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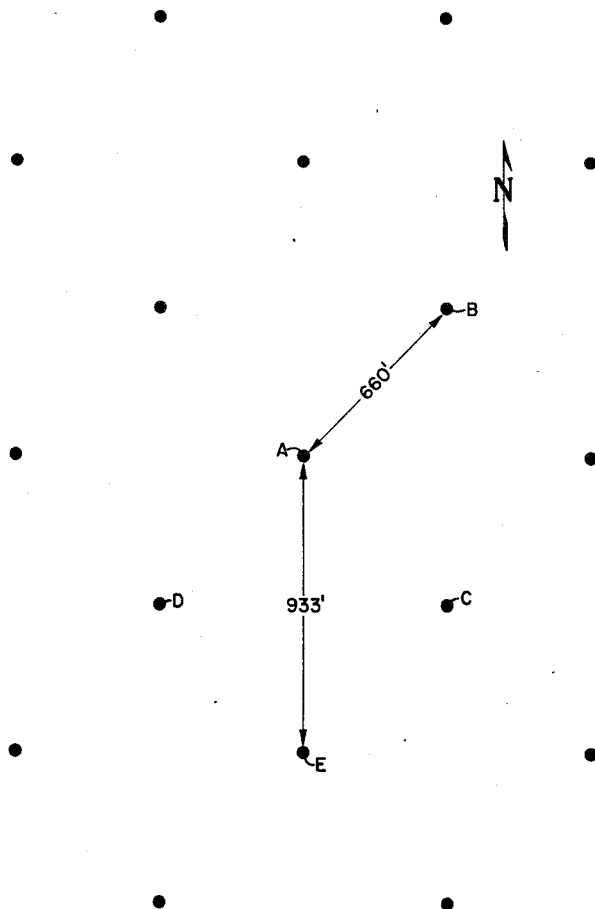
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[54] **DETECTING CHANGES IN ROCK PROPERTIES IN
A FORMATION BY PULSE TESTING**
11 Claims, 3 Drawing Figs.

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73/155, 166/271, 166/308
[51] Int. Cl. E21b 49/100
[50] Field of Search 166/250,
252, 254, 271, 308; 73/151, 152, 155

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ABSTRACT: A method of detecting induced changes in the rock properties of subterranean formations. The preferred use of the method is in determining the presence and orientation of induced fractures in the formation. In this use of this method, the formation is first pulse tested between the well to be fractured and at least one additional well. Preferably the pulse tests are conducted between the well to be fractured and at least three surrounding wells which are in noncollinear directions from the first well. The first well is then fractured and a second series of pulse tests between the fractured well and the other wells is conducted. The presence and orientation of the fracture can be determined by comparison of the pulse tests within the formation before and after fracturing.



