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Diagnostics Reveal Stimulation Effects

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DENVER–Effectively applying multiple fracture mapping diagnostics technologies can help accelerate the learning curve in horizontal resource plays, guide well completion optimization strategies, and give the operator exceptional knowledge concerning which technologies to choose when targeting specific issues in future field development work.

The capabilities of multiple diagnostic technologies were demonstrated in a project involving a "wine rack" of wells completed in Niobrara A, B and C benches on the Horsetail 30F well pad in the Denver-Julesburg Basin. An extensive survey was performed using both near-wellbore and far-field diagnostics to give the operator insights into the completions order of the wells, height growth in various benches, well spacing, lateral landing points, the effects of varying treatment types and sizes, and cross-well communication.

This project began with the intention to expand the limits of an eight-well test project on the Horsetail 30F pad to determine optimum well spacing while applying diagnostic tools to evaluate performance. A technical steering team and an overseeing senior management advisory committee were formed to manage project expectations. The goal was to evaluate the number of laterals per section to contact as much of the reservoir as possible to help maximize reserve recovery and production per unit.

To address such a high-level goal, crucial direct learning objectives from this project included:

- Optimum well density/well spacing in the Niobrara A, B and C benches;
- Optimum fracture spacing;
- Number of stages per lateral;
- Treatment size and design;
- Completions timing/order; and
- Wellbore placement.

Diagnostics Technologies

The near-wellbore diagnostics included permanently installed fiber optical distributed temperature sensing (DTS) and distributed acoustic sensing (DAS), wellbore pressure gauges, and a full suite of water, oil and proppant radioactive tracers to measure stimulation effectiveness, interstage communication and cross-well communication.

The far-field diagnostics solutions included a new hybrid borehole microseismic/tilt array tool string deployed in a dedicated vertical observation well to measure fracture network height resulting from direct fluid placement measured near select stages. Surface-deployed interferometric synthetic aperture radar tilt tools were used to measure microdeformation before, during and after stimulation to quantify the proportion of fluid placed along respective primary and secondary azimuths, fracture dip, and the vertical versus horizontal component to measure the relative degree of complexity.

The analysis was performed on individual diagnostics independently, and subsequently combined interpretations led to a better understanding of the subsurface. In addition, surface microdeformation data provided significant insight into the effects of "zipper fracturing" and the importance of the treatment order of

