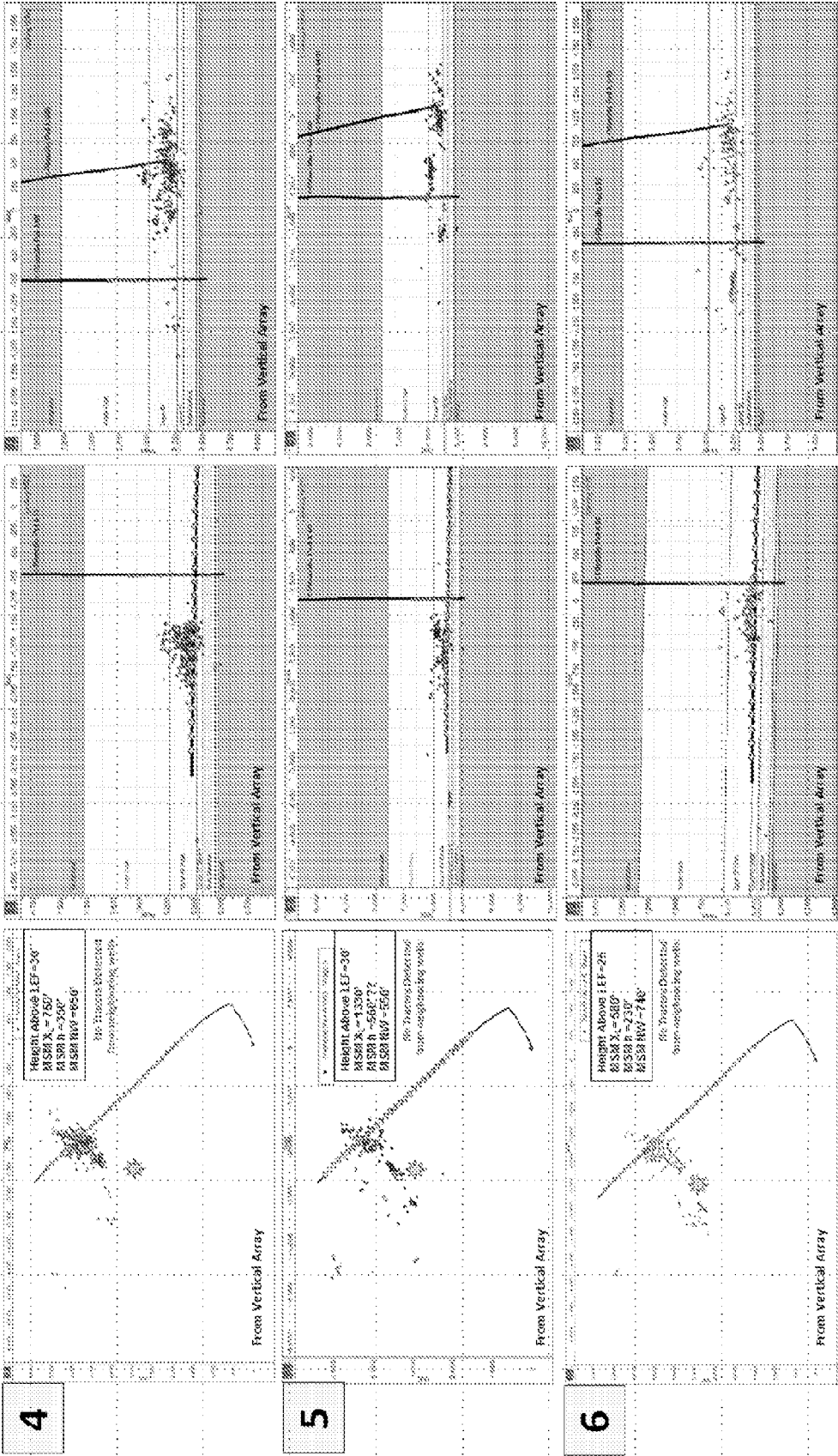


FIG. 27

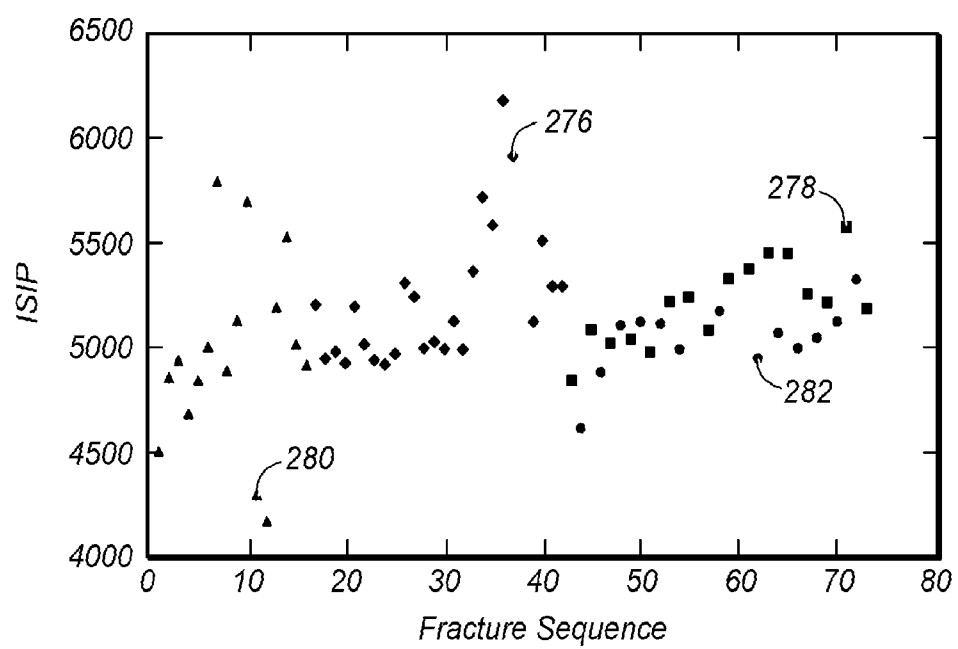


FIG. 28

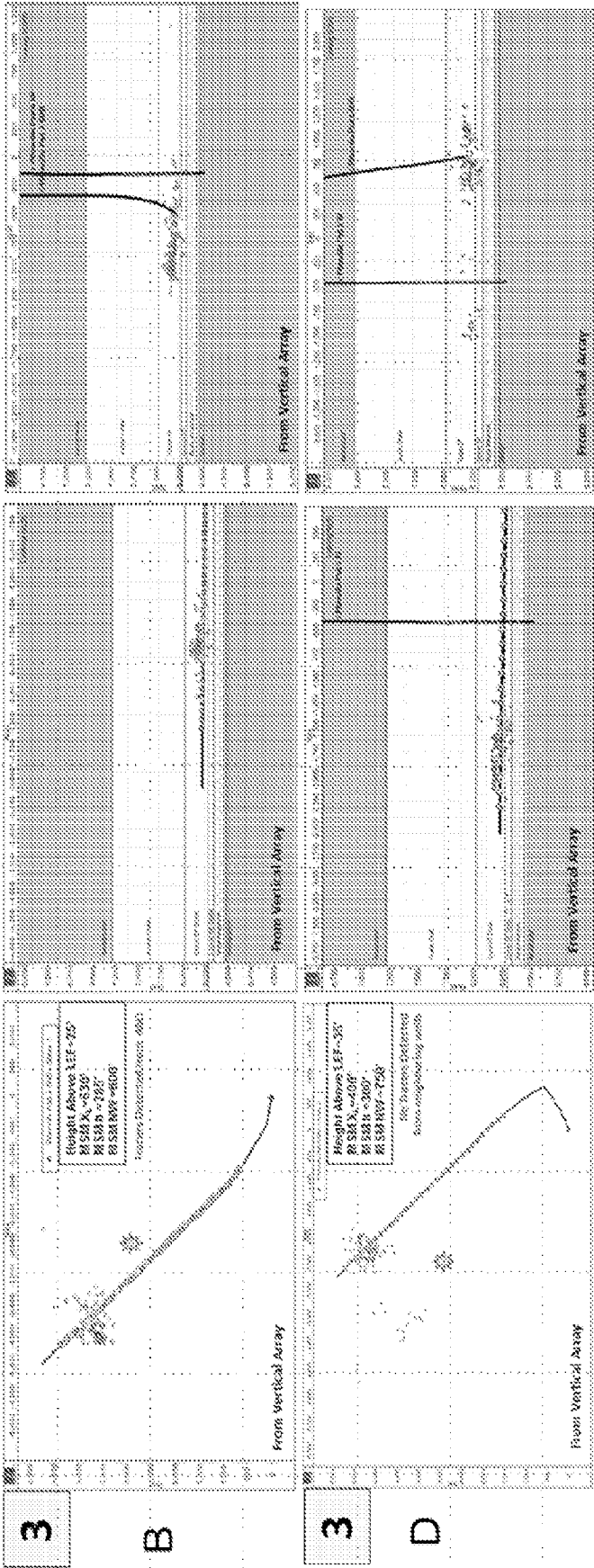


FIG. 29

METHODS FOR TIME-DELAYED FRACTURING IN HYDROCARBON FORMATIONS

BACKGROUND

[0001] 1. Field of the Invention

[0002] The present invention relates generally to methods and systems for production of hydrocarbons and/or other products from various subsurface formations such as hydrocarbon containing formations. In particular, the invention relates to methods of fracturing hydrocarbon formations.

[0003] 2. Description of Related Art

[0004] Hydrocarbon (for example, oil, natural gas, etc.) reservoirs may be found in geologic formation that have little to no porosity (for example, shale, sandstone, etc.). The hydrocarbons may be trapped within fractures and pore spaces of the formation. Additionally, the hydrocarbons may be adsorbed onto organic material of the shale formation. The rapid development of extracting hydrocarbons from unconventional reservoirs may be tied to the combination of horizontal drilling and hydraulic fracturing ("fracing") of the formations. Horizontal drilling (drilling along and within hydrocarbon reservoirs) of a formation has increased production of hydrocarbons within the reservoirs as compared to vertical drilling. Additionally, more hydrocarbons may be captured by increasing the number of fractures in the formation, increasing the size of already present fractures through fracturing, and/or increasing the effectiveness of the fractures to enhance hydrocarbons drainage from the formation. The effectiveness of hydraulic fractures for draining the reservoir is related to the spatial extent of the fractures and the net area of contact between the fracture surface and the hydrocarbon containing reservoir.

[0005] Horizontal well hydraulic fracturing in formations having low permeability (for example, shale or tight sand formations) is sometimes associated with complex fracture-growth patterns. This complexity may often be associated with the interaction of the hydraulic fracture with the pre-existing heterogeneity in the rock fabric or on the creation of fractures that may or may not contain proppant. Complex fractures may have a detrimental effect on the production response of wells because of the reduction in fracture length and width and loss of fluid due to the secondary fractures and fissures. However, the same complex fracturing may improve production from very low permeability unconventional reservoirs where the fluids can only be drained from areas close to the fracture surface. In these reservoirs, maximizing fracture complexity leads to maximizing the contact area of the reservoir with the well. From microseismic and tiltmeter data collected over the last 10 years, a huge diversity in fracture propagation patterns has been observed.

[0006] Based on the above, better methods for fracturing hydrocarbon formations are desired, especially methods for fracturing reservoirs having complex fracture growth.

SUMMARY

[0007] Methods of fracturing hydrocarbon formation are described herein. In some embodiments, a method of fracturing a hydrocarbon formation includes propagating one or more first fractures from a first wellbore in the hydrocarbon formation; allowing a selected period of time to elapse so that

at least a portion of the first fractures close; and propagating at least one second fracture in the wellbore after the selected period of time.