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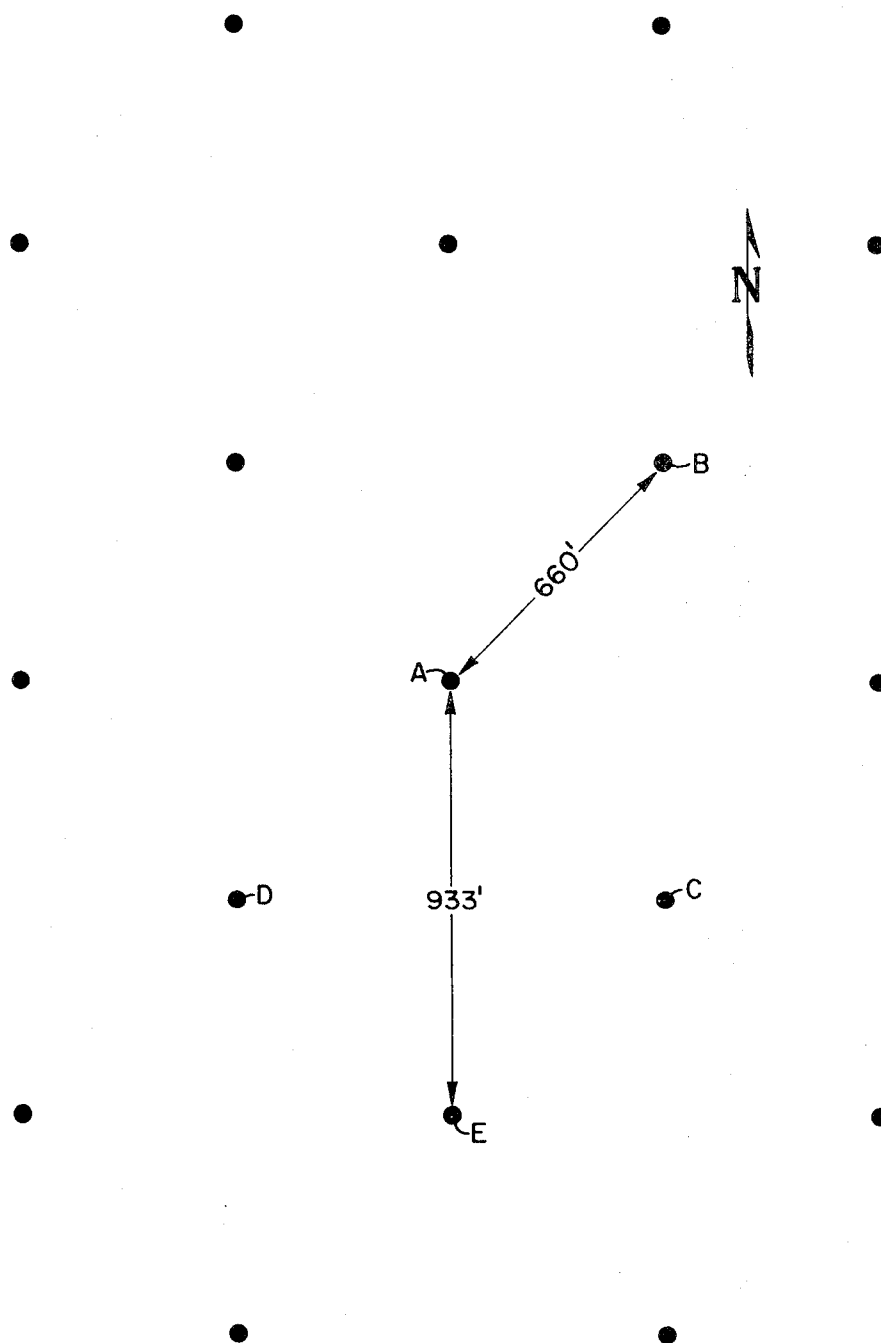