FIGURE 1

Well Layout, Target Bench and Order of Treatment for Horsetail 30F Pad

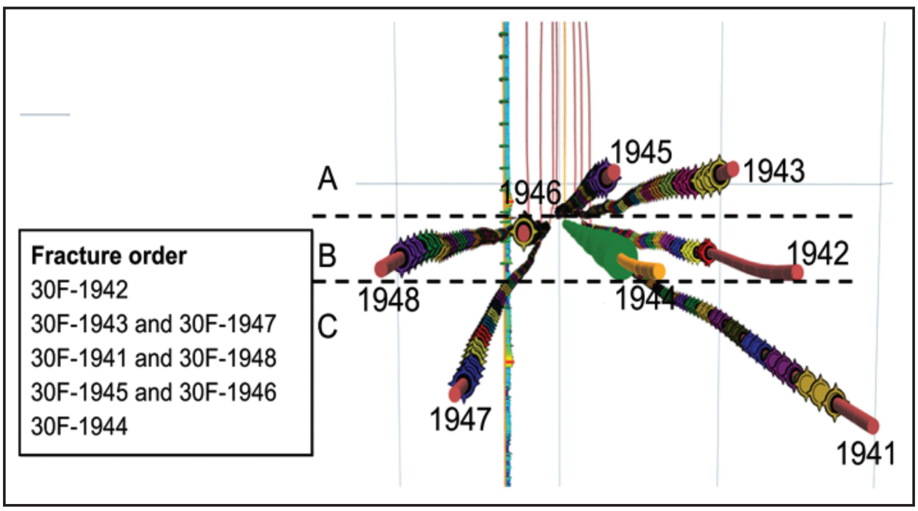


FIGURE 2A

Real-Time DTS Information Showing Fluid Distribution in Three Clusters

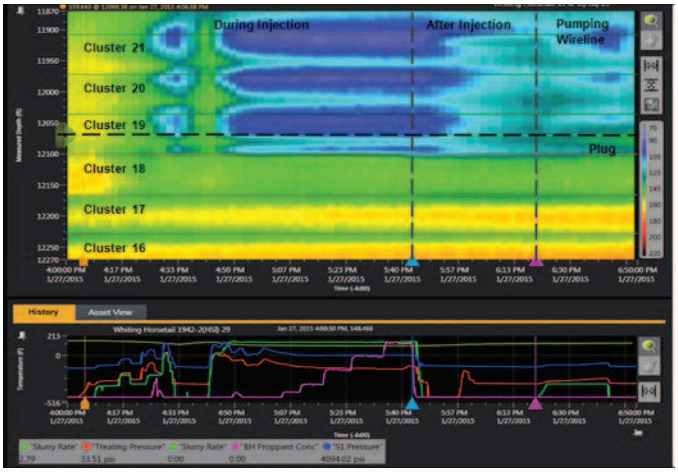
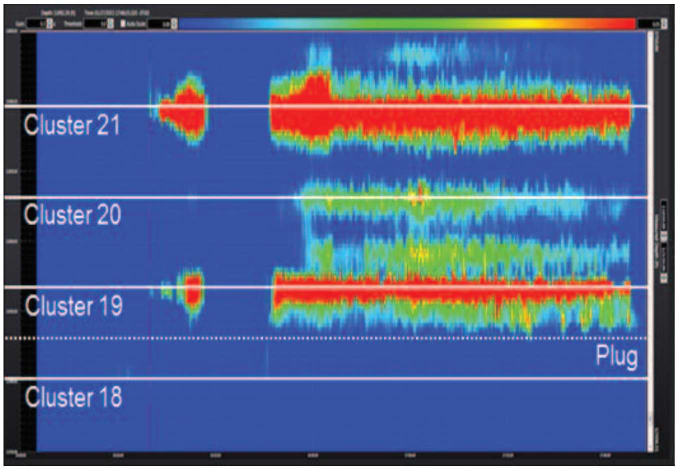


FIGURE 2B

Real-Time DAS Information Showing Acoustic Intensity in Same Clusters



the wells in optimizing results.

With all data available, a fracture model history match on the permanent fiber optics well was constrained to the measured diagnostics. The final match between the aerial deformation from the surface tilt and calibrated fracture model was excellent.

Understanding the actual hydraulic fracture geometry is important in any unconventional field development because it dictates the stimulated reservoir volume and drainage patterns. While understanding the effects of various parameters (treatment type, fluid type, stage lengths, number of perforation clusters, etc.) on fracture geometry is essential, it is also important to understand the effect of multiple wellbores on a well pad.

The treatment order of the eight Horsetail 30F wells was decided with the objective of maximizing learnings. As shown in Figure 1, the 1942 well was treated first. Wells 1943 and 1947 were then zipper fractured to measure the effect of interference on the farthest wells and between the Niobrara A and C benches. Wells 1941 and 1948 were then zipper fractured to measure interference between the B and C benches. Well 1944 had the microseismic monitoring downhole array and was treated last.

Permanent Fiber Optics

Permanent fiber optics were installed on the outside of the casing string in Well 1942 (B bench) and cemented in place. This permanent fiber provides monitoring for the life of the well, with DTS and DAS simultaneously recorded along the entire wellbore over time. This provides the ability to monitor the heat of hydration post-cementing to understand the top of cement, acquire real-time information on primary treatment and quantitative fluid distribution along the entire lateral section, assess cross-well interference during offset well treatment, and monitor production for the life of the well.

Well 1942 was completed in 37 stages using the plug-and-perf methodology. Stages one-16 were treated with cross-linked fluid, and stages 17-37 were treated with a slickwater system.