[0008] In some embodiments, a method of fracturing a hydrocarbon formation includes propagating one or more first fractures from a wellbore in the hydrocarbon formation; analyzing a pressure in the first fracture to determine closure of at least one or more of the first fractures; propagating at least one second fracture from the wellbore or from a second wellbore based on the analyzed closure pressure; and producing formation fluid from hydrocarbon formation.

[0009] In some embodiments, a method of fracturing a hydrocarbon formation, includes propagating one or more first fractures from a wellbore in the hydrocarbon formation; determining a minimum start time for propagating at least one second fracture from the wellbore and/or a second wellbore based on closure of at least some of the first fractures; and propagating at least one second fracture from the wellbore based on the minimum start time, wherein the second fracture at a least minimum spacing distance away from the first fracture.

[0010] In some embodiments, a method of fracturing a hydrocarbon formation, includes: propagating one or more first fractures from a first wellbore of a plurality of wellbores in the hydrocarbon formation; allowing, at least a desired period of time before propagating a second fracture at a chosen distance in the first wellbore, wherein at least some of the first fractures close during the period of time; and propagating one or more second fractures from the first wellbore and/or a second wellbore in the hydrocarbon formation after fracture closure of at least some of the first fractures in the first wellbore, wherein the first wellbore and the second wellbore are in the same section of the hydrocarbon formation.

[0011] In further embodiments, features from specific embodiments may be combined with features from other embodiments. For example, features from one embodiment may be combined with features from any of the other embodiments.

[0012] In further embodiments, additional features may be added to the specific embodiments described herein.

BRIEF DESCRIPTION OF THE DRAWINGS

[0013] Advantages of the present invention may become apparent to those skilled in the art with the benefit of the following detailed description and upon reference to the accompanying drawings in which:

[0014] FIG. 1 depicts a schematic of an embodiment of producing formation fluids from a hydrocarbon formation.

[0015] FIG. 2 depicts a schematic of an embodiment of drilling pad for producing formation fluids from a hydrocarbon formation

[0016] FIGS. 3A and 3B are graphical depictions of the stress interference versus distance from fracture as a function of the closure of the fracture for various leak-off coefficients.

[0017] FIGS. 4A and 4B are graphical depictions of the stress interference versus distance from fracture as a function of the time of fracture closure.

[0018] FIG. 5A depicts a schematics of an embodiment of stimulated regions for a consecutively fractured well at the end of pumping after a first hydraulic fracturing treatment.

[0019] FIG. 5B depicts a schematic of an embodiment of stimulated regions for a consecutively fractured well at the start of a second hydraulic fracturing treatment.

[0020] FIG. 5C depicts a schematic of an embodiment of stimulated regions for a consecutively fractured well at the end of a second hydraulic fracturing treatment.

[0021] FIG. 5D depicts a schematic of an embodiment of stimulated regions for a consecutively fractured well at the end of pumping at the start of a third hydraulic fracturing treatment.

[0022] FIG. 6A depicts a schematic of an embodiment of stimulated regions for a zipper fractured well at the end of pumping after a first hydraulic fracturing treatment.

[0023] FIG. 6B depicts a schematic of an embodiment of stimulated regions for a zipper fractured well at the start of a second hydraulic fracturing treatment.

[0024] FIG. 6C depicts a schematic of an embodiment of stimulated regions for a zippered fractured well at the end of a second hydraulic fracturing treatment.

[0025] FIG. 6D depicts a schematic of an embodiment of stimulated regions for a zipper fractured well at the end of pumping at the start of a third hydraulic fracturing treatment.

[0026] FIG. 7 depicts a schematic of an embodiment consecutive fracturing.

[0027] FIG. 8 depicts a schematic of an embodiment alternate fracturing.

[0028] FIG. 9 depicts a schematic of an embodiment zipper fracturing in two wells.

[0029] FIG. 10 depicts a schematic of an embodiment staggered fracturing in three wells.

[0030] FIG. 11 depicts a schematic of an embodiment staggered of zipper fracturing in four wells.

[0031] FIG. 12 is a graphical depiction of an embodiment of Initial Shut-In Pressures (ISIPs) values for a drilling pad.

[0032] FIG. 13 depicts a contour map for an embodiment of a horizontal stress contrast for a single fracture in a horizontal well.

[0033] FIG. 13B depicts a contour map for the horizontal stress contrast for an embodiment of three fractures in a horizontal well.

[0034] FIG. 14 depicts microseismic maps of the first three fracture stages of a well.

[0035] FIG. 15 is a graphical depiction of percentage Outcomes versus average treatment pressures in various wells in a drilling pad.

[0036] FIG. 16 is a listing of trace data for an embodiment of well fracturing.

[0037] FIG. 17 is a graphical depiction of changes in the local reservoir stress (S_{hmin}) versus lateral distance from a fracture.

[0038] FIG. 18 is a graphical depiction of changes in the local reservoir horizontal stress contrast ($S_{hmax}-S_{hmin}$) versus lateral distance from a fracture.

[0039] FIG. 19 is a graphical depiction of variation in local minimum principal stress versus distance in feet away from the well.

[0040] FIG. 20 is a graphical depiction of variation in local minimum principal stress versus a transverse distance away from the well.

[0041] FIG. 21 is a graphical depiction of change in the fracture width versus time.

[0042] FIG. 22 is a graphical depiction of changes in the local reservoir minimum principal stress (S_{hmin}) versus lateral distance from the fracture.

[0043] FIG. 23 is a graphical depiction of changes in the local reservoir horizontal stress contrast ($S_{hmax}-S_{hmin}$) versus lateral distance from the fracture.

[0044] FIG. 24 are contour maps depicting fracture closure on the minimum principal stress.

[0045] FIG. 25 is a graphical depiction of the effect of unpropped fracture closure on the minimum principal stress due to fluid leak-off and pressure depletion over time.

[0046] FIG. 26 depicts simulated microseismic maps for stages 4, 5 and 6 for an embodiment of a well undergoing zipper fracturing.

[0047] FIG. 27 depicts simulated microseismic maps for stages 4, 5 and 6 for an embodiment of another well undergoing zipper fracturing.

[0048] FIG. 28 is a graphical depiction of the trend of simulated ISIP values of versus fracture sequence of wells in a drilling pad.

[0049] FIG. 29 depicts simulated microseismic maps of stages 3 in an embodiment of two wells undergoing zipper fracturing.

[0050] 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

[0051] It is to be understood the invention is not limited to particular systems described, which may, of course, vary. It is also to be understood that the terminology used herein is for the purpose of describing particular embodiments only, and is not intended to be limiting. As used in this specification, the singular forms “a”, “an” and “the” include plural referents unless the content clearly indicates otherwise. Thus, for example, reference to “a core” includes a combination of two or more cores and reference to “a material” includes mixtures of materials.

[0052] The following description generally relates to systems and methods for treating hydrocarbons in the formations. Such formations may be treated to yield hydrocarbon products and other products.

[0053] “API gravity” refers to API gravity at 15.5° C. (60° F.). API gravity is as determined by ASTM Method D6822 or ASTM Method D1298.

[0054] 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.

[0055] A “formation” includes one or more hydrocarbon containing layers, one or more non-hydrocarbon layers, an overburden, and/or an underburden. “Hydrocarbon layers” refer to layers in the formation that contain hydrocarbons. The hydrocarbon layers may contain non-hydrocarbon material and hydrocarbon material. The “overburden” and/or the “underburden” include one or more different types of impermeable materials. For example, the overburden and/or underburden may include rock, shale, mudstone, or wet/tight carbonate.

[0056] “Formation fluids” refer to fluids present in a formation and may include gases and liquids produced from a formation. Formation fluids may include hydrocarbon fluids as well as non-hydrocarbon fluids. Examples of formation fluids include inert gases, hydrocarbon gases, carbon oxides,

mobilized hydrocarbons, water (steam), and mixtures thereof. The term “mobilized fluid” refers to fluids in a hydrocarbon containing formation that are able to flow as a result of thermal treatment of the formation. “Produced fluids” refer to fluids removed from the formation.

[0057] “Fracture” refers to a crack or surface of breakage within a rock. A fracture along which there has been lateral displacement may be termed a fault. When walls of a fracture have moved only normal to each other, the fracture may be termed a joint. Fractures may enhance permeability of rocks greatly by connecting pores together, and for that reason, joints and faults may be induced mechanically in some reservoirs in order to increase fluid flow. Examples of fractures include planar fractures and associated fractures, induced fractures, microfractures and the like.

[0058] “Heavy hydrocarbons” are viscous hydrocarbon fluids. Heavy hydrocarbons may include highly viscous hydrocarbon fluids such as heavy oil, tar, oil sands, and/or asphalt. Heavy hydrocarbons may include carbon and hydrogen, as well as smaller concentrations of sulfur, oxygen, and nitrogen. Additional elements may also be present in heavy hydrocarbons in trace amounts. Heavy hydrocarbons may be classified by API gravity. Heavy hydrocarbons generally have an API gravity below about 20°. Heavy oil, for example, generally has an API gravity of about 10-20°, whereas tar generally has an API gravity below about 10°. The viscosity of heavy hydrocarbons is generally greater than about 100 centipoise at 15° C. Heavy hydrocarbons may include aromatics or other complex ring hydrocarbons.

[0059] Heavy hydrocarbons may be found in a relatively permeable formation. The relatively permeable formation may include heavy hydrocarbons entrained in, for example, sand, or carbonate. “Relatively permeable” is defined, with respect to formations or portions thereof, as an average permeability of 10 millidarcy or more (for example, 10 or 100 millidarcy). “Relatively low permeability” is defined, with respect to formations or portions thereof, as an average permeability of less than about 10 millidarcy. One darcy is equal to about 0.99 square micrometers. A low permeability layer generally has a permeability of less than about 0.1 millidarcy.

[0060] “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 in or adjacent to mineral matrices in the earth. Matrices may include, but are not limited to, sedimentary rock, sands, silicities, 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 such as hydrogen, nitrogen, carbon monoxide, carbon dioxide, hydrogen sulfide, water, and ammonia.

[0061] “Hydraulic fracturing” or “fracing” refers to creating or opening fractures that extend from the wellbore into formations. A fracturing fluid, for example viscous fluid, may be injected into the formation with sufficient hydraulic pressure (for example, at a pressure greater than the lithostatic pressure of the formation) to create and extend fractures, open preexisting natural fractures, or cause slippage of faults. In the formations discussed herein, natural fractures and faults are opened by the pressure. A proppant may be used to “prop” or hold open the fractures after the hydraulic pressure has

been released. The fractures may be useful for allowing fluid flow, for example, through a shale formation, or a geothermal energy source, such as a hot dry rock layer, among others.

[0062] 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 another cross-sectional shape. The wellbore may be open-hole or may be cased and cemented. As used herein, the terms “well” and “opening,” when referring to an opening in the formation may be used interchangeably with the term “wellbore.” “Horizontal wellbore” refers to a portion of a wellbore in a subterranean hydrocarbon containing formation to be completed that is substantially horizontal or at an angle from horizontal in the range of from about 0° to about 15°.

[0063] Nomenclature

[0064] A =fracture face area of one wing of a bi-wing fracture, L^2 , m^2 .

[0065] C_L =leak-off coefficient, $L/t^{0.5}$, $m/s^{1/2}$ (unless specified otherwise).

[0066] cf =empirical convergence factor, dimensionless.

[0067] E =Young’s modulus, m/Lt^2 , Pa.

[0068] E_p =Average Young’s modulus of the pay zone, Pa (unless otherwise specified).

[0069] F =fracture.

[0070] f_s =fracture spacing, m (unless otherwise specified).

[0071] G =shear modulus, Pa (unless otherwise specified).

[0072] h_f =fracture half-height, m (unless specified otherwise).

[0073] K =dry bulk modulus, Pa (unless otherwise specified).

[0074] K_s =grain bulk modulus, Pa (unless otherwise specified).