FIG. 1

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FIG. 2

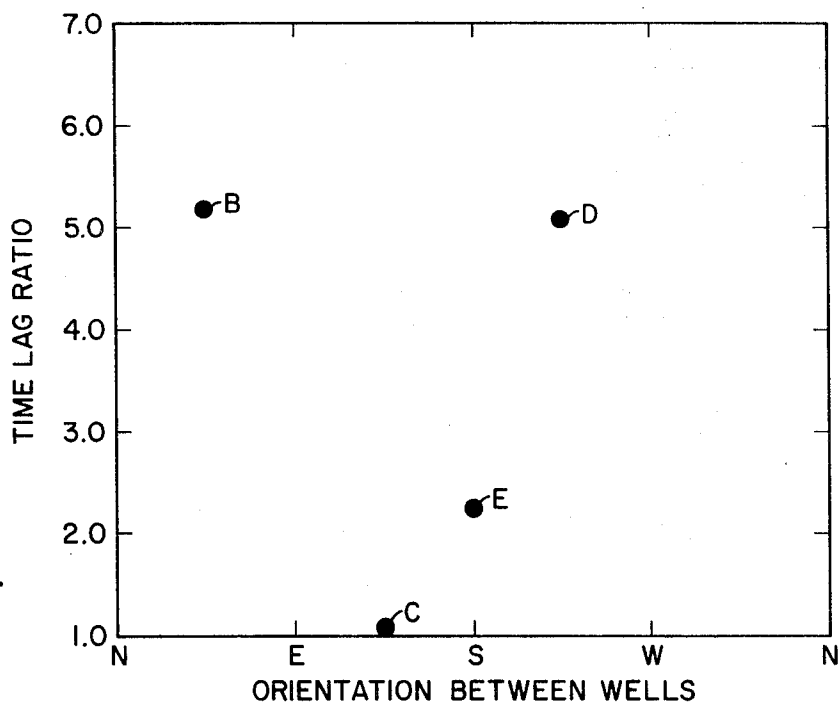
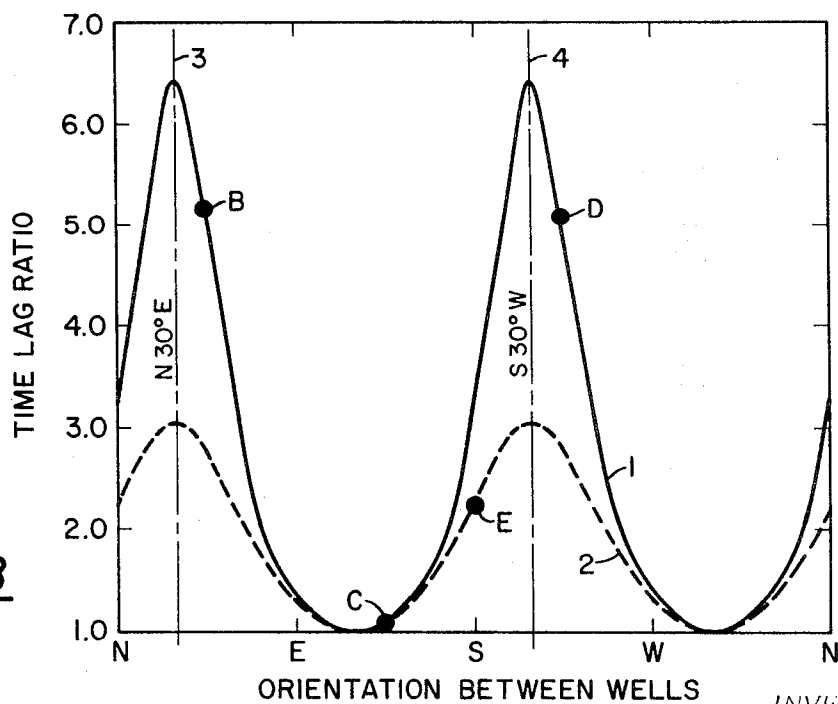


FIG. 3



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DETECTING CHANGES IN ROCK PROPERTIES IN A FORMATION BY PULSE TESTING

BACKGROUND OF THE INVENTION

1. Field of the Invention

This invention relates to a method of measuring and testing. More specifically, this invention relates to a method of formation logging to determine induced changes in the rock properties of the formation by pulse testing.

2. Description of the Prior Art

In recent years, hydraulic fracturing of a producing formation to increase the production of oil and gas has been used quite extensively and successively. Well fracturing is the splitting of rock under tension. When a rock is put under tension, it will stretch in proportion to the applied stress, up to its yield point; at which point, rock, being brittle, ruptures with little or no plastic deformation. In order to obtain a well fracture, hydraulic pressure is applied to the rock of the producing formation within the well bore, thus creating tensile force around the hole. As the hydraulic pressure increases, these tensile forces become great enough that they finally pull the rock apart and start the fracture or split which is lengthened by fluid being pumped into the hole. In other cases, the formation rock sometimes is not actually fractured because it already exists in a fractured state. In these cases, the fluid under hydraulic pressure must only overcome the confining stresses to open and extend the existing fractures.

To better study the effect of fracturing upon oil and gas recovery, it is necessary to know the nature and direction of such fractures. This is especially important in determining flow patterns and in determining the optimum method of producing oil from a formation. As the method of the invention is useful in determining the nature and extent of the fractures in a hydrocarbon-bearing formation, its importance to the recovery of oil and gas is immediately apparent.

The impression packer is one device which has been developed to determine the nature of induced fractures in a formation. This device has a resilient and deformable member which can be lowered into the well bore after fracturing. The resilient member is forced against the walls of the well bore by hydraulic or mechanical force and an impression of the well bore is imprinted on the deformable member. The device is then deflated and withdrawn from the wellbore. Visual inspection of the impressions made on this device reveals the general orientation of the fractures at the well bore. Such a device has a number of inherent drawbacks. First, it can only be employed in an uncased hole since it must contact the fractured formation. Second, the device reveals the nature and extent of the fracture only in the immediate vicinity of the well bore. The fracture may extend for hundreds of feet beyond the well bore; however, the impression packer by its very nature can only investigate the nature and extent of the fracture in a tiny fraction of this length. The induced fracture may also diverge radically from its orientation at the well bore, but the impression packer is ineffective in detecting such a divergence. Finally, unless auxiliary equipment is employed with the impression packer, the azimuth or direction of the fractures cannot be determined. As the packer is withdrawn from the hole, there is no assurance that it will remain in the same position it occupied at the formation. The operator therefore cannot relay with any degree of certainty on the relative position of the impressions on the packer when it is brought to the surface.

