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Improving Horizontal Completions in Heterogeneous Tight Shales

Production from nanodarcy-range-permeability shale formations requires extensive hydraulic fracturing, large volumes of water, and closely spaced wells. Comparing calculations of the possible fracture-surface area created during treatments to production results indicates that a large portion of that surface area is ineffective for production, resulting in ineffective use of resources. A fundamental understanding is required to improve the efficiency of horizontal completions in producing shales. The objective of this study was to improve completion design and horizontal-well-completion efficiency.

Introduction

When considering tight-shale-formation characterization and completion design, one should evaluate the formation characteristics conducive to economic production: reservoir quality (RQ), representing the multiple properties defining reservoir potential, and completion quality (CQ), representing the multiple properties defining the potential for creating and sustaining a large surface area in contact with the reservoir. RQ and CQ properties vary in the near-wellbore and far-wellbore regions. For CQ, the far-wellbore region represents the region of contact between the created fracture and the reservoir. Well production depends on this surface area being in contact with good RQ, and depends on conditions of containment, fracturability, rock/fluid interactions, and loss of surface area and fracture conductivity during production. The near-wellbore region represents the choking point between the created surface area and the wellbore. The goal is to maximize connectivity between the fracture system and the wellbore. This goal is attainable by minimizing near-fracture tortuosity, maximizing fracture width, reducing breakdown pressures, and limiting the risk of solids production. The result is a nonsubjective and consistent method that provides a means for understanding variability in fracture performance along wellbores (e.g., inferred from microseismic monitoring, trace analysis, and stage-by-stage flow measurements) and for selecting perforation stages on the basis of measured or log-inferred rock properties. The method also provides a means for monitoring consistency between the predicted values and measured results.

Surface-Area Requirements

Numerical simulations with single-phase gas production through a fracture were conducted as a function of reservoir-fluid properties to provide information on the surface-area requirements for attaining a desired production rate. Sensitivity analysis of input variables indicated that reservoir pressure, reservoir permeability, and fracture-surface area are the dominant input properties. By fixing reservoir pressure to the normal reservoir pressure to the normal production. For wellbores with six producing stages, the required surface area per stage is 1 × 10^6 ft² for 5 MMcf/D and 2.8 × 10^6 ft² for 1 MMcf/D. This corresponds to an equivalent fracture half-length of 2500 and 708 ft, respectively, for a 200-ft-thick reservoir.

In the comparison, the authors used 483,000 gal of slickwater and 390,900 lbm of sand, and, by assuming an average fracture width of 0.15 in., they calculated a created fracture-surface area of 10.7 × 10^6 ft²/stage and 64.3 × 10^6 ft² for 6 stages. Comparison with Fig. 1 indicates that significantly more fracture-surface area is created than required for economic production, and the ratio of these areas varies from 10:1 to 38:1. It is reasonable to assume that a significant portion of the created surface area extends outside the reservoir thickness as a result of lack of containment, and because of the heterogeneous distribution of RQ. If the fracture is complex, the fracture branches will support smaller fracture widths and some branches may become inaccessible to the proppant and be disconnected from the rest of the fractured system. It is possible that some level of inhibition may take place, thus reducing the liquid volume available for creating surface area. First-principle calculations suggest that inhibition may be limited to 1–3% of the total volume pumped. Therefore, a considerable portion of the created surface area is ineffective and does not contribute to pro-

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For a limited time, the complete paper is free to SPE members at www.jptonline.org.

duction. Also, microseismic monitoring during fracturing provides a measure of the total created surface area, not a measure of the effective surface area. The calculations also show the importance of improving the efficiency of the hydraulic-fracturing process.

**Heterogeneity**

Vertical and lateral heterogeneity in tight-shale formations (organic-rich mudstones) results from post-depositional, diagenetic transformations within the stratigraphic column. Vertical heterogeneity is evident from log interpretations and from core measurements. The lateral heterogeneity is more difficult to visualize and becomes apparent only after multiwell analysis and integration of this with seismic data. A direct consequence of the strong diagenetic transformations is the significant variability in material properties (e.g., observed as differences in log responses, differences in gas compositions from mud-log analysis, and different properties measured on cuttings along the length of the well). This is the case even when horizontal wells are steered. Wellbore steering helps reduce the bigger contrast in properties between lithological units and limits the variability to diagenetic alterations within these units. The latter, however, are still significant in most tight-shale plays.