[0075] K_r =reservoir bulk modulus, Pa (unless otherwise specified).

[0076] L_f =fracture half-length, m (unless specified otherwise).

[0077] M =Biot’s modulus, Pa (unless otherwise specified).

[0078] m_s =mass of proppant pumped per stage, kg (unless specified otherwise).

[0079] ϕ_f =porosity of proppant-filled fracture, dimensionless.

[0080] $\rho_p=\rho_s$ =density of proppant, kg/m^3 (unless specified otherwise).

[0081] ρ_f =density of fluid, kg/m^3 (unless specified otherwise).

[0082] p_c =bottom hole closure pressure, Pa (unless specified otherwise).

[0083] p_f =bottom hole fracture pressure, m/Lt^2 , Pa.

[0084] p_{net} =net closure stress, m/Lt^2 , Pa (unless specified otherwise).

[0085] p_{net}^k =net closure pressure for iteration number k, Pa (unless otherwise specified).

[0086] r_p =ratio of permeable area to total fracture area, dimensionless.

[0087] S_p =spurt loss coefficient, L , m.

[0088] t =time, t , s.

[0089] u_L =leak-off rate, L/t , m/s .

[0090] V_i =initial volume of one wing of a bi-wing fracture, L^3 , m^3 .

[0091] V =current volume of one wing of a bi-wing fracture, L^3 , m^3 .

[0092] Δx =distance from fracture, m (unless otherwise specified).

[0093] x_r =reservoir boundary in X-direction, m (unless otherwise specified).

[0094] y_r =reservoir boundary in Y-direction, m (unless otherwise specified).

[0095] z_r =reservoir boundary in Z-direction, m (unless otherwise specified).

[0096] α =Biot's stress coefficient.

[0097] w_{max} =maximum fracture width, m (unless specified otherwise).

[0098] w_{maxf} =final maximum fracture width, L, m.

[0099] w_{maxi} =initial maximum fracture width, L, m.

[0100] w_{maxk} =maximum fracture width for iteration number k, m (unless otherwise specified).

[0101] $\overline{w_c}$ =average current fracture width, L, m.

[0102] $\overline{w_i}$ =average current fracture width, L, m.

[0103] κ =opening-time distribution factor, dimensionless.

[0104] ν =Poisson's ratio, dimensionless.

[0105] ν_p =Average Poisson's ratio in the pay zone, dimensionless.

[0106] ϵ_{ij} =strain tensor, dimensionless.

[0107] δ_{ij} =Kröcker delta, dimensionless.

[0108] σ_{hmax} =maximum horizontal in-situ stress, Pa (unless otherwise specified).

[0109] σ_{hmin} =minimum horizontal in-situ stress, Pa (unless otherwise specified).

[0110] σ_v =vertical in-situ stress, Pa (unless otherwise specified).

[0111] σ_{ij} =stress tensor, Pa (unless otherwise specified).

[0112] σ_{yy} =stress in the direction perpendicular to the crack face, m/Lt², Pa.

[0113] σ_{xx} =stress in the direction parallel to the crack face, m/Lt², Pa.

[0114] σ_{hmin} =minimum horizontal in-situ stress, m/Lt², Pa.

[0115] τ =dimensionless closure time, dimensionless.

[0116] ξ =variation in fluid content.

[0117] q_i =fluid discharge vector, m²/s (unless otherwise specified).

[0118] k =intrinsic permeability, m² (unless otherwise specified).

[0119] μ =fluid viscosity, Pa·s (unless otherwise specified).

[0120] FIG. 1 depicts a schematic of an embodiment of producing hydrocarbons from a hydrocarbon formation. Production system 100 in hydrocarbon formation 102 may include well 104 and production facility 106. Well 104 may be drilled using horizontal drilling methods to create a wellbore that runs within and along hydrocarbon formation 102. Hydrocarbon formation 102 may be, in some embodiments, a shale formation. In some embodiments, well 104 is drilled such that the well runs perpendicular to the maximum horizontal in-situ stresses of hydrocarbon formation 102 to obtain better production of formation fluids from the hydrocarbon formation.

[0121] Formation fluids may be produced from fractures and pore spaces of hydrocarbon formation 102. In some embodiments, hydrocarbon fluid (for example, natural gas) is adsorbed in organic material included in the rock of hydrocarbon formation 102 (for example, in shale of a shale formation). As wellbore 104 runs through hydrocarbon formation 102, wellbore 104 may also run through fractures (not expressly shown) of the hydrocarbon formation. The formation fluids (for example, gas) in the fractures may enter well 104 and is produced at drilling rig 106. As formation fluid leaves the fractures of hydrocarbon formation 102, the fluids adsorbed on the organic material are released into the frac-

tures such that the adsorbed fluids may also be retrieved. As the number of fractures of hydrocarbon formation 102 that well 104 passes through increases, an amount of formation fluid that may be produced by production system 100 may also increase. Therefore, increasing the number of fractures in hydrocarbon formation 102 along well 104 may increase production of formation fluids from the hydrocarbon formation.

[0122] The number and/or size of fractures in hydrocarbon formation 102 may be increased using hydraulic fracturing. The fracture may be an existing fracture in the formation, or may be initiated using a variety of techniques known in the hydraulic fracturing art. The amount of pressure needed to extend and propagate the fracture may be referred to as the "fracturing pressure."

[0123] In some embodiments, hydrocarbon fluids are produced from hydrocarbon formation 102 from groups of wells without disassembling a rig and reassembling the rig at a new location. FIG. 2 depicts a production of hydrocarbon fluids from a hydrocarbon formation using a drilling pad. In FIG. 2, drilling pad 110 may include multiple wellbores (for example, 4, 5, 10, 20, etc.) that are horizontally drilled in different directions. As shown, drilling pad 110 includes wellbores 112, 114, 116, 118. Once a well is drilled, the fully constructed rig may be lifted and moved over to the next well location using hydraulic walking or skidding systems. For example, rig 106 may be moved from wellbore 112 to wellbore 114. Other methods of methods of moving or connecting the wells to the wellhead are contemplated.

[0124] To produce formation fluids from hydrocarbon formation 102, hydraulic fracturing may be done from any of wellbores 104, 112, 114, 116, 118. Fracture design parameters that may generate conditions for creating complex fractures in both sequential fracturing and alternate fracturing are known. After sufficient fracturing is performed, formation fluids may be produced from hydrocarbon formation 102.

[0125] In some embodiments, a consecutive fracturing sequence is used to form fractures from one or more horizontal wells. In other embodiments, zipper fracturing may be used to create fractures from one or more horizontal wells. In zipper fracturing, two parallel horizontal wells are fractured sequentially one fracture at a time while alternating between wells. Zipper fracturing may lead to larger microseismic volumes when compared to simultaneous fracturing or consecutive fracturing sequences. In the process of fracturing, proppant may be added to a large number of the fractures to inhibit the fractures from closing.

[0126] During fracturing in hydrocarbon formation 102, a large number of microseismic events in a region may occur. Most of the microseismic events are signatures of failure in the formation that result in induced fractures that usually do not contain proppant because the proppant is unable to flow into these thin fractures from the main hydraulic fracture. Microseismic data may be used to show that induced, unpropped fractures occur and extend spatially beyond the propped fracture in many unconventional reservoirs.

[0127] In some embodiments, propped fractures may lead to the formation of induced, unpropped fractures during the fracturing process. The presence of unpropped fractures may be demonstrated by both microseismic data and tracer data (breakthrough of tracer being observed well beyond the propped fracture length). The presence of unpropped frac-

tures may significantly increase the spatial extent of the microseismic volume (rock volume from which multi-seismic events are recorded).

[0128] Opening of fractures, both propped and unpropped, as well as the injection of high pressure fluid, may result in significant changes in the stress properties of a rock formation. Accordingly, subsequent fractures initiated from a horizontal well may deviate toward or away from the previous fracture depending on the stress reorientation caused by prior fractures. The stress reorientation may be a function of mechanical properties of the reservoir rock, fracture spacing, and the orientation of the previous fracture. An induced stress shadow may affect the direction and extent of propagation of subsequent fractures. One consequence of the induced stress shadow is that later fracture stages tend to propagate into the open fracture networks of induced, unpropped fractures created earlier. Thus, the contribution of the subsequent fractures in hydrocarbon production may be reduced or minimized. Overlap of fractures may lead to a waste of “frac” fluid and proppant since the region being stimulated has already been stimulated earlier. Furthermore, interference between fractures in a given wellbore has been shown to depend on the stress shadow created by both the propped fracture and the induced unpropped fractures.

[0129] It has unexpectedly been found that if the time between successive fractures in a wellbore is increased long enough for the unpropped fractures to close, the stress shadow region shrinks leading to less interference between fractures and better performing fractures. Closure of the fractures may occur due to fracture fluid permeating the hydrocarbon formation (for example, “leaking-off” in to the hydrocarbon formation). Closure of the induced fracture network in time relaxes the stresses and the stresses no longer act as attractors for subsequent fractures. In addition, closure of the induced fracture network in time may lead to closure of the open pathways for flow.

[0130] Relaxation of the stresses and closure of the induced fractures may allow for more efficient fracture network coverage by successive fractures in a horizontal well. In some embodiments, the minimum time required for the unpropped fractures to close after the fracture has been pumped is at least 30 minutes, at least 45 minutes, at least 1 hour, at least 2 hours, at least 3 hours, or longer. In some embodiments, a minimum time required for the induced unpropped fractures to close is 45 minutes. For example, in fracturing a region of a hydrocarbon formation using a zipper fracturing pattern, the time between successive fractures is almost doubled as compared to the conventional consecutive fracturing of the same hydrocarbon formation region. In some embodiments, the time interval between adjacent fractures in a wellbore may have a significant effect on the production performance and geometry of fractures in a horizontal wellbore. During fracturing, some of the fractures may be treated with proppant. Open fractures (unpropped fractures) may be in fluid communication with one or more wellbores. Open fractures may also be in fluid communication with open fractures in the same or other wellbores.

[0131] Using controlled time-delay in fracturing, enhances drilling productivity as rig time in the field is not wasted. For example, zipper fractures are pumped, where the fractures are conducted in one well then the other starting with the toe of the well. Thus, time between fractures in a given well is increased substantially (by several hours). For example, in the “Texas Two Step” method (alternate fracturing method), frac-

turing fluid is pumped into fractures in a sequence of 1, 3, 5, 7, 9, 2, 4, 6, 8 rather than the sequence 1, 3, 2, 5, 4 with the numbers representing the sequence of the fractures along a well starting at the toe.

[0132] During or after fracturing treatments diagnostic tools may be used. In some embodiments, diagnostic tools are used to determine closure of fractures. Diagnostic tools include microseismic array, tiltmeter, or other diagnostic tools suitable for use analyzing the properties of a hydrocarbon formation.

[0133] In some embodiments, a geo-mechanical simulator is used to estimate the fracture closure time. To simulate the case of propped fractures, a uniform stress is applied along the face of a fracture to model the rock deformation due to the presence of proppant in the fracture. The stress is the sum of the net closure pressure in the presence of proppant, p_{net} and the minimum in-situ horizontal stress, σ_{hmin} . The uniform stress simulates the pressure inside a fracture at the instant of initiating the next fracture stage. For propped fractures, it is assumed that the pressure is equivalent to the pressure inside a fracture at its propped dimensions. The time required for the pressure to stabilize is generally much greater than the time between successive stages in a fracturing operation due to the low leak-off. Thus, the pressure value is not captured in the field, however, several methods exist to estimate the fracture closure pressure based on the initial shut-in pressure value. See, for example, Weng et al. “Equilibrium Test-A Method for Closure Pressure Determination. *SPE/ISRM Rock Mechanics Conference*, 2002.