Pulse testing is a relatively new method for determining formation properties. Pulse testing involves the transmission of a sequence of transient pressure pulses in a formation by changing the rate at which fluids flow into or out of the formation through a well. The resultant changes in pressure with time are measured at another location in the formation to determine the formation properties. This method may be used in locating and evaluating reservoir heterogeneities such as faults, frac-

tures, permeability variations, changes in fluid saturations and the like. The present invention is an improvement on the basic pulse testing technique. The present invention isolates the effect of induced changes from other reservoir heterogeneities which may be present. It permits evaluation of the induced changes alone.

SUMMARY OF THE INVENTION

This invention relates to a method for detecting changes in formation rock properties by pulse testing before and after changing these properties. The primary use of the method is in determining the orientation of induced fractures. In practicing the method, the well to be fractured is first chosen and then pulse tests are conducted between that well and at least one other well. The well is then fractured and a second series of pulse tests is conducted. The pulse test results before and after fracturing determine the nature and extent of the induced fracture.

It is one of the objects of this invention to provide a method for determining the nature and extent of induced changes in rock properties within a subterranean formation. It is another object of this invention to determine the nature and extent of induced fractures in the formation.

The objects and nature of this invention will become more apparent from a discussion of the following drawings and preferred embodiment.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a plan view of a section of an oil field showing a portion of the wells in the field.

FIG. 2 is a graph of the orientation between pulsing and response wells versus the time lag ratio measured at each of the response wells.

FIG. 3 is the graph of FIG. 2 and illustrates a graphical method of determining fracture orientation.

DESCRIPTION OF THE PREFERRED EMBODIMENTS

The method of this invention may be used to determine the nature and extent of a variety of induced changes in reservoir rock properties. The following discussion, however, will be directed primarily to the preferred application of the method—determining the location and orientation of induced vertical fractures in a subterranean formation.

FIG. 1 is a plan view of a portion of an oil field. The field has been drilled with a regular pattern of wells in rows extending north-south and east-west. The distance between wells in each row is 933 feet. The alternate rows are offset so that the wells in that row are midway between the wells in the adjacent row.

As shown in FIG. 1, well A represents a well to be fractured. Well E is in the same north-south row and is located 933 feet due south of well A. Wells B and C are in the adjacent row to the east. These wells are 660 feet from well A in the directions N45°E and S45°E as shown in FIG. 1. Well D is in the adjacent north-south row to the west of well A. This well is 660 feet from well A in the direction S45°W.

In the practice of this invention, the formation is first pulse tested prior to fracturing well A. The precision of determining fractures orientation is dependent upon the number of well pairs that are tested. As will be described in greater detail herein, some information on fracture orientation can be determined by pulse testing between the well to be fractured and a single adjacent well before and after fracturing. However, in order to clearly define fracture orientation, it is preferred to pulse test between the well to be fractured and at least three offset, noncollinear wells. Wells are noncollinear in this sense when a line drawn between the wells does not intersect the well to be fractured. For example, wells B and C would be noncollinear. Wells B and D would be collinear, since a line drawn between these wells would intersect well A. It will generally be preferred to induce the pulse at the well to be fractured and to monitor the response at the surrounding wells. In this manner, one series of pulses from Well A can be

simultaneously measured at the offset wells. It should be recognized however that it is possible to conduct a pulse test in the opposite manner, with a series of pulses induced in the offset wells and the response measured at well A.

Following the initial pulse testing of the well pairs, well A is fractured, generally by hydraulic fracturing. The configuration of the induced fracture can be readily determined by techniques known to those skilled in the art. The fracture length, width, and fluid conductivity can be determined within reasonable accuracy using conventional analytical techniques.

