A technique facilitates monitoring a reservoir property in a flowing well (22). The technique utilizes deployment of a sensor system (42,46) along the wellbore outside of a wellbore commingled flow region. The sensor system is utilized while the well is flowing during production, and the measured formation property can be used to determine/evaluate production and other well characteristics.
FIG. 3
METHOD FOR DETERMINING RESERVOIR PROPERTIES IN A FLOWING WELL

BACKGROUND OF THE INVENTION

1. Field of the Invention
   In a new, un-completed well, reservoir layer pressures can be measured using a wireline logging tool. This information is used by reservoir engineers to characterize the particular reservoir. However, once the well is completed and placed into production, the reservoir pressures change with time due to depletion of the reservoir intervals as a result of production. During production, reservoir layer pressures cannot be measured using a wireline logging tool. The present invention relates to a method for determining reservoir properties, including pressure, in a flowing well.

2. Description of Related Art
   Attempts have been made to calculate individual reservoir layer pressures in a flowing well by measuring a wellbore producing temperature profile obtained from the flowing production fluid within the wellbore. A thermal model is then used to estimate reservoir layer pressures required to produce the measured temperature profile. This method, however, relies on indirect measurement of individual reservoir layer pressures based on output from the thermal model.

BRIEF SUMMARY OF THE INVENTION

In general, the present invention provides a technique for monitoring a well. The technique utilizes deployment of a sensor system along the wellbore but outside the commingled flow region of the wellbore. The sensor system directly measures a reservoir property while the well is flowing during production. The measured property can be used to determine and evaluate production and other well-related characteristics.

BRIEF DESCRIPTION OF THE DRAWINGS

Certain embodiments of the invention will hereafter be described with reference to the accompanying drawings, wherein like reference numerals denote like elements, and:

FIG. 1 is an elevation view of a reservoir having a wellbore and a sensor system, according to an embodiment of the present invention;
FIG. 2 is a cross-sectional view of the wellbore illustrated in FIG. 1, according to an embodiment of the present invention;
FIG. 3 is a graphical representation of a reservoir property measured by the sensor system, according to an embodiment of the present invention;
FIG. 4 is a cross-sectional view of one embodiment of downhole equipment incorporating a sensor system, according to an embodiment of the present invention; and
FIG. 5 is a cross-sectional view similar to that of FIG. 4 but showing the downhole equipment positioned in a gravel pack, according to an embodiment of the present invention.

DETAILED DESCRIPTION OF THE INVENTION

In the following description, numerous details are set forth to provide an understanding of the present invention. However, it will be understood by those of ordinary skill in the art that the present invention may be practiced without these details and that numerous variations or modifications from the described embodiments may be possible.

The present invention relates to a technique for monitoring a well. Generally, a sensor system is deployed along a wellbore at or outside of a wellbore periphery, e.g., a wellbore wall defined by the original borehole or a surrounding surface of a gravel pack. In other words, the sensor system is deployed outside of a commingled flow region of the wellbore. This enables the direct detection and monitoring of a reservoir property via the sensor system while the well is producing.

According to one embodiment, individual layer reservoir pressures are directly measured in a multi-layered reservoir while the well is flowing. The direct pressure measurement is achieved by measuring the Joule-Thomson warming or cooling of a well fluid, e.g., oil or gas, caused by the pressure drop resulting from flow of the well fluid from the reservoir boundaries to the edge of the wellbore. In this embodiment, temperature sensors may be installed in the well and attached to or adjacent to the flowing reservoir sand face to measure the inflowing Joule-Thomson temperature rather than the wellbore flowing fluid mixture temperature. The difference between the inflowing Joule-Thomson temperature and the geothermal temperature of the reservoir at each point or reservoir layer is directly related to the difference between the flowing well pressure and the far reservoir pressure.