[0134] The amount of proppant (for example, sand) pumped during a stage to estimate an ideal fracture width may be determined using Eq. (1). Equation 1 equation describes the mass of proppant required to fill up a Perkins-Kern-Nordgren (PKN) geometry fracture of prescribed length, height, porosity, and width at the wellbore. An iterative process to converge to the designed width at the wellbore by varying the net stress in the fracture may be performed.

$$m_s = \pi w_{max} L h_f (1 - \phi_p) \rho_p \quad (0)$$

[0135] The initial value of pressure inside the fracture may be estimated using the known analytical expression for a semi-infinite fracture (Eq. (2)).

$$p_{net} = p_c - \sigma_{hmin} = \frac{w_{max} E_p}{4(1 - \nu_p^2) h_f} \quad (0)$$

[0136] Equation 2 represents a theoretical value for a semi-infinite fracture, the obtained value may be an underestimation of the net closure pressure. The fracture net pressure may be varied based on Eq. (3) until the design fracture width, w_{max} the actual fracture width, w_{max}^k where k is the iteration cycle number.

$$p_{net}^{k+1} = p_{net}^k - \frac{1}{cf} \left(\frac{w_{max}^k - w_{max}}{w_{max}} \right) (p_{net}^k + \sigma_{hmin}) \quad (0)$$

[0137] A multi-layer model may be used, in which different mechanical properties are ascribed to the layers. The capability of allowing fracture height to traverse through multiple

layers is accounted for a multi-layer model. Using a multi-layer model, the pay zone height, and fracture height are assumed to be equal.

[0138] In some embodiments, the poroelastic properties of the material may be modeled. The coupled fluid-flow/mechanical isothermal response of a linear isotropic poroelastic material may be governed by known differential equations that relate pore pressure p , flux vector q_i , stress tensor σ_{ij} , strain tensor ϵ_{ij} , and the increment of fluid content ζ . In a poroelastic model, temperature is assumed constant and space and time derivatives are approximated using finite-difference schemes.

[0139] Fluid affects (volumetric response) may be described using three independent mechanical parameters (α , K and K_u). K is the drained bulk modulus, the bulk modulus of a porous material where fluid escapes without resistance ($p=0$). K_u is the undrained modulus corresponding to a zero flux material in which fluid cannot escape as a volumetric force is applied. The material's shear behavior is not influenced by the presence of fluid, and is thus described by the shear modulus G of the solid matrix.

[0140] Using a known continuum formulation where the fluid-filled porous material is treated as a whole, the constitutive equations of the poroelastic material relate the strain (ϵ_{ij} , ζ) and stress quantities (σ_{ij} , p) (Eqs. (4) and (5)):

$$\sigma_{ij} = 2G\epsilon_{ij} + \left(K - \frac{2}{3}G\right)\epsilon_{kk}\delta_{ij} - \alpha\delta_{ij}p \quad (4)$$

$$\zeta = \alpha\epsilon_{kk} + \frac{p}{M} \quad (5)$$

$$\text{with } \frac{1}{M} = \frac{\alpha - \phi}{K_s} + \frac{\phi}{K_f} \text{ and } \alpha = 1 - \frac{K}{K_s}$$

[0141] The constitutive equations contain two poroelastic quantities expressed in function of porosity Φ and bulk moduli K_s and K_f , Biot coefficient α , and Biot modulus M . Biot's coefficient α compares the material's deformation from the solid matrix and from the grains that compose the matrix. In the special case of incompressible solid constituents ($K_s \gg K$), Biot's coefficient takes the value 1. The inverse of the Biot modulus M is defined as the change in the rock's fluid content resulting from a change in pore pressure, for a constant volumetric strain (Eq. (6)).

$$\frac{1}{M} = \frac{\partial \zeta}{\partial p} \bigg|_{\epsilon_{kk}} \quad (6)$$

[0142] The fluid transport in the porous material may be modeled using Darcy's law of the fluid discharge in a porous material, derived from a Navier-Stokes equation (Eq. (7)):

$$q_i = -\frac{k}{\mu}(p_{,i} - \rho_f g_i) \quad (7)$$

[0143] Assuming that the equilibrium state is established at all times, the balance of local stresses in the fluid-filled porous material takes the form (Eq. (8)):

$$\sigma_{ij,j} + \rho g_i = 0 \quad (8)$$

where $\rho = (1-\phi)\rho_s + \phi\rho_f$

[0144] with ρ_s and ρ_f the densities of the solid and the fluid phase, respectively

[0145] When incorporating Eq. 6 into Eq. 8, the contributions of mechanical strains and pore-pressure gradients in the poroelastic equilibrium equations is solved at each grid-block of the numerical model (Eq. (9)):

$$\underbrace{2G\epsilon_{ij,j}}_{\text{stresses from mechanical strains}} + \underbrace{\left(K - \frac{2}{3}G\right)\epsilon_{kk,j}\delta_{ij}}_{\text{pore-pressure gradients}} - \underbrace{\alpha\delta_{ij}p_{,j}}_{\text{pore-pressure gradients}} + \underbrace{\rho g_i}_{\text{volumetric stresses}} = 0 \quad (9)$$

[0146] where p_j are the gradients in pore pressure along x_j

[0147] The PKN fracture geometry of interest may be modeled using a numerical code (for example, FLAC3D, obtained from ITASCA Consulting Group, Minneapolis, Minn., USA). Using a finite-difference and explicit-numerical scheme, the fluid flow and the stress state in the reservoir may be coupled. Poroelastic coupling may be determined based on Biot's theory (Eq. (6)). Parameters of the model include: a homogeneous, isotropic, purely elastic reservoir, bounded by layers with a different value of shear modulus, flow occurring within the reservoir and does not leak into the bounding layers, and bounding layers are defined as the top and bottom layers.

[0148] The far-field no-flow boundaries are located at a distance (from the fracture) equal to at least three times the fracture half-length L_f . The model boundary conditions are detailed below:

[0149] Uniform fluid pressure in the fracture: $p=p_f$ at $-L_f < x < L_f$, $y=0$, $-h_f < z < h_f$

[0150] Constant stress applied at outside boundaries: $\sigma_{zz} = -\sigma_v$, $\sigma_{xx} = -\sigma_{hmax}$ and $\sigma_{yy} = -\sigma_{hmin}$

[0151] No-flow reservoir boundaries at $x=\pm x_r$, $y=\pm y_r$, and $z=\pm z_r$.

[0152] Using the two models of a propped fracture and the poroelastic effects associated with a fracture, closure of an open fracture may be simulated. For example, simulation of closure of a fracture with proppant in it or the closure of an induced unpropped fracture. In an embodiment of a proppant-laden fracture, results from the simulation show that an open fracture converges to a fixed width due to the presence of the proppant. In an embodiment where no proppant in the opened fracture, results from the simulation show that the fracture closes completely or substantially closes.

[0153] Simulating the above physical processes uses a combination of the propped fracture model and the poroelastic model. The fluid pressure and the stress on the wall of the fracture may be used to iteratively to establish quasi-static equilibrium during the simulations. For fracture closure, initially a pressure that is higher than the closure pressure of the formation is used. After attaining mechanical equilibrium at the prescribed pressure, the poroelastic model is applied for a specific amount of time, which reduces the pressure inside the fracture. Mechanical equilibrium is attained using the new value of pressure, and iteratively continued with the above steps until the propped fracture width in the case of a closing propped fracture is attained or until the induced unpropped fracture closes completely. Using the simulation of a closure of an open fracture may allow better fracture sequences to be determined as compared to conventional hydraulic fracturing techniques known in the art.

[0154] In some embodiments, simulation of the mechanical stress interference between fractures in horizontal wells is performed. Simulation of the mechanical stress interference between fractures may be used to determine timing for hydraulic fracturing. The simulations may be derived from the coupling of the poroelastic and mechanical stress distribution equations described herein and the following fracture closure equations.

[0155] The Carter equation (Eq. 10) describes the leak-off rate as:

$$u_L = \frac{C_L}{\sqrt{t}}. \quad (10)$$

[0156] Using an overall material balance and combining Carter's concept, the change in volume of a fracture because of leak-off is known and a general form of the expression is given in Eq. 11.

$$V_i = V + 2A r_p (\kappa C_L \sqrt{t} + S_p) \quad (11).$$

[0157] In the absence of propagating fractures, the entire surface area of the fracture opens at the first moment of pumping and hence the maximum value of κ may be approximated to be about 2. Thus, the simplified expression for the variation in fracture volume is given by Eq. 12 below.

$$V = V_f - 4A C_L \sqrt{t} \quad (12).$$

[0158] Using a PKN like geometry, the volume of a fracture wing is the product of the average width and the face area. Thus, the variation in fracture width can now be expressed as:

$$\bar{w}_c = \bar{w}_i - 4C_L \sqrt{t} \quad (13).$$

[0159] In a PKN geometry fracture, the average width and maximum width are related by:

$$\bar{w} = 0.628 w_{max} \quad (14).$$

[0160] Thus, the fracture width at the wellbore varies with time as given by:

$$w_i = w_{i-\Delta t} - 6.37 C_L (\sqrt{t} - \sqrt{t - \Delta t}) \quad (15).$$

[0161] Eq. 15 may be adapted to a form in which the change in width between two time steps may be evaluated as shown:

$$w_i = w_{i-\Delta t} - 6.37 C_L (\sqrt{t} - \sqrt{t - \Delta t}) \quad (16)$$

[0162] where, Δt is the time step.

[0163] The discretization of Equation 15, enabled fluid and mechanical coupling in the fracture stress interference model.

[0164] In some embodiments, using the equations for estimating mechanical stress interference coupled with known analytical expressions for stresses around a penny shaped crack, the impact of fracture closure of long thin fractures on the stresses around the fractures may be determined. For example, a width of a penny shaped crack opened under uniform effective pressure is given by:

$$w_{max} = \frac{8(1 - \nu^2) p_{net} h_f}{\pi E}. \quad (17)$$

[0165] The penny crack is open due a net pressure given by p_{net} and the half height (or the radius) of the crack is given by h_f . Thus, the decrease in the width caused by fracture closure may be analytically coupled with the net pressure opening the

fracture, and hence the stress distribution around the crack. The reduced solution for the stresses along the axis perpendicular to the plane of the crack on the $z=0$ plane are presented below:

$$\sigma_{yy} = -\frac{2p_{net}}{\pi} \left[\frac{\xi(\xi^2 - 1)}{(\xi^2 + 1)^2} - \tan^{-1}\left(\frac{1}{\xi}\right) \right] \quad (18)$$

$$\sigma_{xx} = -\frac{p_{net}}{\pi} \left[\frac{3\xi}{(\xi^2 + 1)^2} + \frac{2\nu\xi}{(\xi^2 + 1)} - (1 + 2\nu)\tan^{-1}\left(\frac{1}{\xi}\right) \right].$$

[0166] In Equation 18, $\xi = y/h_f$ is the dimensionless distance along $(x, y, z) = (0, y, 0)$ away from the crack. The stresses may be plotted as dimensionless quantities versus the dimensionless distance from the crack. Eqs. 16, 18 and 19 may be combined and the obtained stress variation may be plotted as a function of time.

[0167] In some embodiments, the normalized stress perturbation is a function of square root of time. Eq. 15 shows that the width of the fracture decreases as the square root of time. Since the width of the fracture is proportional to the generated stress perturbation, the stress perturbation also decreases with the square root of time.

[0168] In some embodiments, increasing the leak-off coefficient decreases the closure time. Thus, in a very low permeability formation, the stress perturbation caused by the fracture at a particular distance from the fracture decreases much slower than in a higher permeability formation. Since, in the transient flow regime, the leak-off coefficient is a function of square root of permeability, the leak-off coefficient is inversely proportional to time. Thus, if the permeability of the formation decreases by 100 times, the leak-off coefficient increases by 10 times and the time of closure increases by 100 times.