**CQ and RQ**

This method suggests that well productivity is the product of RQ and CQ. RQ is defined by such properties as hydrocarbon-filled porosity, permeability, pore pressure, organic content, and organic maturation, which together describe the reservoir potential. CQ is defined by such properties as containment of fracture-height growth, fracturability, low rock/fluid sensitivity, and low propensity to solids production, which together describe the ability for creating a large-surface-area fracture in contact with the reservoir. Maintaining surface area in contact with the reservoir, while preserving fracture conductivity during long-term production, is the challenge. Fracturability describes the amount of surface area created per unit of reservoir volume (i.e., fracture complexity by branching). It is desirable for this property to be reasonably high. However, too much complexity results in high net pressures (because of stress-shadowing interactions) and in limitations of proppant transport (because of tortuosity and changes in fracture width). Unfortunately, poor proppant transport is the source of loss of surface area and loss of fracture conductivity during production.

Rock/fluid sensitivity describes potential problems associated with water imbibition (large reduction in relative permeability to gas); reduction in surface hardness (increased risk of proppant embedment and associated loss of surface area and loss of fracture conductivity); and salt dissolution, mixing, and possible precipitation along the propped section of the fracture. Because of the large surface area exposed to the fracturing fluid, even minor conditions of rock/fluid sensitivity may result in severe reduction in overall production. Also, the propensity of solids production is controlled predominantly by reservoir pressure, rock permeability, and the tensile strength of the rock. Solids production results from a tensile failure (spalling) at the fracture face, resulting from excessive drawdown pressures, which is otherwise desirable to accelerate the production of fracturing water and promote higher initial production. The problem is most frequent in overpressured reservoirs and increases as the permeability and tensile strength of the reservoir decrease.

**Near- and Far-Wellbore Conditions**

RQ and CQ properties may be different in the region near the wellbore and away from the wellbore. The far-wellbore region represents the region of contact between the created hydraulic fracture and the reservoir. Well production depends on this surface-area contact with good RQ and depends on conditions of containment, fracturability, rock/fluid interactions, and prevention of loss of surface area and loss of fracture conductivity during production. The near-wellbore region represents the choking point between the created surface area and the wellbore. Here the goal is to maximize connectivity between the fracture system and the wellbore by minimizing near-fracture tortuosity, maximizing fracture width, reducing breakdown pressures, and limiting the risk of solids production. This goal is achievable by evaluating the variability of rock properties along the horizontal wellbore and selecting rock types with properties most amenable to satisfying the goals. See the complete paper for details of the evaluation process.

**Applications**

Near-Wellbore CQ for Various Rock Facies. Results from evaluating near-
identify and classify rock units on the consistency of the log responses to classes by log fingerprinting. It relies on obtaining the identity of the rock (HRA) of logs. This method is analogous by use of heterogeneous-rock analysis identified systematically and nonsubjectively. These subtle changes can be identified in material properties. Results from core analysis and multi-well log analysis support this observation. These subtle changes can be identified systematically and nonsubjectively by use of heterogeneous-rock analysis (HRA) of logs. This method is analogous to obtaining the identity of the rock classes by log fingerprinting. It relies on the consistency of the log responses to identify and classify rock units on the basis of their distinct bulk-log responses. Consistency and nonsubjectivity in identifying dominant rock facies responsible for the vertical and lateral heterogeneity are fundamental prerequisites for understanding heterogeneous formations. Sampling selection, testing, and the development of log-based (or seismic-based) models for reservoir characterization depend strongly on the validity of this process.