Use of a sensor system outside the wellbore commingled flow region, e.g., at or outside the wellbore periphery, enables the direct measurement of reservoir parameters, e.g., individual reservoir layer pressures, and the monitoring of changes in the parameter over time. Knowledge of individual reservoir layer pressures enables a reservoir engineer to monitor the depletion of the reservoir over time. Initially, reservoir pressure in individual reservoir layers can be measured with, for example, a wireline formation pressure measuring tool before the well is cased and completed. This technique and the initially measured pressure can be used to establish the geothermal temperature of the reservoir at its various layers. However, once the well is put into production, the wireline formation pressure measuring tool technique can no longer be used to directly measure individual reservoir layer pressures.

The non-flowing geothermal temperature of a given reservoir interval or layer remains constant. Accordingly, once this geothermal temperature is known, it can be used to determine relative temperature changes, and thus pressure drops, at various layers within the reservoir interval via the sensor system. When the well flows, the pressure drop resulting as fluid flows from the far reservoir into the wellbore causes the well fluid, e.g., oil or gas, to warm or cool according to the well defined Joule-Thomson relationship.

Placement of the sensor system close proximity to or outside the wellbore periphery enables the temperature sensor system to measure this inflowing Joule-Thomson temperature rather than the wellbore commingled flow temperature. By observing changes in temperature relative to the geothermal value along the wellbore in a flowing reservoir, and by knowing the flowing fluid thermal properties, the flowing reservoir pressures are directly determined from this relative temperature change. Over time, the cumulative changes in temperature allow the reservoir engineer to directly monitor changes in individual reservoir layer pressures and the corresponding depletion of the reservoir.
Referring generally to FIG. 1, one embodiment of the system illustrated in this embodiment, a well system comprises a well assembly disposed in a well having a wellbore drilled into a reservoir. Reservoir may have desirable production fluids, such as oil or gas. Well assembly extends downwardly into wellbore from, for example, a wellhead that may be positioned along a surface, such as the surface of the earth or a seabed floor. The wellbore may be formed as a vertical wellbore or a deviated wellbore.

In the embodiment illustrated in FIG. 1, well assembly comprises a tubular structure, such as a well casing positioned against the periphery of wellbore as defined by the surrounding sand face. In other embodiments, tubular structure may be a sand screen assembly positioned against wellbore as defined by a surrounding gravel pack. Tubular structure also may comprise other types of well equipment utilized in a producing well application and positioned proximate the periphery of the surrounding wellbore.

The illustrated tubular structure comprises a recess into which a sensor system is positioned, as further illustrated in FIG. 2. Sensor system may comprise one or more sensor lines that extend along tubular structure through at least the desired reservoir interval. Sensor lines may be designed to measure a desired reservoir parameter, e.g., temperature, on a multi-point or distributed basis along the desired reservoir interval. Recess, or other suitable mounting mechanisms, can be used to hold the sensor lines at or outside periphery of wellbore to enable direct determination of the reservoir parameter without being exposed to commingled fluid flow through an interior of tubular structure. Furthermore, the sensor lines may be coupled to an appropriate control system, such as a computer-based control system positioned at the surface or other suitable location, to collect, store and/or interpret data received from sensor lines.

By way of example, sensor system may be a temperature sensor system comprising a variety of temperature sensors, such as electrical temperature sensors, thermocouples, or optical fibers. In many applications, sensor system comprises a fiber optic distributed sensor system in which sensor lines are optical fibers able to make continuous temperature measurement along the reservoir. The optical fibers are positioned in close proximity with the periphery of wellbore so as to enable measurement of the flowing Joule-Thomson warmed/cooled well fluid temperature.

Referring generally to FIG. 3, a graphical representation is provided that illustrates the ability of sensor system to accurately measure a reservoir parameter, such as temperature. As illustrated, a geothermal temperature gradient is initially established across a plurality of permeable reservoir layers. In this example, reservoir layers are in a multi-layered sandstone reservoir containing hydrocarbon-based fluids.

