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A review on conceptual and practical oil and gas reservoir monitoring methods

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ABSTRACT

Reservoir monitoring is one of the key factors in the management of oil and gas resources. In particular, the evaluation of the Enhanced Oil Recovery (EOR) method through reservoir monitoring is crucial in EOR processes, where various fluids are injected into a reservoir to improve oil recovery. Reservoir monitoring methods enable engineers to conduct either direct or indirect surveillance to gather the required data. Depending on the objective of the monitoring program, a combination of two or more methods may need to be employed. However, in most cases, decisions are made based on the accessibility of the technology and the subsequent economic consideration. Therefore, selecting the most appropriate monitoring technique that would provide adequate data to meet the objective of the surveillance is critical with respect to EOR processes. The paper examines reservoir monitoring through a review of proposed, developed and implemented methods and techniques to enhance reservoir surveillance practices. Several methods, which range from well-established methods that are based on geophysical logging to emerging techniques that are derived from other fields of science and technology, are discussed. This review paper should serve as a reference to practicing engineers and researchers who aspire to improve the existing methods or develop new techniques. This review is divided into six sections based on the underlying principles of the monitoring methods. Real field application experiences are also included. At present, some of the methods that are discussed in the last section are mostly theoretical. However, these techniques may become routine with the advent of new technology and further research.

1. Introduction

Reservoir monitoring is one of the most important elements in oil and gas field management, providing industry experts with the required data to maximize hydrocarbon recovery. Comprehensive reservoir monitoring technology should be capable of recording changes in reservoir fluid saturations, measuring past and current locations of displacing fluid fronts, and subsequently predicting how these fluids will be distributed in the future (Breitenbach et al., 1989). A reliable monitoring method can directly dictate the success of enhanced oil recovery (EOR) processes by controlling and avoiding premature breakthroughs, estimating the effect of displacing fluids, defining the saturation distribution of both reservoir and non-reservoir fluids, and other benefits.

Traditionally, geophysical techniques have been used for reservoir description and delineation for many decades (Narayan and Dusseault, 1995). Currently, these techniques are used to actively monitor EOR processes. The detection of geophysical responses with time can help to estimate the lateral extent and volume of reservoirs that are affected by enhanced hydrocarbon recovery processes. Monitoring the conformance of displacing fluid is crucial to assess and predict the effectiveness of the injection method. Hence, in this context, the main objective of a monitoring technique is to provide a reliable description of the effectiveness of the displacing fluid propagation. The data that are obtained from monitoring a flooding process are complemented with production and observation well histories to estimate the reservoir recovery efficiency. Furthermore, these data are used to improve the planning of future continuations of production cycles. A number of techniques can be used to estimate the fluid distribution with respect to the displacing flood front location, for example, tracer injection (Omar et al., 2013), multifunctional downhole sensors (Saunders et al., 2008) and well fall-off tests (Ershaghi, 2008). Each method has its own advantages and disadvantages. The choice of a reservoir monitoring method depends on various factors, such as accuracy, consistency, cost effectiveness, installation procedures, etc. Some methods are designed for specific applications, whereas others can be used for general monitoring purposes.

This paper provides a review of recent advances in reservoir

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monitoring and surveillance. This review consists of conceptual and practical monitoring methods and techniques that have been developed and implemented in the industry. Each section is classified based on the technique that is employed in the reservoir monitoring. Generally, the monitoring techniques can be divided into geological and geophysical logging, remote sensing, tracer concentration monitoring, acoustic, and microseismic methods. In addition, techniques that are based on electromagnetic, streaming potential and seismoelectric data are discussed at the end of the paper, even though these methods are at various stages of implementation in the oil and gas industry. Some of these methods have been successfully used in other industries, for example, in mining and mineral exploration. Furthermore, this paper discusses the advantages and technical issues of each method. Therefore, this review paper intends to enhance the understanding of reservoir monitoring methods and their relevance in the petroleum industry.

2. Reservoir monitoring based on logging

2.1. Distributed Temperature Sensing (DTS)

A characteristic thermal gradient signature is created when fluid flows in or out of a wellbore (Denney, 2012). For example, fluid flows from high-pressure reservoirs into the wellbore during production. The recovery of liquid fluids produces a warming trend in the wellbore, whereas gas recovery produces a cooling effect. Such basic characteristics help to determine liquid and gas movements by using distributed-temperature sensing (DTS). DTS technology is based on a fiber-optic-distributed temperature-monitoring system that provides a series of continuous temperature measurement profiles along the wellbore length. No cable movement is required and measurements are taken by the fiber-optic cable, so many temperature surveys can be conducted for a given period.

Zonal coverage and fluid placement are equally important for scale-inhibitor squeeze treatments, matrix-acidizing treatments, water-control treatments, water injection for enhanced recovery, and hydraulic-acidizing and production profiling. Therefore, controlling the placement of the injected fluid is critical. Traditional surface-pressure monitoring, however, fails to determine if a treatment was executed effectively because the surface-pressure measurement can be masked by the friction factor. Hence, the surface pressure is not a valid indicator for what occurs downhole (Denney, 2012).