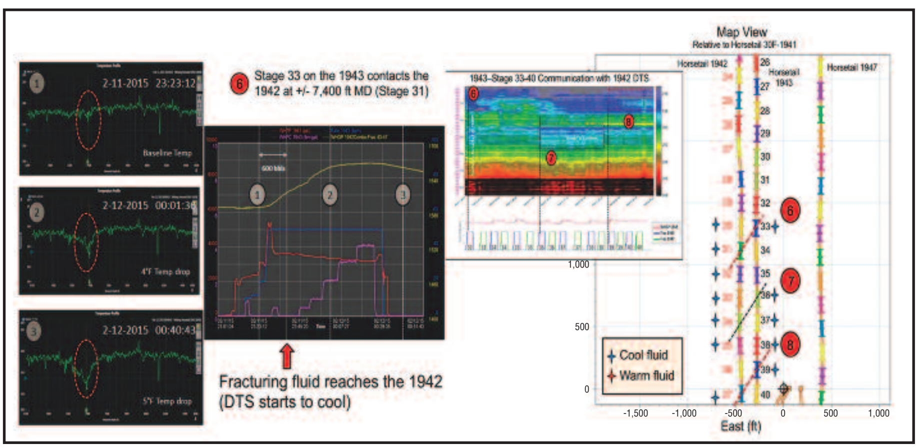
Figures 2A and 2B show examples of the real-time DTS and DAS data during a stage for clusters 19, 20 and 21. The DTS information shows fairly good distribution of fluid among the three clusters on a qualitative analysis in this stage. Higher acoustic intensity is observed in the DAS data at the toe- and heel-ward clusters and relatively lower at the middle cluster.

The DTS and DAS information was then input through a thermo-hydraulic module to obtain quantified fluid distribution across the entire lateral. This information allowed the operator to compare the performance of the two different fluid systems used to complete the stages. The fiber optic cable terminates near the depth of stage 4, so data exists from stages five-37. Stages 17-21 also employed a near-wellbore diverter material as an experiment to evaluate the effect of diverters with fiber optics.

Looking at the quantitative distribution of fluid per cluster in the 1942 well, 47 percent of all clusters were within a 20 percent variance of the designed volume (calculated by assuming equal distribution of the stage volume within the clusters of that stage). Thirty percent of the clusters took less than the designed volume and

FIGURE 3

Example of Cross-Well Interference Analysis using Fiber Optics



23 percent took more. No significant variations were observed with the fluid design (slickwater versus cross-linked fluid) on distribution within clusters. It is also worth noting that 48 percent of time, the heel cluster took the most fluid during the stages.

The DTS data from the stages were then divided into initial fluid distribution before dropping the diverter agent, and the post-diverter flow allocation to understand the impacts directly related to diversion. Quantitative profiling is necessary because qualitative temperatures can be misleading as a result of near-wellbore cooling and warming, when rates might be lowered to drop the diverters. At the time of completion of the project, DTS was being used to quantify volumetric contributions. Since then, rapid advancements have taken place in DAS, and currently DAS is used as the primary quantified diagnostics for fluid and proppant.

Figure 3 shows an example of cross-well interference analysis using fiber optics. The three traces at left show the shape change in the temperature trace on Well 1942 during a stage on Well 1943. The referenced timelines are shown on the treatment chart. The DTS plot shows the same events and a cold streak on Well 1942. These observations, when plotted along Well 1942 with a starting point on Well 1943 (fracturing stage depth), show an azimuth to fluid travel.

In addition to insights gained from multiple production profiles performed later in the life of the well, the information from fiber optics helped the operator understand:

- The effect of varying parameters on completions;
- The effect of using diverters with quantified pre- and post-diverter fluid distributions;
- Cross-well interference during treatment to optimize well spacing; and
- The quantitative distribution and number of near-wellbore fractures along the lateral.