Fig. 2—Example of HRAs of logs for identifying lateral variability in rock facies along the length of a horizontal wellbore. The analysis is supplemented by comparison with known facies that were identified previously in a nearby vertical well with core.

wellbore CQ for the rock facies indicate that organic/argillaceous mudstone exhibits the highest near-wellbore fracture width, the lowest breakdown pressure, the lowest far-field minimum horizontal stress, and a reasonably low propensity for solids production (i.e., high critical flowing-well pressure). It is a good candidate for perforating and fracturing. In contrast, argillaceous shale exhibits the lowest near-wellbore fracture width, the highest breakdown pressure, the highest far-field minimum horizontal stress, and a high propensity for solids production. It is a bad candidate for perforating and fracturing.

Identifying Rock Types Along Horizontal Wellbores. Advecive flow and shear displacement of colloidal sediments during deposition and post-depositional diageneric transformations, including the interaction of living organisms and decaying organic matter, are the principal source of lateral heterogeneity in tight shales. These processes result in subtle changes in texture and composition that result in measurable changes in material properties. Results from core analysis and multi-well log analysis support this observation. These subtle changes can be identified systematically and nonsubjectively by use of heterogeneous-rock analysis (HRA) of logs. This method is analogous to obtaining the identity of the rock classes by log fingerprinting. It relies on the consistency of the log responses to identify and classify rock units on the basis of their distinct bulk-log responses. Consistency and nonsubjectivity in identifying dominant rock facies responsible for the vertical and lateral heterogeneity are fundamental prerequisites for understanding heterogeneous formations. Sampling selection, testing, and the development of log-based (or seismic-based) models for reservoir characterization depend strongly on the validity of this process.

Fig. 2 shows an example of HRA results along a vertical pilot well and the subsequent lateral well. The analysis was conducted from density and spectral gamma logs. Results identified two dominant rock facies, with thin appearances of a third facies, along the length of the horizontal wellbore. This information is fundamental for perforation-stage design and near-wellbore CQ assessment.

Near-Wellbore CQ. Fig. 3 shows the near-wellbore-CQ analyses along a horizontal wellbore of a known tight-shale play. Rock classes were identified with HRA of well logs. Four rock classes were defined (green, light blue, red, and black). These represent diageneric facies in the play. The RQ index (RQI) is evaluated on the basis of the combined assessment of gas-filled porosity (GFP), gas permeability (k), and total organic content (TOC). In the RQI channel, brown and red colors signify regions with best RQ. The near-wellbore-CQ index (CQI) is evaluated on the basis of the combined characteristics of near-wellbore fracture width (FW), breakdown pressure (BP), and solids-production potential (SPP). In the CQI channel, brown and red colors signify regions with best near-wellbore CQ. It is desired to perforate along the rock class with the best RQ and best near-wellbore CQ. The analysis showed that the black rock class (calcareous mudstone) was the best choice for perforating. Conversely, the analysis showed that the red rock class (argillaceous mudstone) would not be recommended for perforating.

Conclusions

Tight shales are strongly anisotropic and cannot be approximated by use of isotropic models. These will lead to inappropriate conclusions and production strategies.

Stress concentrations at the wellbore face in anisotropic rocks depend on rock elastic properties. Thus, they are different rock types with different stress concentrations, breakdown pressures, and fracture widths.

The fracture-width evaluation assumes the generation of a single near-wellbore fracture, which may not always be the case. However, it provides a basis of comparison for the fracture-width development as a function of the rock type.

The far-field horizontal stress depends on the anisotropic elastic rock properties, which change from rock type to rock type. Thus, one needs to understand the combined effect of the anisotropic rock properties on the far-field stress and on the near-wellbore-stress concentrations on a rock-class by rock-class basis to estimate the breakdown pressures and near-wellbore fracture widths.

HRA of logs is used to identify rock classes uniquely and nonsubjectively along the length of the horizontal wellbore. Because all the measured logs are included in the analysis, this provides higher sensitivity and more-consistent identification of rock classes, compared with the use of fewer logs.

The analysis is based on fracture-width, breakdown-pressure, and solids-production predictions that
are derived from physical properties and on the basis of physical principles regarding the consequences of these properties on hydraulic fracturing. Therefore, it is easy to understand and implement.

Combined assessment of these conditions enables selecting the best rock types for perforation and anticipating problems on others. JPT

Fig. 3—Near-wellbore-CQ analyses along a horizontal wellbore. Rock classes are identified by HRA of well logs.