Integrating Advanced Production and Image Logging in a High-GOR Horizontal Well

Production logging in high gas/oil ratio (GOR) horizontal wells is difficult because of complicated multiphase-flow regimes in long undulating wellbores. Accurate diagnosis of gas-entry points is important to understand well performance and the reservoir dynamics and characterization and, if possible, to plan remedial shutoff action. This paper summarizes a case study of a high-GOR horizontal well from which oil production decreased significantly because of gas entry. An integrated production-logging tool was used to detect gas-entry points and determine the flow profile.

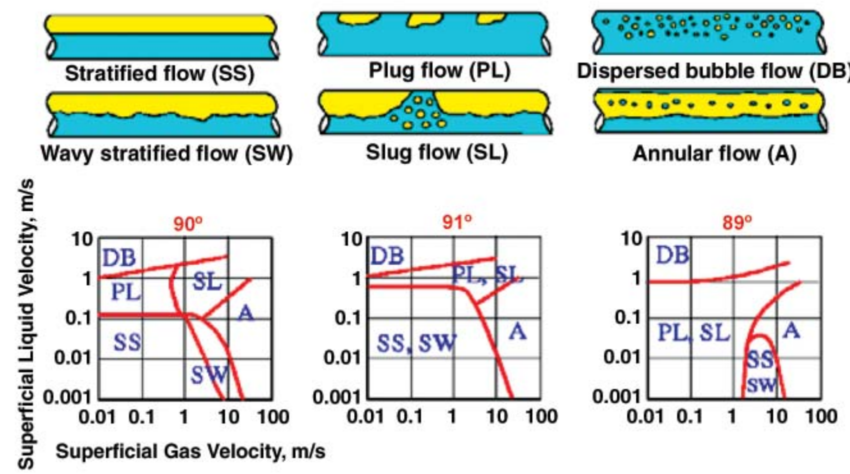

Fig. 1—Gas/liquid flow regimes.

Introduction

Increased gas production can reduce oil-well performance significantly. Generally, a drop in reservoir pressure or gas breakthrough could cause an increase in GOR. Detecting gas-entry intervals, in the case of early increases in GOR, provides valuable information for understanding reservoir dynamics and optimizing well placement. Well-performance evaluation is crucial for maximum productivity and choosing well trajectories. The integration of reservoir and geological data yields a more accurate characterization.

Conventional production-logging tools, developed for vertical wells, often do not perform well in horizontal wells because multiphase flow in horizontal sections is highly segregated. In this case, high-GOR production began during the first year. Detection of gas-entry intervals was the primary objective. An integrated production-logging tool string, including a gas-holdup optical-sensor tool, was run. The tool detected gas and oil entry accurately. The integration with static data from openhole and image logs showed coherent results by identifying high- and low-permeability facies where the gas entries were observed from high-permeability zones crossing the wellbore. A fine-grid numerical-simulation model was developed with a commercial simulator to assess remedial-action plans.

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 93473, "Integration of Advanced Production and Image Logging in a High-GOR Horizontal Well With Assessment of Remedial Actions," by ***A.A. Al-Fawwaz,*** *SPE, and* ***H.K. Mubarak,*** *Saudi Aramco, and* ***M. Zeybek,*** *SPE, Schlumberger Oilfield Services, prepared for the 2005 SPE Middle East Oil & Gas Show and Conference, Bahrain, 12–15 March.*

Gas/Liquid Flow and Integrated Production-Logging Tool String

It is known that, generally, oil/water flow regimes in horizontal wells are stratified. It is important that fluid-flow regimes be understood for interpretation and measurement accuracy. **Fig. 1** shows the flow regimes in horizontal wells having gas/liquid flow. Mostly stratified or wavy-stratified flow regimes are observed when the deviation is 90° or greater. However, the stratified-flow domain is limited when the deviation is less than 90°. Plug or slug flow becomes dominant at this deviation, indicating the complexity of the flow. Considering the small changes in well deviation and fluctuations in the well performance, real-time gas-holdup measurements during each pass would improve the results.