[0169] In some embodiments, the stress interference in a formation due to formation of one or more fractures is a function of a number of variables. One variable is the time between consecutive fractures. A second variable is the distance between fractures. The normalized mechanical stress interference caused by a fracture is a function of time and distance from the fracture may be expressed in terms of the following dimensionless quantities:

$$\frac{\Delta\sigma_{yy}}{P_{net}} = (1 - 6.37\sqrt{\tau})f(\xi) \quad (19)$$

where,

$$f(\xi) = -\frac{2}{\pi} \left[\frac{\xi(\xi^2 - 1)}{(\xi^2 + 1)^2} - \tan^{-1}\left(\frac{1}{\xi}\right) \right],$$

$$\tau = \frac{t}{((w_{max} - w_{maxf})/C_L)^2}, \text{ and } P_{neti} = \frac{\pi E w_{maxi}}{8(1 - \nu^2)h_f}.$$

[0170] The relation presented above (Eq. 19) allows estimation of the time needed for the stress shadow to decay to an acceptable value. The estimated time will depend on various factors such as the fracture spacing, the elastic moduli, and so forth, which are represented in a dimensionless relation presented in Equation 19. FIGS. 3A, 3B, 4A and 4B are graphical depictions of data that may be obtained from Equation 19. In FIG. 3A, the data was plotted as a function of a closure of the fracture for a leak-off coefficient of $10^{-3} \text{ ft} \cdot \text{min}^{-0.5}$. Data 120

is at 0 minutes, data **122** is at 5 minutes, data **124** is at 10 minutes, data **126** is at 15 minutes, data **128** is at 20 minutes and data **310** is at 25 minutes. As shown in FIG. 3A, reducing the leak-off coefficient by 10 times increases the time of fracture closure by 100 times. In FIG. 3B, the data was plotted as a function of the closure of the fracture for a leak-off coefficient of 10^{-4} ft-min $^{-0.5}$. Data **132** is at 0 minutes, data **134** is at 500 minutes, data **136** is at 1000 minutes, data **138** is at 1500 minutes, data **140** is at 2000 minutes and data **142** is at 2500 minutes. As shown in FIGS. 3A and 3B, for the same leak-off coefficient, a change in initial width leads to a change in the fracture closure time.

[0171] FIGS. 4A and 4B are graphical depictions of the change in mechanical stress interference at various distances perpendicular to the fracture. In FIG. 4A, the initial maximum width of the fracture was set at 1 cm. Data **144** is at 0 minutes, data **146** is at 500 minutes, data **148** is at 1000 minutes, data **150** is at 1500 minutes, data **152** is at 2000 minutes and data **154** is at 2500 minutes. In FIG. 4B the initial maximum width of the fracture was set at 1 mm. Data **156** is at 0 minutes, data **158** is at 5 minutes, data **160** is at 10 minutes, data **162** is at 15 minutes, data **164** is at 20 minutes and data **166** is at 2500 minutes.

[0172] As shown in FIGS. 4A and 4B, the stress change in the bigger initial width case is much larger than the stress change in the smaller initial width case. The smaller initial width case may be more representative of induced unpropped fractures. Reduction in the leak-off coefficient and reduction in the initial width may cause the closure time to be the same for induced unpropped fracture as the main hydraulic fracture, however, the stress change because of an induced unpropped fracture is much lower than the stress change because of a hydraulic fracture. Thus, the impact of an induced unpropped fracture on the stress shadow of a hydraulic fracture network is insignificant or significantly insignificant. The closure time remaining the same, however, demonstrates that the induced unpropped fracture remains propped open for a long time. Thus, the induced unpropped fracture is still conducive for fluid flow. As shown in FIGS. 3 and 4, fracture closure over time leads to changes in the stress distribution around the fractures. As described herein, stress orientation is a time-dependent process and hydraulic fracturing in horizontal wells is affected by time in two ways: stress shadow and leak-off.

[0173] In some embodiments, the closure time of fractures in the field may be determined using the bottom-hole pressure data for the individual fracture stages. Unpropped fractures may close if the pressure inside the fracture decreases to the closure stress of the hydrocarbon formation. When the pressure inside an unpropped fracture attains a value equivalent to the closure pressure value of the formation, the unpropped fracture may close to a negligible width, which means that the fracture width/aperture is negligible. Thus, tracking the pressure inside a fracture after a fracture treatment provides an estimate of the fracture closure time. If bottom-hole pressure data is not available, surface pressure data (with appropriate corrections for friction drop and wellbore fluid head) may be used to obtain an estimate of the fracture closure time. If pressure for the individual fracture stages is not recorded after the fracture treatment, the fracture closure time obtained from diagnostic fracture injection tests (DIFT) or minifrac tests from the same hydrocarbon region as the well in consideration may be used as an estimate in designing the fracture treatment.

[0174] In some embodiments, closure of an open (induced, unpropped) fracture may be determined using pressure and/or permeability of the hydrocarbon formation. For example, the initial shut-in pressure value is measured at the wellhead. The pressure is monitored over time after the fracture treatment. Over the period of time, the pressure decreases. Advanced analysis may be performed (for example, using the algorithms described herein) on the pressure decay to estimate the closure pressure.

[0175] In embodiments where two or more wellbores are fractured during a fracturing process, spacing of the wellbores, type of fracturing (for example, consecutive, alternated and/or zipper), and the number of clusters may affect the initial shut in pressure and closure pressure of a fracture. Thus, determining a start time of fracturing based on the initial shut-in pressure or closure pressure may enhance the hydraulic fracturing process.

[0176] In some embodiments, unpropped fractures in some wells may be in fluid communication with other wells prior to closure of the fracture. For example, referring to FIG. 2, fractures from well **114** may be in fluid communication with fractures from well **118**, but the same fractures in well **118** may not be connected to well **114** or well **116** after a period of time. Thus, using time-delayed hydraulic fracturing to allow the fractures to close may inhibit loss of fracturing fluid and/or inhibit new fractures from interconnecting with previously formed fractures.

[0177] The creation of hydraulic fractures generally creates a network of induced unpropped fractures that are thin enough to not allow proppant entry. The network of induced unpropped fractures may close over time (since there is no proppant to keep them open), which may add significantly to the magnitude and the spatial extent of the time dependent stress changes that occur. The induced unpropped fracture network may initially span a large spatial area, which decreases over time. If the fracture treatment for the next stage is started before the areal extent of the induced unpropped fracture network has sufficiently receded, then overlap between the new and old induced unpropped fracture networks and sometimes between the new hydraulic fracture and old induced unpropped fracture network is likely. The overlap may cause excessive loss of fluid and proppant into the fracture network created by the previous stage. In order to avoid overlap, extra time allowed between successive stages in a horizontal well will allow the areal extent of the induced unpropped fracture network of the previous stage to recede. The recession of the induced unpropped fracture network may reduce the overlap between the stimulated volumes of the two consecutive stages and hence reduce the wastage of fluid and proppant.

[0178] FIGS. 5A-D depict schematics of embodiments of stimulated regions for consecutively fractured wells over a period of time. FIG. 3A depicts a schematic of an embodiment of stimulated regions for a consecutively fractured at the end of pumping after a first hydraulic fracturing treatment. FIG. 5B depicts a schematic of an embodiment of stimulated regions for a consecutively fractured at the start of a second hydraulic fracturing treatment. FIG. 5C depicts a schematic of an embodiment of stimulated regions for a consecutively fractured at the end of a second hydraulic fracturing treatment. FIG. 5D depicts a schematic of an embodiment of stimulated regions for a consecutively fractured at the end of pumping at the start of a third hydraulic fracturing treatment. In FIGS. 5A-D the time required to pump a fracture may be

represented by t_p . The time between the end of a treatment stage and the start of another treatment stage is represented by Δt . In some embodiments, Δt is constant at all times. In FIG. 5A, first fracture 170 in horizontal well 172 is initiated at a desired time (for example, $t=t_p$) such that area 174 is stimulated equals. In FIG. 5B, second fracture 176 in horizontal well 172 is initiated after a period of time (for example, $t_p+\Delta t$) such that an area around fracture 176 is stimulated. Comparing 5A with 5B, at the time second fracture 176 is initiated, stimulated area 174 has decreased in size. Over time, stimulated area 174 continues to decrease. As shown in FIG. 5C, at the end of the second hydraulic fracturing treatment stimulated area 178 created by the second hydraulic fracturing may be substantially oriented towards the adjacent (previous) area 174 and substantially overlaps with the fracture network of the previous area 204 as represented by area 180. At the time start (for example, $t=2t_p+2\Delta t$) of the third hydraulic fracturing treatment in the well stimulated area 174, stimulated area 178 and overlap 180 may be diminish in size as shown in FIG. 5D. As illustrated in FIGS. 5A-5D time between successive stages may influence the fracture network between successive fracture stages in a horizontal well.

[0179] FIGS. 6A-D depict schematics of embodiments of stimulated regions for consecutively fractured wells over a period of time. FIG. 6A depicts a schematic of an embodiment of stimulated regions for a zipper fractured well at the end of pumping after a first hydraulic fracturing treatment. FIG. 6B depicts a schematic of an embodiment of stimulated regions for a zipper fractured well at the start of a second hydraulic fracturing treatment. FIG. 6C depicts a schematic of an embodiment of stimulated regions for a zippered fractured well at the end of a second hydraulic fracturing treatment. FIG. 6D depicts a schematic of an embodiment of stimulated regions for a zipper fractured well at the end of pumping at the start of a third hydraulic fracturing treatment. In FIGS. 6A-D the time required to pump a fracture may be represented to t_p . The time between the end of a treatment stage and the start of another treatment stage is represented by Δt . In some embodiments, Δt is constant at all times. In FIG. 6A, first fracture 170 in horizontal well 172 is initiated to stimulate area 174 at a desired time (for example, $t=t_p$). In FIG. 6B, second fracture 182 in horizontal well 184 vertically displaced from horizontal well 172 is initiated at a desired time (for example, $2t_p+\Delta t$) to stimulate a second area 186. Comparing 6A with 6B at the time fracture 182 is initiated, stimulated area 174 has decreased in size. Over time, stimulated area 174 continues to decrease. Since fracture 182 is vertically displaced from first fracture 170, stimulated areas 174 and 186, do not significantly overlap. As shown in FIG. 6C, at the end of the second hydraulic fracturing treatment time (for example, $t=3t_p+2\Delta t$) stimulated area 178 created by a second hydraulic fracturing in well 172 may be substantially oriented towards the adjacent (previous) area 174 and does not substantially overlaps with the fracture network of the previous area 174. At the start of the third hydraulic fracturing treatment (for example, $t=2t_p+2\Delta t$) in the well stimulated area 174, stimulated area 178 and stimulated area 186 may be diminished in size as shown in FIG. 6D. As shown in FIGS. 6A-D, the increase in time allows the fracture network of the previous stage to close significantly, and hence reduces fracture interference and reduces the wastage of fluid and proppant into existing fracture networks.