At this point it should be noted that nearly all induced fractures in a subterranean formation are vertical. At one time it was felt that these fractures were predominantly oriented in horizontal direction. In recent years it has been found that this original conclusion is generally erroneous. Stress analysis of subterranean formations has shown that, in all except very shallow formations or unusual stress conditions, an induced fracture will lie in a vertical plane which intersects the well bore. Under induced stress, the formation will part against the least of the forces that are imposed on the formation. At even intermediate depths, the weight of the overburden becomes so great that the forces in a horizontal direction are the least and vertical fractures will be created when sufficient stresses are induced in the formation.

Following fracturing at well A, the pulse tests are repeated—preferably in the same manner as the first tests. The size of the induced pulses, the time length of the pulses, the time between pulses, and the direction of pulses should be the same before and after fracturing. It should be recognized, however, that it is possible to reverse the direction of the pulses if desired. For example, if prior to fracturing the pulses are induced at well B and received at well A, the direction may be reversed after fracturing and the pulses induced at well A and received at well B.

The physical properties which are measured during pulse testing include response amplitude and timelag. These properties are functions of the fluid diffusivity of the formation. It has been found that fracture orientation can be determined by simply comparing the timelags before and after fracturing. Timelag is defined as the time lapse in minutes between the change in flow rate which terminates a pulse and the maximum response amplitude measured at the response well which corresponds to that pulse.

The following table 1 gives the results of pulse testing between well pairs A-B, A-C, A-D, and A-E before and after fracturing well A.

TABLE 1

Pulsing Well:	Response Well	Distance Between Wells Ft.	Orientation Between Pulsing and Response Wells	Time Lag, Min.		Time Lag Ratio
				Before Fracturing	After Fracturing	
A.....	B	660	N45°E	54.0	10.4	5.19
A.....	C	660	S45°E	55.0	51.0	1.08
A.....	D	660	S45°W	56.5	11.1	5.09
A.....	E	933	S	105.0	46.7	2.25

It has been found that the timelag ratio (the timelag before fracturing divided by the timelag after fracturing) is a maximum when the fracture lies on a line between the pulsing well and the response well; it is a minimum when the fracture is perpendicular to a line between the wells. It can be seen from inspection of table 1 that the fracture is generally oriented toward wells B and D and generally perpendicular to a line between well A and well C. This is apparent from the radical change in timelag at wells B and D as shown by the high timelag ratio and by the relatively unchanged timelag at well C. This is perhaps more clearly shown in FIG. 2, where the timelag ratio at each well pair is shown as a function of the orientation between the pulsing well and the responding well. Thus, some indication of fracture orientation can be seen from the timelag ratio at a single well pair.

The information obtained can be used to define more precisely the orientation of the fractures if sufficient well pairs are tested. This method is a graphical analysis and requires a

minimum of three noncollinear responding wells. It has been found that the relationship between fracture orientation and timelag ratio can be reasonably approximated by the following two equations:

Equation 1
Time Lag Ratio = $\frac{1}{1 + \left(\frac{L_f}{r}\right)^2 - 2\left(\frac{L_f}{r}\right)\cos\theta}$ between the limits:
0° to α;
(180°-α) to (180°+α);
and (360°-α) to 360°

Equation 2
Time Lag Ratio = $\frac{1}{\sin^2\theta}$ between the limits:
α to (180°-α); and
(180°+α) to (360°-α)

where:
L_f=length of one fracture wing, ft,
r=distance between the fractured well and a well which forms a pulse test well pair with the fractured well, ft.
θ=angle between the fracture and a line between the fractured well and a well which forms a pulse test well pair with the fractured well, degrees.

$\alpha = \cos^{-1}\left(\frac{L_f}{r}\right)$

The application of this graphical method is perhaps best explained with reference to FIG. 3. The time lag ratio for each responding well is first plotted as a function of the orientation of that well from the pulsing well. An overlay curve is then produced by plotting the mathematical expressions of equations 1 and 2 between 0° and 360°. Conveniently on this overlay curve, the fracture is assumed to be positioned at 0° and 180°. Such a curve will be W-shaped with peaks at 0°, 180° and 360° and with minima at 90° and 270°. Since this mathematical expression is a function of the distance between the pulsing and responding wells, a separate curve must be derived for each well spacing. As shown in FIG. 3, curve 1 is derived for a well spacing of 660 feet; curve 2 is derived for a well spacing of 933 feet. These curves are then shifted over the timelag ratio-orientation plots until the best fit between data and curves is obtained. Note that the data points representing the 660 feet well spacing must correspond to curve 1, and that the data point representing the 933 feet well spacing must fit curve 2. When the best fit between data and curves is obtained, the peaks of the curve represent the orientation of the fracture; thus, as shown in FIG. 3 at lines 3 and 4, the fracture at well A is oriented at N30°E and S30°W.