An integrated production-logging tool string for horizontal wells was developed to obtain quantitative determination of flow profiles. The integrated tool comprises a combinable production-logging tool (providing pressure, temperature, and spinner data) and separate tools to measure oil-phase velocity by use of a chemical marker; water velocity by use of a water-flow log; oil, water, and gas holdup by use of electrical probes; three-phase holdup by use of a pulsed-neutron tool; and wellbore dimensions by use of a wellbore caliper. Note that single-phase velocity measurement of oil is a direct measurement, requiring no calibration or correlation, and it is benchmarked in a flowloop. Several examples of integrated production logging in horizontal wells have been published. In this study, a new, shorter production-logging tool, provid-

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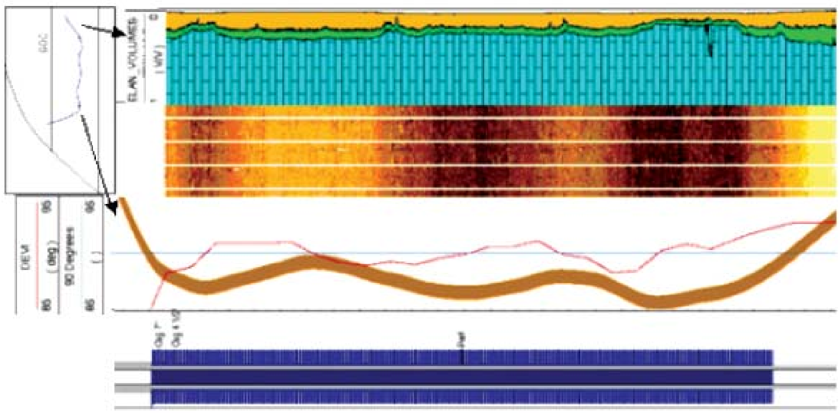

Fig. 2—Well trajectory with openhole formation-imaging-log data.

ing *x-y* caliper, spinner, and flow imaging in the same module, was used along with the previously mentioned sensors.

Although gas holdup also can be determined with a pulse-neutron tool, it is a one-pass measurement and requires further processing to obtain quantitative values. In liquid/gas flow regimes, obtaining real-time quantitative gas-holdup data in each pass provides useful information and confidence in interpretation. There is also a gas-holdup optical-sensor tool that uses optical-sensing technology for direct detection of gas in producing wells. In gas/liquid mixtures, optical signals reflected by the probes vary from liquid to gas in a binary manner. These data enable determination of gas holdup and gas-bubble count. Gas detection is achieved with an optical sensor having an optical index that is low for liquid and high for gas. Relative bearing and caliper measurements are included to determine exact positions of the probes at any time.

Field Example

The field example is a Middle East Lower Cretaceous carbonate reservoir. The producing intervals are predominantly limestone, with intervening tight dolomite streaks. A gas cap overlies the reservoir, and an aquifer provides weak pressure support. The reservoir is approximately 250 ft thick. The porosity of the producing zones is approximately 30%, and the average permeability is 13 md. The oil has a gravity of 42°API. Because of relatively low permeability and the presence of a large gas cap, field development will use horizontal wells to increase well productivity and drainage area and minimize gas cusping and water coning. Although horizontal wells are placed in the oil column with optimum distance from the gas/oil contact (GOC) and the water/oil contact to avoid early breakthrough of gas or water, early increases in GOR or water are observed in certain wells because of heterogeneities and fractures intersecting the wellbore. Identifying unwanted fluid-entry intervals increases the understanding of reservoir characterization and improves subsequent remedial actions. This case is a high-GOR horizontal well. It produces no water and has a 2,800-ft horizontal length.

Well History. The subject well was drilled and put on production in 1998. This well was completed with a $4\frac{1}{2}$-in. liner and was perforated through almost the entire horizontal section. The wellbore was placed 110 ft below the GOC to optimize production and minimize gas cusping. Initially, the well produced dry oil with gas in solution. However, the GOR gradually increased after 2 years of production. To keep the GOR low, the choke size was varied. This exercise fine-tuned choke size in favor of oil rate. When the well began to produce at a high GOR, it was necessary to find the gas-entry intervals. The well trajectory, openhole-log results, and image logs are shown in **Fig. 2.** The well trajectory goes up at the end. To avoid any gas cusping through this section, the well was not perforated in the toe section.

Well Logging. The integrated production-logging tool string with an optical-sensor tool was run. This configuration allowed real-time determination of both gas and water holdup. Pulsed-neutron three-phase holdup was recorded as an independent measurement to verify and increase the confidence in oil, water, and gas holdups. The trajectory and production history suggested that only low sides of the wellbore would have stagnant water. To obtain flow rates of oil and gas, holdup and velocity data were required. As planned, flowing passes were conducted first, followed by shut-in passes after 4.5 hours of shut-in.