Microdeformation Mapping

An array of tiltmeters was coupled with geophones in a nearby vertical well to analyze downhole microdeformation. In addition to measuring fracture height, the downhole tiltmeter data also were used to improve the interpretation of microseismic data for the project. Microseismic height interpretations for stages outside of the viewing distance of the hybrid array could be calibrated by the hybrid array stages.

Tiltmeters also were deployed in shallow (35-40 feet deep) holes dug on surface in an array over the treatment pad. This array consisted of 64 surface tiltmeters installed in an obround pattern over the pad, covering an area of approximately 7.5 square miles. The array measures deviation of the earth above each induced fracture stage. This deviation pattern is related to the induced fracture geometry occurring beneath it during a discreet period of time and then resolved to the primary azimuth of the fracture and the stimulated reservoir area by performing stimulated reservoir characterization analysis.

Figure 4 shows the fracture azimuths for each stage of Well 1943, which was zipper-fractured along with Well 1947. Fracture length is arbitrary in this image, but these results demonstrate the change in primary fracture azimuth along the lateral from the toe to the heel resulting from stress orientations and fracture order in this zipper frac treatment. On the west side, Well 1942 (not shown in Figure 4) was fractured before performing the 1943 and 1947 well zipper fracs. The observation of the greater longitudinal fractures mostly near the heel of this well was a result of the alteration in the downhole stress field.

Surface and downhole microdeformation results measured the direct deformation caused by hydraulic fluid placement and the relationship between well proximity and changes in the stress field.

Microseismic mapping of the treated wells was performed using the two downhole arrays. The array deployed laterally in Well 1944 was repositioned to maintain proximity to each treatment stage. The second array was deployed vertically along with the downhole microdeformation

FIGURE 4

Azimuthal Results from Surface Microdeformation (Well 1943)

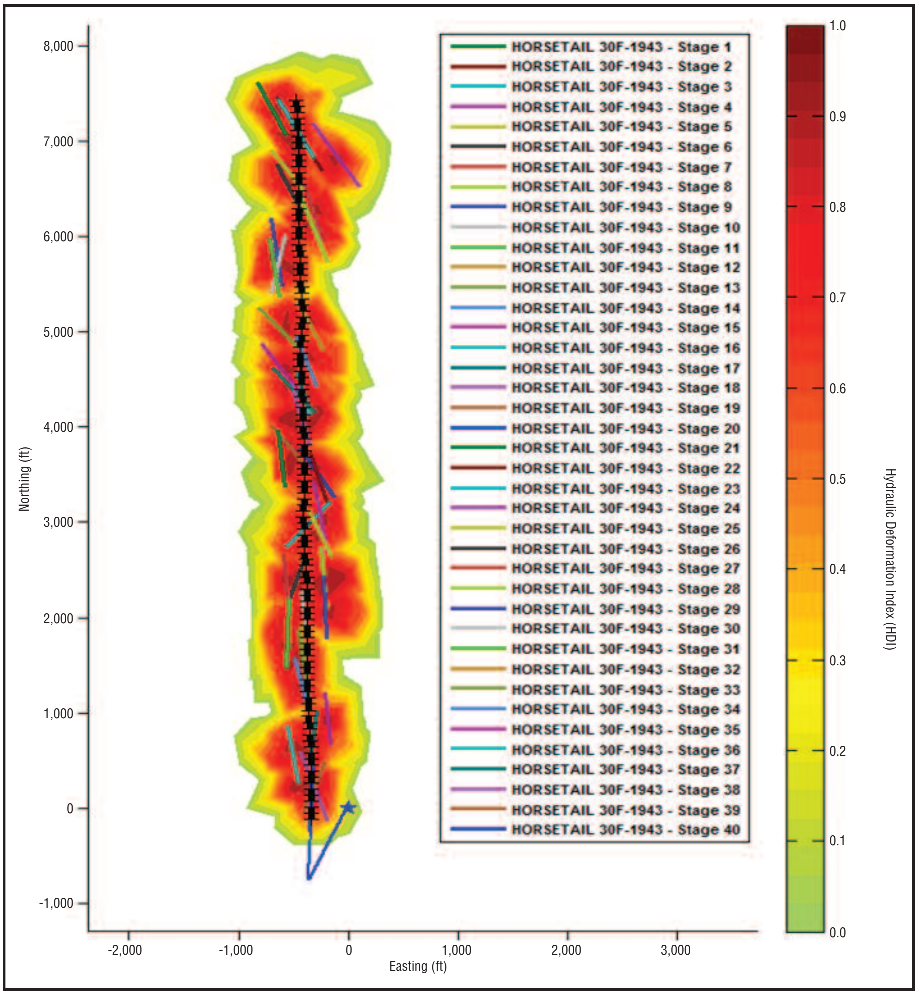
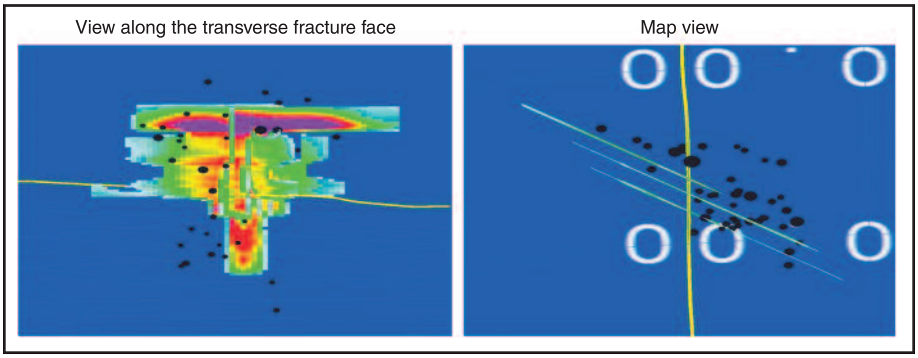