The geothermal temperature gradient can be determined from the reservoir layer pressures initially obtained by, for example, use of a wireline formation pressure measuring tool before the well is cased and completed. As the well is flowed over time, the sensor lines measure and monitor changes in the Joule-Thomson temperature relative to the initial geothermal gradient along reservoir layers as indicated by graph line. The change in measured temperature occurring outside the commingled fluid flow directly indicates pressure changes due to the levels of depletion of well along reservoir layers. The reservoir pressure at a given point in time for a given reservoir layer or location along wellbore is obtained by multiplying the measured change in temperature by the Joule-Thomson coefficient for the particular fluid flowing from the reservoir. Joule-Thomson coefficients have been established for a variety of production fluids and are readily obtained, as known to those of ordinary skill in the art.

Referring generally to FIG. 4, an embodiment of tubular well equipment that can be combined with sensor system is illustrated. In this embodiment, tubular structure comprises a sand screen assembly that may be positioned within a gravel pack. By way of specific example, sand screen assembly may comprise a shunt-tube sand screen assembly. As illustrated, sand screen assembly comprises a tubular screen surrounded by a protective cover. A variety of components may be positioned between screen and protective cover, such as shunt tubes and gravel packing tubes.

In this embodiment, recess is formed in the exterior of protective cover to hold sensor lines at or outside the surrounding periphery defined by a gravel pack around screen. In the embodiment as illustrated in FIG. 5, the gravel pack also can be introduced into the interior of protective cover to place sensor lines outside of wellbore periphery as defined by the gravel pack. Thus, the sensor lines are positioned outside of the commingled fluid flow that moves through an interior of screen during production. According to one embodiment, sensor system comprises a distributed temperature sensing system utilizing one or more optical fibers held in recess by, for example, an encapsulant or other appropriate mechanism to secure the optical fibers in recess.

The effect of forming gravel pack in well is to fill the space between the original wellbore and screen with gravel. The gravel is packed and filled with reservoir fines once the well flows, thus causing the gravel pack to behave in the same manner as the reservoir itself. Accordingly, the sensors, e.g., optical fibers, are effectively installed outside of the commingled well fluid flow along the interior of screen.

In gravel pack applications, sensor system also can be used to determine the state, i.e., the effectiveness, of the gravel pack. When gravel pack is formed in well, the measured temperature normally reflects the Joule-Thomson inflowing temperature rather than the commingled flow temperature. With this knowledge, the output from sensor lines provides an indication of the effectiveness of the gravel pack. In applications where the gravel pack has been only partially completed, the Joule-Thomson temperature effect described above would not be evident in the poorly packed intervals. The inflowing fluid from the reservoir mixes or commingles with the flow from below in the annulus surrounding the sand screen. The data output from an ineffective gravel pack may resemble a thermal model mixture flowing temperature rather than a Joule-Thomson inflow temperature. With an effective gravel pack, however, sensor lines are able to measure a true Joule-Thomson temperature which is interpreted from the data output by sensor lines to control system.

It should be noted that other types of sand screen assemblies and other types of downhole well equipment can be utilized with sensor system to provide actual and direct
measurement and monitoring of a reservoir property. As described above, for example, sensor lines 42 can be installed on the outside of a cased and cemented reservoir interval provided care is taken not to perforate the sensor lines when the casing itself is perforated to enable flow from the surrounding formation. Additionally, a variety of sensors, including individual point sensors and distributed sensors, can be placed outside the commingled flow at or outside of wellbore periphery 36.  

[0029] The sensor system 40 can also be utilized in other types of well applications and/or to determine other reservoir properties. In any of these applications, the placement of the sensors outside the commingled flow enables direct determination of reservoir properties, e.g., direct determination of reservoir layer pressure by detecting the Joule-Thomson temperature changes. Accordingly, the determination and monitoring of reservoir properties can be achieved more accurately without inferring property values from modeling techniques or other indirect observation.  

[0030] Accordingly, although only a few embodiments of the present invention have been described in detail above, those of ordinary skill in the art will readily appreciate that many modifications are possible without materially departing from the teachings of this invention. Such modifications are intended to be included within the scope of this invention as defined in the claims.  