Electrical flow-imaging sensors identified a small amount of stationary water in the deepest low side of the wellbore. In addition to optical and electrical probes, pulsed-neutron borehole sigma and the inelastic far/near ratio provided holdup information in real time. Borehole sigma supported the presence of stationary water.

Although optical- and electrical-probe holdup data are direct and quantitative, borehole sigma and inelastic ratio can be used on the basis of individual phase values. Because the probe locations are known, flow-image output yields the flow distribution along the wellbore. Both in-line (smaller) and full-bore spinners were included in the tool string. Because the flow regime often is segregated in horizontal wells, the spinner can be used only when it is completely immersed in one phase. After obtaining quantitative holdup data, wellbore- and spinner-size data are used to determine whether the spinner is immersed in one or two phases. For example, a minimum 70% of holdup for a less dense fluid would allow a smaller in-line spinner to be completely immersed in a lighter phase in a 4-in.-inside-diameter completion. Therefore, if the holdup for the heavier phase is more than 30%, the spinner would be immersed in two phases. In that case, the spinner velocity corresponds to neither phase, assuming flow is segregated. An 88% holdup is required for the fullbore spinner to be immersed totally in the lighter phase.

In high-GOR wells, temperature data can be useful to increase confidence for identifying gas-entry intervals, especially for the first entry and for significant gas entry from one interval. The temperature-drop data supported the entry-interval determinations.

Results

After running the first flowing pass, it was determined that gas occupied approximately 80% (holdup) of the wellbore in the first 700 ft of the horizontal section. Then, gradually, gas holdup decreased and correlated with the deviation. Gas holdup increased as well deviation became greater than 90°. During shut-in, the fluids segregated as expected. The holdup distribution was obtained from the endpoints of the inelastic ratio. Borehole sigma also correlated well with the presence of gas and oil. As expected, gas was trapped in the high sides of the wellbore.

Spinner data can be used to determine the velocity of gas if the gas holdup is 70%

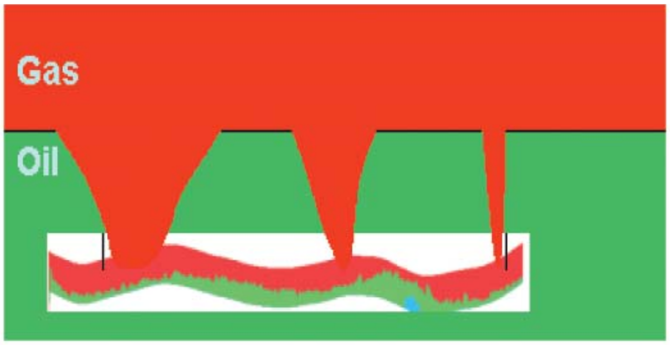

Fig. 3—Study results showing gas cusping from higher-permeability layers.

or greater. Therefore, the gas-flow profile indicated that major gas entry (approximately 80% of the total gas entry) occurred along the high side of the well, close to the heel. Openhole and image logs suggest that this interval is a different rock type, which was confirmed by log-derived permeability. A second entry was identified from the second high side of the well, where the well goes up again and crosses into the high-permeability rock. Minor gas entry also was detected from the toe section. Although different facies were observed in image logs, the quantitative effect on the flow profile could not be predicted. The results of the integrated production logs provide more-confident reservoir-characterization information. Gas entry from higher-permeability rocks indicated that gas was cusping down from these intervals, as shown in **Fig. 3.**

Generally, very small temperature variations are expected and seen in horizontal wells. However, in this well, the first entry and subsequent significant gas entries caused differentiable temperature cooling, supporting the findings. It should be noted that oil-holdup distribution did not allow determination of the oil velocity with the spinner. Hence, the oil velocity could be obtained only with a phase-velocity log.

Conclusions

The integration of diagnostic flow profiles, gas-entry intervals, and well evaluation can yield important information about reservoir characterization and dynamics. This case history revealed that the effect of the gas breakthrough could not be predicted confidently on the basis of static data alone. The identification of entry intervals and the relation to certain facies can be helpful for future well-placement practices.

Numerical simulations supported the entry intervals. Shut-off considerations on the high side of the wellbore sections suggested that GOR could be minimized. However, no significant increase in oil production could be obtained. As an alternative, a sidetrack-well option was considered. Production predictions yielded increased oil production with no free-gas. JPT