[0180] In some embodiments, a method of fracturing a hydrocarbon formation includes using time-delayed hydraulic

fracturing in a drilling pad. Referring to FIG. 2, one or more first fractures may be propagated from wellbore 112 in hydrocarbon formation 102 using methods known in the field of hydrocarbon fracturing. Proppant may be added to a portion of the fractures during the fracturing process. Some of the fractures in the formation are too small for proppant and remain unpropped. During the fracturing process, the initial shut-in pressure of the wellbore 112 may be measured. The pressure may be monitored and when the pressure drops below a selected pressure or remains constant the fracture closure process is deemed complete. The pressure drop in wellbore 112 may be due to fluid permeating the hydrocarbon formation. The decrease in fluid pressure in unpropped fractures allows the fractures to close. The amount of time for the fracture to close may be minutes, hours, or days. For example, the period of time for fracture closure may be at least 30 minutes, at least 1 hour, at least 2 hours, at least 5 hour, or longer. After the unpropped fractures from wellbore 112 have closed, one or more second fractures from wellbore 112 and/or wellbore 116 may be propagated using hydraulic fracturing or other known methods of hydrocarbon fracturing. Wellbore 116 vertically displaced below or above wellbore 112 in the same region of hydrocarbon formation 102. For example, a net pressure in a wellbore may be greater 10,000 psi, 15,000 psi, or the like. Once the pressure drops to a desired pressure, propagation of the fracture in the wellbore and/or another wellbore may commence. In some embodiments, the pressure in a fracture wellbore is monitored while fracturing is initiated in another wellbore. The monitored pressure in the first wellbore may be used to determine closure of at least some fractures in the other wellbore. Thus, all closure data of all fractures in other wellbores may be obtained from one wellbore.

[0181] In some embodiments, wellbore 112 includes fracture stages at a desired distance (for example, 200 feet apart) while wellbores 114, 116, 118 have fracture stages at a different distance (for example, 300 feet apart). Due to the smaller fracture spacing, wellbore 112 may exhibit a high average initial shut in pressure (ISIP) as compared to the other wellbores. The decrease in fracture spacing may lead to increased mechanical interference between the stages and hence lead to higher pressure values required to pump the successive stages. Opening of a hydraulic fracture may cause mechanical stress interference in the vicinity of or proximate the hydraulic fracture. For example, an increase in a width of the hydraulic fracture may increase mechanical stress interference in the formation. Mechanical stress interference may cause a change in the stresses around the hydraulic fracture, which may directly impact the propagation direction of the successive hydraulic fractures.

[0182] In some embodiments, clusters of fractures per stage of fracturing from wellbores in hydrocarbon formation 102 may be propagated using known hydrocarbon fracturing techniques. In some embodiments, a number of clusters per stage is varied in various wells in the pad. For example, wellbore 112 may have 1 cluster per stage, wellbore 114 may have 4 clusters per stage spaced 75 feet apart, wellbore 116 may have 4 clusters per stage spaced 75 feet apart, and wellbore 118 may have 2 cluster per stage spaced 150 feet. The variations in the number of cluster spacing may lead to some significant changes in observed microseismic maps, and/or the observed treatment pressures. Increasing the number of clusters may lead to overlap of the microseismic events observed for each stage. The overlap in microseismic events

may suggest that the induced unpropped fracture networks of the two stages are overlapping. The average measured treatment pressures may be higher for single clusters than for multiple clusters. In some embodiments, creation of multiple propped fractures in a stage magnifies a region of re-orientated stresses. Using time-delayed hydraulic fracturing techniques described herein may decrease the stress field in the rock of the hydrocarbon formation, and thus, decrease the amount fractures propagated from a new stage of fracturing into fractures generated from an earlier stage of fracturing.

[0183] Various time-delayed fracturing schemes may be used to create fractures in hydrocarbon formation 102 from one or more wellbores (for example, wellbores 112, 114, 116, 118). A first fracture may be initiated in a wellbore of hydrocarbon formation 102. A selected period time is allowed to elapse so that at least a portion of the first fracture closes. At least one second fracture is propagated after the elapsed period of time. The second fracture may be between the first fracture and the toe of the wellbore. Alternatively, the second fracture may be between the first fracture and the heel of the wellbore. FIGS. 7-10 depict different types of hydraulic fracturing using time-delayed hydraulic fracturing. FIG. 7 depicts consecutive fracturing. In FIG. 7, fracture "1" is the first propagated fracture and successive fractures 2-8 are initiated one after another in a consecutive order. The sequence of fracturing is listed in TABLE 1, where tp is time of the initial shut-in pressure and Δt is time from the closure of the fracture, and Δs is the distance from the previous immediate fracture.

TABLE 1

Fracture Sequence	Treatment Start Time	Time After Previous Immediate Fracture	Distance From Previous Immediate Fracture
1	0	0	0
2	$tp + \Delta t$	$tp + \Delta t$	Δs
3	$2(tp + \Delta t)$	$tp + \Delta t$	Δs
4	$3(tp + \Delta t)$	$tp + \Delta t$	Δs
5	$4(tp + \Delta t)$	$tp + \Delta t$	Δs
6	$5(tp + \Delta t)$	$tp + \Delta t$	Δs
7	$6(tp + \Delta t)$	$tp + \Delta t$	Δs

[0184] FIG. 8 depicts alternate fracturing. In FIG. 8, two fractures may be initiated consecutively (e.g., fractures "1" and "2"), however the two previous fractures may be sufficiently far apart that a third fracture (e.g., fracture "3") may be initiated between the two previous fractures, such that the fractures alternate. The sequence of fracturing is listed in TABLE 2, where tp is time at initial shut-in pressure and Δt is time from the closure of the fracture, and Δs is the distance from the previous immediate fracture, and a for odd number of fractures (Nf) is $(Nf-1)/2$, and a for even number of fractures is $(Nf-2)/2$.

TABLE 2

Fracture Sequence	Treatment Start Time	Treatment End Time	Time After Recent Nearest Fracture (Delay Time)	Distance From Previous Nearest Fracture
1	0	tp	∞	∞
3	$tp + \Delta t$	$2tp + \Delta t$	Δt	$2\Delta s$
5	$2(tp + \Delta t)$	$3tp + 2\Delta t$	Δt	$2\Delta s$
7	$3(tp + \Delta t)$	$4tp + 3\Delta t$	Δt	$2\Delta s$
2	$4(tp + \Delta t)$	$5tp + 4\Delta t$	$2(tp) + 3(\Delta t)$	Δs
4	$5(tp + \Delta t)$	$6tp + 5\Delta t$	$2(tp) + 3(\Delta t)$	Δs

TABLE 2-continued

Fracture Sequence	Treatment Start Time	Treatment End Time	Time After Recent Nearest Fracture (Delay Time)	Distance From Previous Nearest Fracture
6	$6(tp + \Delta t)$	$7tp + 6\Delta t$	$2(tp) + 3(\Delta t)$	Δs
8	$7(tp + \Delta t)$	$8tp + 7\Delta t$	$3(tp) + 4(\Delta t)$	Δs

[0185] FIG. 9 depicts zipper fracturing in two wells (for example, wells 112 and 114 of FIG. 2). For a two well zipper fracturing, fracture 1 of well 112 and fracture 1' of well 114 are initiated sequentially, followed by fractures 2 of well 112 and fracture 2' of well 114, etc. The sequence of fracturing is given in TABLE 3, where tp is time at the initial shut-in pressure and Δt is time from the closure of the fracture, Δs is the distance from the previous immediate fracture.

TABLE 3

Well (Fracture) Sequence	Treatment Start Time	Treatment End Time	Start Time After Recent Nearest Fracture (Delay Time)	Distance From Previous Immediate Fracture (in same well)
112 (1)	0	tp	∞	∞
114 (1')	$tp + \Delta t$	$2(tp + \Delta t)$	∞	∞
112 (2)	$2(tp + \Delta t)$	$3tp + 2\Delta t$	$tp + 2\Delta t$	Δs
114 (2')	$3(tp + \Delta t)$	$4tp + 3\Delta t$	$tp + 2\Delta t$	Δs
112 (3)	$4(tp + \Delta t)$	$5tp + 4\Delta t$	$tp + 2\Delta t$	Δs
114 (3')	$5(tp + \Delta t)$	$6tp + 5\Delta t$	$tp + 2\Delta t$	Δs
112 (4)	$6(tp + \Delta t)$	$7tp + 6\Delta t$	$tp + 2\Delta t$	Δs
114 (4')	$7(tp + \Delta t)$	$8tp + 7\Delta t$	$tp + 2\Delta t$	Δs

[0186] FIG. 10 depicts staggered fracturing in three wells (for example, wells 112, 114, 116 of FIG. 2). The sequence of fracturing is given in TABLE 4, where tp is time at the initial shut in pressure and Δt is time from the closure of the fracture, Δs is the distance from the previous immediate fracture.

TABLE 4

Well (Fracture) Sequence	Treatment Start Time	Treatment End Time	Start Time After Recent Nearest Fracture (Delay Time)	Distance From Previous Immediate Fracture (in same well)
112 (1)	0	tp	∞	∞
116 (1)	$tp + \Delta t$	$2tp + \Delta t$	∞	∞
114 (1)	$2(tp + \Delta t)$	$3tp + 2\Delta t$	∞	∞
112 (2)	$3(tp + \Delta t)$	$4tp + 3\Delta t$	$2tp + 3\Delta t$	Δs
116 (2)	$4(tp + \Delta t)$	$5tp + 4\Delta t$	$2tp + 3\Delta t$	Δs
114 (2)	$5(tp + \Delta t)$	$6tp + 5\Delta t$	$2tp + 3\Delta t$	Δs
112 (3)	$6(tp + \Delta t)$	$7tp + 6\Delta t$	$2tp + 3\Delta t$	Δs
116 (3)	$7(tp + \Delta t)$	$8tp + 7\Delta t$	$2tp + 3\Delta t$	Δs
114 (3)	$8(tp + \Delta t)$	$9tp + 8\Delta t$	$2tp + 3\Delta t$	Δs

[0187] FIG. 11 depicts staggered zipper fracturing in four wellbores. Fracture 1 in well B, which corresponds to wellbore 114 in FIG. 2, is initiated followed by sequential fracturing in wellbore D (wellbore 118 in FIG. 2), well A (wellbore 112 in FIG. 2), and wellbore C (well 116 in FIG. 2). After the fracture in wellbore C is initiated, propagation of fracture 2 in wellbore B is started and so on. While patterns of fracturing are shown, others are contemplated. For example, a three well staggered alternate fracturing, four well staggered alternate zippered fracturing, and the like. The sequence of fracturing is given in TABLE 5, where tp is time at the initial

shut-in pressure and Δt is time from the closure of the fracture, Δs is the distance from the previous immediate fracture.

TABLE 5

Fracture Sequence	Treatment Start Time	Treatment End Time	Start Time After Recent Nearest Fracture (Delay Time)	Distance From Previous Immediate Fracture (in same well)
B1	0	tp	∞	∞
D1	tp + Δt	2tp + Δt	∞	∞
A1	2(tp + Δt)	3tp + 2 Δt	∞	∞
C1	3(tp + Δt)	4tp + 3 Δt	∞	∞
B2	4(tp + Δt)	5tp + 4 Δt	3tp + 4 Δt	Δs
D2	5(tp + Δt)	6tp + 5 Δt	3tp + 4 Δt	Δs
A2	6(tp + Δt)	7tp + 6 Δt	3tp + 4 Δt	Δs
C2	7(tp + Δt)	8tp + 7 Δt	3tp + 4 Δt	Δs
B3	8(tp + Δt)	9tp + 8 Δt	3tp + 4 Δt	Δs
D3	9(tp + Δt)	10tp + 9 Δt	3tp + 4 Δt	Δs
A3	10(tp + Δt)	11tp + 10 Δt	3tp + 4 Δt	Δs
C3	11(tp + Δt)	12tp + 11 Δt	3tp + 4 Δt	Δs

Examples

[0188] Non-limiting examples are set forth herein.

[0189] Simulation of Stress Interference:

[0190] A poroelastic simulation model built on FLAC3D was used to simulate the stress interference between fractures in horizontal wells. Geo-mechanical simulations of wells in a pad as shown in FIG. 2 were also simulated. The reservoir is modeled as a homogeneous, isotropic elastic and bounded medium to capture the stress distribution around the open fractures using the fracturing patterns depicted in FIGS. 8-11.