Glasbergen et al. (2010) proposed applying DTS to monitor fluid-diversion operations based on the real-time temperature profile variations along the wellbore. A comparative analysis of temperature profiles over a certain period can provide direct insight into the distribution of the injected fluid at the wellbore, and the data that are acquired from DTS can be interpreted both quantitatively and qualitatively. While the qualitative analysis utilizes color maps and visualizing techniques as tools for multiple temperature profiles in a single plot, the quantitative analysis relies on the calculation of the injected fluid distribution that exits the wellbore. An example of the quantification process is shown in Fig. 1. The color shades represent temperature variations from 30 °C (blue) to 41 °C (red). The wellbore diagram of the injection well is shown on the left-hand side of Fig. 1. The different gradients on the color map represent temperature anomalies that are caused by a disturbance, i.e., fluid injection, where the gradients are a function of the fluid velocity.

Glasbergen et al. (2010) presented several cases where DTS was successfully applied to both quantitatively and qualitatively monitor and assess the effectiveness of chemical diverters, such as in-situ-cross-linked acids (ICA), rock-salt particulates and relative permeability modifiers (RPM), for matrix-acidizing treatments. The applicability range of DTS is not restricted to the above fluid diverters. However, these authors argued that the DTS-monitoring technique does not have a general application. Therefore, we must conduct a candidate-selection process to meet the DTS requirements to achieve the best results. Fig. 2 provides a flow chart that is used for candidate selection. DTS numbers greater than 2.5 are appropriate candidates for DTS monitoring. The dimensionless DTS number N_{DTS} is calculated by using Eq. (1) below:

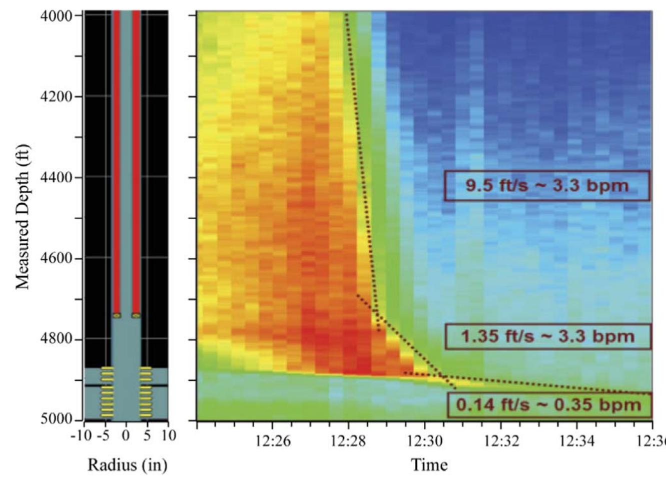

Fig. 1. Color map of velocity changes (Glasbergen et al., 2010).

$$N_{DTS} = \frac{ID^2 \cdot h}{C \cdot T_{DTS} \cdot Q_{BH}} \tag{1}$$

where ID is the inner diameter of the completion in inches, h is the total measured length of the completion in feet, C is a unit conversion constant of 17.1582, T_{DTS} is the data acquisition time between two consecutive DTS profiles in seconds, and Q_{BH} is the bottom hole injection rate in barrels per minute.

Recently conducted field studies showed that digital flow profiles that are obtained with DTS can help to determine distributed flow allocations in production and injection wells, improved the production and sweep efficiency (Kluth and Naldrett, 2009). Furthermore, DTS has also demonstrated exceptional performance and long-term reliability in horizontal and advanced well completions. Denney (2013) claims that DTS can be used to gather information regarding which layers are flooding effectively and which layers are not. For example, DTS was applied to monitor one of the world's largest steam-flood operations that was conducted on Sumatra island in Indonesia (Nath et al., 2005). The field management significantly benefited from the DTS surveys, which improved the understanding of breakthrough zones along the target pay interval of production wells. Moreover, the surveys also helped to identify bypassed or unswept oil zones in the steam-flood patterns.

DTS surveys are extensively used in the petroleum industry. Denney (2007) discussed several successful applications of DTS for various field projects. In particular, we highlight the case study that discusses how continuous temperature monitoring helped to increase the efficiency of the electrical submersible pump (ESP) design. Hydraulic fracturing operations that use DTS real-time monitoring have also grown popular thanks to this method's effectiveness in estimating the fracture initiation depth, number of produced fractures and vertical coverage. Sierra et al. (2008) analyzed transient DTS data that were obtained during multi-stage and high-rate hydrofracturing in vertical, deviated and horizontal petroleum wells. Furthermore, these authors discussed the advantages and limitations of installing fiber cables by hanging inside casing and cementing them behind the casing based on the type of well, length of the gross pay zone, fracture design, treatment rate, and type of fluids.

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