The pulse test data may also be analyzed using conventional reservoir-modeling techniques. An example of one such technique is given in Jahns, "A Rapid Method for Obtaining Two-Dimensional Reservoir Description from Well Pressure Response Data," Society of Petroleum Engineers Journal, Dec. 1966, pp. 315-317. Such techniques are particularly suitable where the reservoir is strongly heterogeneous. In a homogeneous reservoir the ratio between timelag and the square of the distance between wells should be a constant. Where the pulse test results prior to fracturing show a wide variation in these ratios, reservoir-modeling should be employed. In the use of such reservoir-modeling techniques, the reservoir description obtained by pulse testing prior to fracturing may be rotated about the fractured well with the orientation of the fracture held constant. The best fit between the pulse test data obtained subsequent to fracturing and the results obtained by shifting the reservoir model will give the relative orientation of the fracture.

While this method has been described with reference to its primary use —the determination of vertical fracture orientation, it should be apparent that the method has broad applicability. The method may be used to detect a wide variety of induced changes in formation rock properties. As examples, but not limitations, the method may be used to determine the effect of increasing the formation pressure in a naturally fractured reservoir and whether the increased pressure has increased the fluid conductivity of these fractures. The method is also useful in determining the effectiveness of creating a permeability barrier at the oil-water contact of a well to reduce water coning. In such a use, the pulse tests would be conducted between vertically spaced points in the formation at a single well. The induced permeability barrier would, of course, lie between these vertically spaced points. Also the method can be used to determine the presence and extent of horizontal fractures.

We claim:

1. A method of testing a subterranean formation comprising:

- a. pulses testing between a plurality of locations within the formation by changing the fluid flow rate at at least one location in the formation and measuring the resultant change in pressure with time at at least one other location in the formation;
- b. then, changing the rock properties of the formation at one of said locations; and
- c. then, pulse testing a second time between the locations.

2. A method as defined in claim 1 wherein the locations are horizontally spaced in the formation at a plurality of wells.

3. A method as defined in claim 2 wherein the locations are at a first well and at least three noncollinear wells which are horizontally spaced about the first well.

4. A method as defined by claim 3 wherein the rock properties of the formation are changed by hydraulically inducing a fracture at the first well.

5. A method as defined by claim 4 wherein the pulse tests of steps (a) and (c) are in the same direction.

6. A method as defined by claim 4 wherein the pulse tests of steps (a) and (c) are in reverse directions.

7. A method as defined by claim 4 further comprising measuring the timelags of the pulse tests of step (a), measuring the timelags of the pulse tests of step (c), and determining the ratios of the timelags of step (a) to the timelags of step (c).

8. A method as defined by claim 7 further comprising comparing the timelag ratios and orientation of the other wells with respect to the first well to determine the presence and orientation of the induced fracture at the first well.

9. A method of determining the presence and orientation of hydraulically induced fractures within a subterranean formation comprising:

- a. pulse testing within the formation between a first well to be fractured and at least three surrounding, noncollinear wells by changing the fluid flow rate at least one of said wells and measuring the resultant change in pressure with time at the remaining wells;
- b. then, hydraulically fracturing the formation at the first well;
- c. then, repeating step (a);
- d. measuring the timelags of the pulse tests of step (a), measuring the timelags of the pulse tests of step (c), and determining the ratio of the time lags of step (a) to the time lags of step (c); and
- e. comparing the timelag ratios and orientation of the surrounding wells with respect to the first well to determine the presence and orientation of the induced fracture at the first well.

10. A method of testing a subterranean formation comprising:

- a. pulse testing between a plurality of locations within the formation by changing the fluid flow rate at least one location in the formation and measuring the resultant change in pressure with time at least one other location in the formation;
- b. then, changing the rock properties of the formation between at least two of said locations; and
- c. then, pulse testing a second time between the locations.

11. A method as defined in claim 10 wherein the locations are vertically spaced within the formation at a well.

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