FIGURE 5

3-D Fracture Geometry Output from Calibrated Model



tiltmeters in the hybrid array. This provided co-location of events and greater height accuracy in event locations for the project overall. The microseismic mapping results provided additional measurements for stage azimuth, stage isolation and fracture network growth with time.

Fracture Modeling

To build a calibrated fracture model, direct measurements are required to constrain it. This project comprised a diverse arrangement of diagnostic and sensor information, which provided the opportunity to constrain a fracture model along several different parameters and determine whether the model could match what was able to be measured.

Vertical offset well logs were used to build the reservoir for the 3-D fracture model. Log data available for the project included standard gamma, porosity and resistivity, which typically are obtained from triple-combo logs. Additionally, spectral gamma, dipole sonic and magnetic resonance logs were used to create a more complete reservoir model.

Along with the post-job pressure history, bottom-hole gauge, microseismic and DTS data, diagnostic fracture injection test (DFIT) and step-rate tests were performed for analysis to incorporate into the fracture model.

The DFIT was useful for confirming the minimum stress calculation (closure stress) from the log-derived rock properties, as well as obtaining an accurate value for pore pressure, process zone stress, critical fissure opening pressure, and pressure-dependent leakoff. All of these parameters influence fracture growth and only can be measured from the pressure decline analysis of an injection test. The DFIT also was able to provide an upper limit on reservoir permeability.

The objective was to perform a post-job pressure history match for each stage that not only would honor the information from the microseismic data, but also incorporate the volumetric information from the DTS analysis. Typically, it is possible that a net pressure history match can result in multiple fracture geometries satisfying the match. In such a case, the model needs to be constrained by additional physical measurements.

The 3-D fracture model used for post-job pressure history matching is able to adjust the perforation information and match the volume of fluid that passes. This capability was used to perform adjustments throughout the treatments, and it was possible for the model to match each perforation cluster's volume to within 1 percent of the measured value.

The stress-shadowing ability of the 3-D fracture model generated an asymmetry in each stage's fracture dimensions. These fracture dimensions then were compared to the asymmetry observed from the surface microdeformation analysis. This additional step provided validation for the model or identified the need for additional refinements.