[0191] FIG. 12 is a graphical depiction of the Outcomes percentages versus the average treatment pressure in pounds per square inch for a fracture having a width of 1 centimeter. From the graphical data, the ascending order trend of the Initial Shut-In Pressures (ISIPs) four wells in a pad is shown. Outcomes are defined as the percentage of occurrence of the average treatment pressure on the X-axis. Pressure data 190 is for well A, pressure data 192 is for well B, pressure data 194 is for well C, and pressure data 196 is for well D.

[0192] Well A had a 200 ft. stage spacing while Well C had a 300 ft. stage spacing. Simulations run with different stage spacings indicate that closer well spacings led to an increase in net pressures and ISIPs. If the fractures were close enough to be in the stress reversal region, then the ISIPs decreased due to fracture intersection. Since fracture closure pressures were not recorded in the current data set, the Initial Shut-In Pressures were used as a surrogate for fracture closure pressures. The mean ISIP of the fractures in Well C is lower than the mean ISIP of the fractures in Well A. Well A has the smallest fracture spacing and hence the largest mean ISIP value.

[0193] FIGS. 13A and 13B depict the contour map for the horizontal stress contrast for (a) a single fracture in a horizontal well (FIG. 13A) and, (b) a case of three fractures in a horizontal well (FIG. 13B). The second case of three fractures was simulated to represent the field scenario of multiple clusters per stage. The same amount of proppant in the two simulations and we choose the outer fractures to have longer lengths than the middle fracture in the three fracture case. Further, it was assumed that all the fractures are propped and thus the geometries are fixed. As shown in from the data in FIGS. 13A and 13B, the spatial extent of the stress shadow in

the case of three fractures is increased as compared to the case of a single fracture. From the simulation, it was predicted that if multiple propped fractures are created in a stage then the region of re-orientated stresses were magnified.

[0194] Well A has one cluster per stage while Well C has 4 clusters per stage. From the simulation results, it was evident that if more fractures were activated in a stage, the stress shadows extend further along the well. In addition, the length of the fractures would be expected to be smaller when there are a greater number of clusters per stage. TABLE 6 contains the MicroSeismic (MS) volume averages of the various stages in the wells in the pad.

TABLE 6

Well	NE Length (ft.)	SW Length (ft.)	Network Width (ft.)	Length/Width
A6A	833	387	596	2.8
A6B	669	545	566	2.36
A6C	215	533	402	2.65
A6D	575	749	652	2.3

[0195] The MS arrays were located between wells B and C. The order of the wells from Northeast to Southwest was D, C, B, A. Thus, the MS arrays provide biased estimates of the Northeast and Southwest fracture lengths in the various stages. To overcome the location bias, the Length/Width ratio of the fractures in the various wells was used to compare the dimensions of the stimulated rock volume. Comparing the length-width ratio for the various wells, Well A had the highest ratio, followed by Well C, Well B, and Well D in that order. From the comparison, it was determined that Well A, which has only one cluster per fracture stage, has relatively long fractures, but the fractures do not have a very wide stimulated fracture network. This determination is consistent with the results obtained from the simulations (See, FIGS. 13A and 13B).

[0196] A greater relative width of the fracture network for Well C implied that significant overlap between the fracture networks induced by consecutive stages in Well C was present. FIG. 14 depicts microseismic maps of the first three stages of well A6C. In FIG. 14, the overlap in the microseismic envelopes of the first three stages of Well C are depicted. The overlap was reflected in the average treatment pressure recorded shown in FIG. 15. FIG. 15 depicts the ascending order of average treatment pressures in the various wells in the pad. Pressure data 200 is well A, pressure data 202 is well B, pressure data 204 is well C, and pressure data 206 is well D. It was assumed that the time between successive stages in Well C was not long enough to allow the opened fracture networks to close. These open fracture networks for the previous stages act as passages for flow when the current stage is treated. Thus, the resistance to flow is decreased because of the availability of conductive flow paths in the formation and hence the treatment pressures are decreased. FIG. 15, is a graphical depiction of the ascending trend of average treatment pressures recorded for the various stages in the wells. From FIG. 13, the trends that the average treatment pressure in Well C is considerably smaller than the average treatment pressure in Well A is shown.

[0197] Furthermore, tracer data depicts communication between wells B and D even though proppant had not propagated that far. One-way propagation of the fracture indicates that unpropped fractures are propagating from well D to B

(hence the tracer breakthrough) during the fracture treatment in Well D. The channel for communication shuts down as the fractures close after the fracture treatment is complete. No communication is observed from B to D (as indicated by tracer breakthrough). Tracer data is shown in FIG. 16

[0198] Simulation of Unpropped Fracture and Closure Time of Fractures.

[0199] The nature of the unpropped fractures and the time for closure of the fractures was simulated using FLAC3D and Equations 10-19.

[0200] FIG. 19 and FIG. 18 depict the poroelastic effects induced by a propped fracture. FIG. 19 depicts changes in the local reservoir stress (S_{hmin}) due to pressure depletion in a propped fracture. Data 210 is 1 hour, data 212 is 2 hour, data 214 is 3 hour, data 216 is 4 hours, data 218 is 5 hours, data 220 is 6 hours and data 222 is 7 hours. As shown in FIG. 19, the change in the local minimum principal stress along the axis of the wellbore decreases quickly with time as the pressure depletes. The fracture is located at 0 ft. in the chart. FIG. 18 depicts changes in the local reservoir horizontal stress contrast ($S_{hmax}-S_{hmin}$) due to pressure depletion from a propped fracture at 1 hour. The local reservoir horizontal stress contrast along the axis of the wellbore in the reservoir is small in regions affected by the pressurized fracture. The fracture is located at 0 ft. in the chart.

[0201] For a propped fracture, the initial pressure inside the fracture is assumed to be the fracture closure pressure. In the simulation, the fracture treatment time was 2 hours and for the duration of the treatment time, the fluid calculations in the matrix were done with a fixed fracture geometry and a constant pressure equivalent to the fracture closure pressure inside the fracture. Thereafter, the pressure inside the fracture was allowed to dissipate into the reservoir in time, as the pressure inside the fracture was greater than the reservoir pressure. The dissipation of pressure allowed simulation of fluid leak-off from the fracture into the reservoir. The fluid leak-off from the fracture increases the pressure, in the vicinity of the fracture, over time. Thus, giving rise to poroelastic effects and, hence, changing the stresses in the reservoir. As seen in FIGS. 19 and 18, a significant decrease in the minimum principal stress was observed in the immediate vicinity of the fracture. Thus, the variation in the minimal principal stress reduces very quickly away from the propped fracture.

[0202] FIGS. 19 and 20 depict the minimum principal stress in the reservoir due to the presence of a fractured well in the same pad in the reservoir. The fractured well has 10 transverse fractures spaced 300 ft. apart from each other. FIG. 19 depicts a variation in local minimum principal stress due to mechanical interference of fractures at a transverse distance away from the well. Pressure data 224 is at 440 ft. and pressure data 226 is at 880 ft. FIG. 20 depicts a variation in local minimum principal stress due to mechanical and poroelastic interference of fractures at a transverse distance away from the well. Pressure data 228 is at 440 ft., pressure data 230 is at 880 ft., pressure data 232 is at 1320 ft., and pressure data 234 is at 2200 ft. FIG. 19 depicts the influence of only the mechanical opening of the fractures while FIG. 20 depicts the influence of both poroelastic effects and mechanical effects.

[0203] The fracture half-lengths chosen in the simulations were 300 feet. Thus, the 440 ft. curve in the FIGS. 19 and 20 is only 140 ft. away from the tip of the fractures in the fractured well. Hence, the peaks on the curve correspond to the location of the fractures. Moving further away from the fractured well the influence of individual fractures on the

minimum principal stress is lost. In FIG. 19, all the curves beyond 440 ft. overlap each other, depicting the absence of any mechanical stress shadow effects at the respective distances from the fractured well. In FIG. 20, the simulations include poroelastic effects. The fractured well was simulated to represent a case wherein the horizontal well with 10 transverse fractures was completed and shut-in for 30 days in a high perm (10 mD) rock. Thus, the 30 days shut-in period would allow the pressure inside the propped fractures to dissipate into the reservoir. Pressure dissipation was attributed to the decrease in the minimum principal stress values away from the fractured wellbore.

[0204] From FIGS. 19 and 20, it is concluded that the stress shadow effect of the individual fractures (including both mechanical and poroelastic effects) do not extend beyond a distance greater than 440 ft. from the fractured well.

[0205] Simulation of Fracture Closure and Time Between Two Fractures.

[0206] A simulation of the influence of fracture closure and time between two fractures was simulated. Mechanical and poroelastic effects are taken into consideration in the simulation. The fracture was created by assuming an average treatment pressure value (12,000 psi). The in situ conditions were as follows: S_{hmin} 8700 psi; S_{hmax} was 8900 psi; reservoir pressure was 7750 psi; reservoir permeability was 1 mDarcy; reservoir porosity was 5%. FIG. 21 is a graphical depiction of maximum fracture width (mm) versus time (min). The average treatment pressure was higher than the pressure required to prop-open a fracture to the propped fracture width (as in FIGS. 19 and 18). Thus, the fracture was opened to a greater width than before due to the excess fluid pressure. As this fluid pressure decreases inside the fracture due to fluid leak-off, the fracture tries to close until it attains the final propped fracture width. The fracture treatment time was assumed to be 2 hours. During the fracture treatment time, the pressure inside the fracture was maintained at the average treatment pressure. In this simulation, the fracture closed from the fracture's initial width to the fracture's final propped width in about 110 minutes. The time of closure in the simulation was synthetic because the permeability assumed here was much higher than the permeability of the reservoir. However, time of closure has a similar order of magnitude as the fracture closure times observed in the field in mini-frac and DFIT tests.

[0207] FIG. 22 depicts changes in the local reservoir minimum principal stress (S_{hmin}) due to fracture closure and pressure mitigation from the closing fracture. The data shown is the value of the minimum principal stress along the axis of the wellbore in the reservoir. The fracture is located at 0 ft. in the chart. Data 236 is 10 at minutes, data 238 is at 30 minutes, data 240 is at 50 minutes, data 242 is at 70 minutes, data 244 is at 90 minutes, and data 246 is at 110 minutes. From FIG. 22, it is concluded that the change in minimum principal stress due to the open fracture is reduced in the vicinity of the fracture in time. The time shown in FIG. 22 is the time after the pumping of the fracture is stopped. FIG. 22 depicts that the decreasing width of the fracture over time quickly decreases the stress shadow in the vicinity of the fracture.

[0208] FIG. 23 depicts simulated results for changes in the local reservoir horizontal stress contrast ($S_{hmax}-S_{hmin}$) due to fracture closure and pressure mitigation from the closing fracture. The data shown in FIG. 23 is the value of the local reservoir horizontal stress contrast along the axis of the wellbore in the reservoir. Data 248 is at 10 minutes, data 250 is at 30 minutes, data 252 is at 50 minutes, data 254 is at 70

minutes, data **256** is at 90 minutes, data **258** is at 110 minutes. The fracture is located at 0 ft. in the chart. FIG. **23** shows the large effect of fracture closure on the horizontal stress contrast over time. In FIG. **23**, it is observed that the stress contrast decreases from about 1300 psi to about 200 psi at a distance of 100 ft. from the fracture in about 100 minutes. In addition, the region of almost negligible horizontal stress contrast shifts from about 450 ft. away from the fracture after 10 minutes to about 200 ft. from the fracture after 110 minutes. A high value of horizontal stress contrast could suggest the opening of unpropped fractures in Mode II or Mode III while a low value of horizontal stress contrast can enable the successive fractures to harness the heterogeneity of the reservoir in Mode I and allow the successive fracture to develop into a complex fracture network. Thus, considering the effect of fracture closure over time on the stress shadow is extremely significant when designing hydraulic fracturing treatments.