What is claimed is:  
1. A method of monitoring a well, comprising:  
deploying a sensor system along a wellbore outside a wellbore commingled flow region; and  
measuring a reservoir property with the sensor system while the well is producing.  
2. The method of claim 1, wherein measuring a reservoir property comprises directly determining individual reservoir layer pressures.  
3. The method of claim 1, further comprising utilizing the sensor system to determine the state of a gravel pack.  
4. The method of claim 2, wherein deploying the sensor system comprises deploying the sensor system at the periphery of the wellbore region defined by a surrounding gravel pack.  
5. The method of claim 2, wherein deploying the sensor system comprises deploying the sensor system outside of a well casing.  
6. The method of claim 2, wherein deploying the sensor system comprises deploying a fiber optic distributed sensing system.  
7. The method of claim 2, further comprising locating the sensor system in a groove along an exterior of a sand screen assembly to position the sensor system against a gravel pack.  
8. The method of claim 7, wherein locating the sensor system comprises locating the sensor system in the groove along the exterior of a screen cover in a slant tube sand screen assembly.  
9. The method of claim 7, wherein locating the sensor system comprises locating an optical fiber sensor in the groove.  
10. A method of monitoring a subterranean reservoir, comprising:  
directly measuring reservoir layer pressures along a wellbore in a reservoir by deploying a sensor system at or outside a wellbore periphery; and  
monitoring the reservoir layer pressures during production to determine depletion of reservoir intervals.  
11. The method of claim 10, wherein directly measuring reservoir layer pressures comprises measuring Joule-Thomson changes resulting from flow in the reservoir.  
12. The method of claim 10, wherein directly measuring reservoir layer pressures comprises deploying a multi-point sensor system.  
13. The method of claim 10, wherein directly measuring reservoir layer pressures comprises deploying a fiber optic distributed sensor.  
14. The method of claim 10, further comprising evaluating the quality of a surrounding gravel pack.  
15. The method of claim 10, wherein monitoring the reservoir pressure comprises continually monitoring cumulative Joule-Thomson changes to directly obtain reservoir pressure changes at multiple layers of the reservoir.  
16. The method of claim 13, wherein directly measuring reservoir layer pressures comprises locating the fiber optic distributed sensor in a groove along an exterior of a casing.  
17. The method of claim 13, wherein directly measuring reservoir layer pressures comprises locating the fiber optic distributed sensor in a groove along an exterior of a sand screen assembly to position the fiber optic sensor directly against a surrounding gravel pack.  
18. A method of monitoring a subterranean reservoir, comprising:  
determining a geothermal temperature of the reservoir at multiple depths along a wellbore;  
deploying a fiber optic sensor along the wellbore in the reservoir outside of a commingled flow region of the wellbore; and  
utilizing the fiber optic sensor to track changes in temperature relative to the geothermal temperature at the multiple depths along the wellbore during production.  
19. The method of claim 18, wherein deploying a fiber optic sensor comprises deploying a fiber optic distributed sensor.  
20. The method of claim 19, wherein deploying the fiber optic distributed sensor comprises locating the fiber optic distributed sensor in a groove along an exterior of a casing.  
21. The method of claim 19, wherein deploying the fiber optic distributed sensor comprises locating the fiber optic distributed sensor in a groove along an exterior of a sand screen assembly to position the fiber optic sensor directly against a surrounding gravel pack.  
22. The method of claim 18, wherein utilizing the fiber optic sensor comprises directly determining reservoir layer pressures based on the changes in temperature.  
23. The method of claim 18, wherein deploying the fiber optic sensor comprises deploying the fiber optic sensor along a gravel pack.  
24. The method of claim 23, further comprising evaluating the state of the gravel pack via data obtained from the fiber optic sensor.  
25. The method of claim 18, further comprising adjusting production of well fluid based on changes detected via the fiber optic sensor.