Some of the stages contained both surface pressure and bottom-hole pressure with downhole pressure gauges. It was possible to obtain a good general pressure trend match during the treatment and also good instantaneous shut-in pressure and leakoff pressure matches in both the surface pressure and downhole pressure.

The microseismic events measured during the treatment were used to adjust the generated fracture heights and lengths, in general. Heights also were calibrated by the microdeformation results. Ensuring the modeled fracture dimensions are constrained by the measured data and a pressure history match establishes a calibrated model.

Figure 5 shows the 3-D fracture geometry output from the calibrated model showing the relationship to microseismic data, while Figure 6 shows an overlay of the predicted fracture asymmetry to measured asymmetry from surface microdeformation.

Performing this calibrated and constrained fracture modeling provided high confidence in the obtained fracture geometry given the excellent match with measured microdeformation data. These constrained models helped decision making on a well-pad level and combined all diagnostics information to allow design changes.

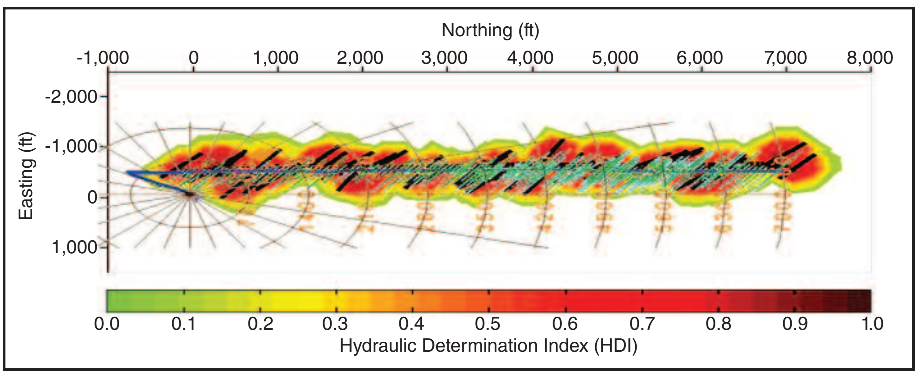
Key Takeaways

Key takeaways from the stimulation phase of the project include:

- The operator learned the optimal well completions order to enhance recovery and minimize the longitudinal effect observed resulting from stress interactions. This was applied to subsequent completions in the field.

FIGURE 6

Hydraulic Determination Index (Predicted and Measured Fracture Asymmetry)



• The operator was able to compare interwell interference information with production interference testing performed during a later phase of the project. This led to improved well spacing.

• Constraining the fracture models and obtaining an excellent match to measured microdeformation data provided confidence in the approach. This information can be used to generate constrained and calibrated fracture models for the entire well pad and help make key decisions concerning well spacing, completions size, number of stages and completion order.

• Many factors comprise such projects. The key to delivering a successful project with value added to allow fiscally vital decisions concerning well pads or asset levels (based on measured data) is the ability to manage multiple data sets and have analysis capabilities in multiple domains. This needs to be achieved to deliver value from the design or experimental project in an efficient and effective manner.

A variety of diagnostic tools were successfully deployed, integrated and used to improve the understanding of multiwell stimulations on the Horsetail 30F pad. The project's success has depended largely on collaboration between the operator and service company in determining project objectives, identifying the correct diagnostic applications to achieve those objectives, and establishing the operational plan to execute the project.

Significant advancements have been made in individual diagnostics and combined interpretation capabilities since this project was planned and executed, and only a portion of the conclusions and results from the project are presented in this article. The combined data provide insight into a number of project objectives, including understanding near-wellbore fluid distribution, interwell communication, fracture asymmetry, and induced fracture geometry in length and height. Significant understanding about the order of operations for well completion was developed and the optimal completion order determined.

The fracture geometry and stage volumetric ultimately constrained the fracture models, resulting in excellent pressure matches and matched measured asymmetry from surface deformation. Ultimately, the confidence provided by these models allows for higher confidence in future well planning. ❒

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