[0209] FIG. **24** are contour maps of the minimum principal stress in the reservoir that depicts the effect of fracture closure on the minimum principal stress. Regions **260** define the location of the initial unpropped open fractures. Line **262** represents the propped open fracture. The contours represent the local minimum principal stress. The computed effect of opening propped fractures and unpropped fractures on the in-situ stresses are shown. In the simulation, three fractures of different lengths at the same fracture pressure were initially created at a distance of 75 ft. from each other. The middle fracture was chosen to be longer and was assumed to be a propped fracture in the simulation, while the two outer fractures were assumed to be unpropped fractures. The propped fracture's geometry was held constant during the course of the simulation while the unpropped fractures were allowed to close over time in the simulation. The simulation represents simulating a field scenario in which the three clusters in a single fracture stage were stimulated. Alternatively, the simulation represents a propped fracture with two unpropped outer fractures created by shear failure in the reservoir. The middle fracture was assumed to offer the least resistance to fracture opening and thus was the longest and contains all the proppant. The outer fractures are assumed to have greater resistance to opening and thus were shorter and are assumed to not have any proppant. All the fractures were, however, assumed to open at the same fracturing pressure. The fracturing pressure was the fracture closure pressure for the propped fracture, but was considered as the initial pressure of the outer fractures. Once the fracture treatment was completed, the middle fracture retains the geometry but the outer fractures were allowed to close due to pressure dissipation and fluid leak-off.

[0210] As shown in FIG. **24**, the stress shadow of the unpropped fractures is reduced as time progresses. The presence of a large stress shadow may lead to fracture interference. Open, induced, unpropped fractures have a strong influence the direction of growth of subsequent fractures. However, as these fractures close, the stress shadow shrinks. Thus, it is advantageous to establish a time delay between two adjacent fractures.

[0211] FIG. **25** depicts the effect of unpropped fracture closure on the minimum principal stress due to fluid leak-off and pressure depletion over time. A middle fracture was located at 0 ft. and the outer fractures were located at -75 ft. and 75 ft. respectively. The middle fracture was three times the length of the outer fractures. FIG. **25** quantifies the contour plots of FIG. **24**. Data **264** is at 1.1 hours; data **266** is at

1.3 hours, data **268** is at 1.6 hours, data **270** is at 2.3 hours, data **272** is at 3.8 hours and data **274** is at 10.1 hours. Over the span of 10 hours that it takes to close the unpropped fractures, the minimum principal stress in their vicinity decreases from about 8300 psi to 7800 psi. As the unpropped fractures close over time, a significant (about 500 psi) drop in pressure is observed. The 500 psi decrease may be deemed sufficient to reorient successive fracture treatments that allow fractures to propagate in the shadow of the open fracture networks of the previous stage. Thus, the time between successive stages in a horizontal well may substantially change the interaction between spatially adjacent fractures in a wellbore.

[0212] In the simulation, Well A and Well C had consecutive fracturing sequences while Well B and Well D were zippered. Thus, the time between the consecutive fractures in Well C and Well A were smaller than the time between the consecutive fractures in Well B and Well D. The extra time in Well B and Well D allowed for the stimulated natural fractures to close and reduce the stress shadow in their vicinity. However, the induced unpropped fractures in Well A and Well C probably do not close when the next stage is stimulated. Thus, the fracture networks and stress shadows in Well A and Well C end up overlapping. The overlap is evident from the MS maps. The MS maps of Well B and Well D show minimal overlap and hence lead to greater fracture lengths as depicted in TABLE 6 and is also depicted in FIGS. **26** and **27**. FIG. **26** depicts microseismic maps for stages **4**, **5** and **6** for well A6B. FIG. **27** depicts microseismic maps for stages **4**, **5** and **6** for well A6D. As evident from the results, the microseismic scatter maps tend to stay confined within their respective stage dimensions in comparison to the patterns observed in FIG. **14**.

[0213] Another effect of the increase in time between consecutive fractures in well B and well D is the ISIP signature. FIG. **28** depicts the trend of ISIP values ($\Delta\sigma_{yy}/P_{net}$) of each stage in each well in the pad. The numbers on the X axis represent the fracture sequence number in the pad. The sequence numbers represent the order of fracturing in the pad. The values on the Y axis are in psi. Data **276** is well A, data **278** is well B, data **280** is well C and data **282** is well D. As discussed above, the stress shadow greatly impacts the closure pressure observed in consecutive stages in a horizontal well. Since well B and well D were zippered, the time between consecutive stages in both these wells was increased. Thus, any open fracture networks in the individual stages of these wells were assumed to have been given enough time to close. Thus, the effect of the stress shadow of the open fracture networks was lost when the consecutive stage in the either well was treated. This reduction in stress shadow leads to a reduction in the general ISIP value, and decreases the oscillation in the ISIP values. Well C, on the other hand, had less time between consecutive fractures, and, hence shows a characteristically high and oscillating ISIP trend.

[0214] The time between fractures and the closure of fracture networks can also be used to explain the tracer results on the pad. As depicted in FIG. **28**, many stages in well B show that they are connected to well D, however, surprisingly so, the same stages in well D do not seem to be connected to well B. The well connection may be explained by analyzing the microseismic maps of respective stages in the two wells. FIG. **29** depicts microseismic maps of stage **3** in well A6B and stage **3** in well A6D. Stage **3** in well B was stimulated before stage **3** in well D. Thus, at the time of end of treatment of stage **3** in well B a fracture network was created that may not be

connected to the well D. However, immediately after stage 3 in well B is completed, the treatment of stage 3 in well D is started. At the start of treatment of stage 3, the unproppped fracture network of stage 3 in well B is presumed to be open. Also, the induced unproppped fracture network of the corresponding stages in Well C was closed (since well C was the first well to be fractured and well B and well D were zipper fractured a few days after the completion of Well C). Thus, the fracture from well D intersected the pre-existing fracture network of well B, and under a favorable pressure gradient transports the tracer from well D to well B. If the time between the two stages discussed had been larger (allowing the unproppped fractures to close), there is a possibility that no tracer communication would have been observed. Thus, the tracer data confirms that there exists some induced unproppped pathways for fluid migration.

[0215] Further modifications and alternative embodiments of various aspects of the invention will 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.

What is claimed is:

1. A method of fracturing a hydrocarbon formation, comprising:

- propagating one or more first fractures from a first wellbore in the hydrocarbon formation;
- allowing a selected period of time to elapse so that at least some of the first fractures closes; and
- propagating at least one second fracture in the wellbore after the elapsed selected period of time.

2. The method of claim 1, wherein a desired amount of time is at least 30 minutes, at least 2 hours, or longer.

3. The method of claim 1, further comprising determining the closure of the fracture using diagnostic tools, wherein the diagnostic tools include microseismic array, tiltmeter, or the like.

4. The method of claim 1, wherein wellbore is an open wellbore.

5. The method of claim 1, wherein the wellbore is a cased wellbore.

6. The method of claim 1, wherein propagating at least one second fracture comprises determining a distance from the first fracture from the wellbore.

7. The method of claim 1, wherein propagating at least one second fracture comprises determining the pressure in the first fracture and determining a distance from the first fracture.

8. The method of claim 1, further comprising providing proppant to at least one of the first fractures.

9. The method of claim 1, wherein the closed first fracture is unproppped.

10. The method of claim 1, further comprising measuring initial shut in pressure associated with propagating the first fracture.

11. The method of claim 1, wherein at least one second fracture is propagated at a distance twice a determined distance from the initial wellbore.

12. The method of claim 11, further comprising propagating at least one third fracture, wherein propagating the third fracture comprises allowing at least one of the second fractures to close; determining a distance of the closed second fracture from the wellbore, wherein at least one third fracture is propagated at a distance twice the determined distance from the first fracture.

13. The method of claim 1, wherein propagating one or more first fractures and/or at least a second fracture comprises providing a fluid through one or more openings in the wellbore, wherein the fluid is pressurized.

14. The method of claim 1, wherein the second fracture is on either side of the first fracture.

15. The method of claim 1, wherein propagating the first and second fractures comprises zipper fracturing.

16. The method of claim 1, wherein propagating the first and second fractures comprises alternating fracturing.

17. The method of claim 1, wherein the closure of at least a portion of the fractures reduces the stress shadow of at least one of the initially created fractures.

18. The method of claim 1, further comprising using diagnostic tools during and/or after the fracturing treatments, wherein the diagnostic tools comprise microseismic array, tiltmeter, or the like.

19. The method of claim 1, further comprising providing proppant to at least some of the first fractures and/or second fractures, and producing formation fluid from at least some of the propped fractures.

20. The method of claim 1, wherein the second fracture is adjacent to at least one of the first fractures.

21. The method of claim 1, further comprising propagating at least one third fracture prior to propagating at least one second fracture, wherein the third fracture is propagated from a substantially horizontal second wellbore vertically displaced from the first wellbore.

22. The method of claim 1, wherein allowing a selected period of time is determined by:

$$\frac{\Delta\sigma_{yy}}{P_{net}} = (1 - 6.37\sqrt{\tau})f(\zeta)$$

where,

$$f(\zeta) = -\frac{2}{\pi} \left[\frac{\zeta(\zeta^2 - 1)}{(\zeta^2 + 1)^2} - \tan^{-1} \left(\frac{1}{\zeta} \right) \right],$$

$$\tau = \frac{t}{((w_{maxi} - w_{maxf})/C_L)^2}, \text{ and } P_{net} = \frac{\pi E w_{maxi}}{8(1 - \nu^2)h_f}$$

where $\Delta\sigma_{yy}$ is the stress in the direction perpendicular to the crack face, m/Lt^2 , Pa; p_{net} is the net closure stress, m/Lt^2 , Pa; τ is the dimensionless closure time; $f\zeta$ variation in fracture fluid content; ζ is fluid content; w_{maxi} is initial maximum fracture width and length in meters; w_{maxf} is final maximum fracture width and length in meters; C_L is leak-off coefficient in meters/second^{1/2}; E is Young's modulus, m/Lt^2 , Pa; and h_f is fracture half-height in meters.

23. The method of claim 1, further comprising propagating at least one fracture in a second wellbore; and determining closure of some of the second fractures by monitoring a pressure in the first wellbore.

24. The method of claim 1, propagating at least one third fracture in a second wellbore, wherein an initial time for fracturing the third fracture in a second wellbore is determined by monitoring a pressure in the first wellbore.

25. A method of fracturing a hydrocarbon formation, comprising:

propagating one or more first fractures from a wellbore in the hydrocarbon formation;

analyzing a pressure in the first fracture to determine closure of at least one or more of the first fractures;

propagating at least one second fracture from the wellbore or from a second wellbore based on the analyzed closure pressure; and

producing formation fluid from the hydrocarbon formation.

26. A method of fracturing a hydrocarbon formation, comprising:

propagating one or more first fractures from a wellbore in the hydrocarbon formation;

determining a minimum start time for propagating at least one second fracture from the wellbore and/or a second wellbore based on closure of at least some of the first fractures; and

propagating at least one second fracture from the wellbore based on the minimum start time, wherein the second fracture is at least a minimum spacing distance away from the first fracture.

27. A method of fracturing a hydrocarbon formation, comprising:

propagating one or more first fractures from a first wellbore of a plurality of wellbores in the hydrocarbon formation;

allowing, at least a desired period of time before propagating a second fracture at a chosen distance in the first wellbore, wherein at least some of the first fractures close during the period of time; and

propagating one or more second fractures from the same or a second wellbore in the hydrocarbon formation after fracture closure of at least some of the first fractures in the first wellbore, wherein the first wellbore and the second wellbore are in the same section of the hydrocarbon formation.

28. A method of fracturing a hydrocarbon formation comprising propagating at least one second fracture in a wellbore based on a closure of a first fracture in the hydrocarbon formation.

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