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High Accuracy Leak Detection Performed on Entire Live Wellbore in Real Time Using Fiber-Optic Diagnostic-Capable Coiled Tubing

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Abstract

Using fiber-optic coiled tubing (CT) to perform distributive temperature sensing (DTS) and distributed acoustic sensing (DAS) logging to identify multiple points of leak detection is discussed using a case study. The case study provides an in-depth review of the operation performed on a land-based horizontal well where a single well intervention run successfully logged the entire wellbore, resulting in the identification of multiple depths where casing had failed during an initial hydraulic fracture stimulation attempt. Additionally, a brief review of fiber-optic logging techniques and equipment is described.

Introduction

Operators in an unconventional oil shale development face a series of unique challenges not present in conventional field development. The rapid development of unconventional reservoirs and the significant amount of wells necessary to access trapped reserves compounds the problem when aligned with the requirement for well integrity to withstand the strain of hydraulic fracturing. This invariably causes a potentially increased risk in the occurrence and financial consequences of casing integrity issues. Hydraulic fracturing uses high-pressure, high-rate fluid to deliver effective stimulation placement to formation. A well integrity failure occurrence, such as a casing leak, during hydraulic fracturing activities causes ineffective stimulation placement and greater casing integrity issues as well as jeopardizes the entire stimulation and future production of a well.

Many conventional methods of leak detection are currently used by the international oil and gas industry, including (but not limited to) using retrievable packer isolation and pressure testing, running a production log, and/or acoustic "noise" log. These methods require operations limited by timely intervention and single-point identification and/or have difficult operational application in complex and horizontal wellbore geometries. In the case of multiple casing leaks within the horizontal section of a modern shale oil wellbore completion, the potential risk of leaks being inaccurately identified or missed during the intervention exists. Fiber optic-capable CT can be used to perform a single-run well intervention and confirm or identify sections of failed well integrity for the entire wellbore with a high degree of accuracy.

Overview of Fiber-Optic Technologies

Fiber-optic CT consists of a single e-line and fiber-optic cable set with multiple fiber-optic lines installed on the inside of a CT work string. The fiber-optic cable begins at the reel of the CT unit at a data acquisition box and extends throughout the length of the CT work string where it terminates at the bottomhole assembly (BHA) just below the CT connector. CT-deployed fiber optics can be run for multiple trips and/or in multiple wellbores, enabling the capability to obtain DTS and DAS data in nonpermanently instrumented wellbores with lower operational complexity (Natareno et al. 2019).

The CT is run in and out of hole on an otherwise standard CT unit to act as the conveyance mechanism for the fiber-optic cable. During this conveyance, standard CT operations can be executed while the fiber-optic cable remains protected within the CT. Once the fiber optics are positioned within the well at the desired depth, the interrogator laser is sent through the fiber-optic connection at surface and throughout the fiber optics within the well. The backscatter of light is then recorded by onsite equipment for data interpretation and processing. The backscatter data can identify temperature variation throughout the wellbore in real time and is referred to as DTS. Additionally, backscatter light can be interpreted to identify acoustic events in the entirety of the wellbore in real time and is referred to as DAS.

This data is gathered and processed to identify areas of variance or irregularity that can then be used to assess localized wellbore, reservoir, and CT conditions. Data acquired during acoustic and temperature logging processes in its raw form are not conclusively interpretable. Through the use of complex filter algorithms, fiber-optic data can be "cleaned" to indicate conclusive depths of anomaly; essentially, identifying points of interest, increased activity, or anomalies throughout the wellbore. Based on the scope of the work being performed, this can vary greatly. For temperature logs, this can identify a variation in temperature over a small or large section that can be compared to the expected temperature of the section and then used to identify anomalies. For acoustic data, the "noise" of a well is filtered to identify areas of increased acoustic activity that represent the flow of fluid at an increased rate or at an increased presence in gas. Data can then be used to draw conclusions on the downhole activity based on wellbore conditions and history.

Case Study

Operational Summary

An operator had a horizontally drilled but uncompleted well that had not been fully stimulated in the Middle Bakken Formation. The well had a final total measured depth (TMD) of 21,268 ft comprised of a 7-in. vertical and 4.5-in. 10,607-ft horizontal liner with heel-to-toe build between 88 and 93° deviation. The well had three stages of stimulations completed in the toe of the well when a potential leak was identified near 14,223 ft at a 90° inclination. The operator determined that a casing leak at this depth would jeopardize the remaining stages to be perforated and hydraulically fractured between the previously completed stages and the potential leak. At this time, a retrievable cast-iron bridge plug (CIBP) was set at 20,865 ft using CT to isolate the three stages already stimulated; Fig. 1 shows the wellbore. There was concern around the initial well construction, resulting in the potential for more than one casing failure within the well. The operator had identified an issue with collar leaks in nearby completions of the same field and assumed the problem could be present within the well.

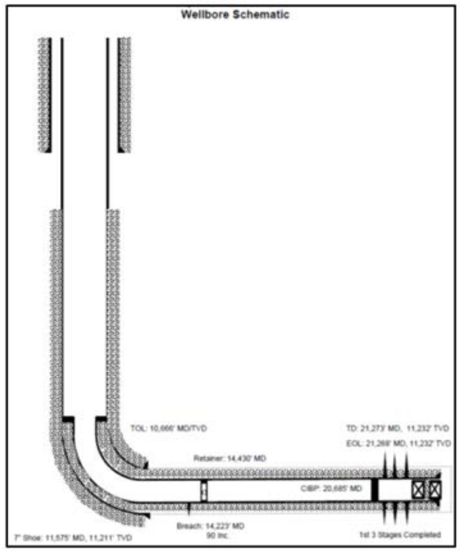

Figure 1—Simplified wellbore schematic.

Operational Concerns

The operator chose to use CT for leak detection because of the inability of wireline to reliably enter the complex wellbore geometry and the prohibitive cost and operational concerns with using a conventional or hydraulic workover unit. Using a settable packer and pressure-test sequence was initially considered. For this method, a settable packer would be set at multiple depths, and then a pressure test would start to monitor for leakoff. After a pressure test passed or failed, the packer would be moved to a new depth, and a new pressure would increase the depth accuracy of an expected leak or continue to verify casing integrity for lengths of undamaged wellbore.

When performed on CT, this operation was limited by the depth that could be reached. For horizontal applications, using an agitator is necessary to combat friction and drag forces that limit achievable depths. The settable packer considered could not be run in conjunction with an agitator. The uncertainty, increased anticipated operational time, and potential to not reach the goal depth of inspection made this option less favorable for the operator. The potential for multiple leakoff points and unknown rates of loss removed the ability to use an acoustic noise tool or production log in place of the packer. Memory production logs require a lower limit of flow not guaranteed to be achieved during injection or production.

CT-conveyed fiber-optic DTS and DAS were chosen because of the high degree of accuracy and operational ease. The fiber-optic coil could be run in hole (RIH) with a BHA using an agitator to help ensure the TMD goal could be reached. The DTS log could then be performed to identify temperature anomalies within the wellbore, and then on the same run, the CT could remain in hole while production and injection tests were performed. During these increased rate and pressure events, DAS data could be used to confirm or challenge the DTS data previously collected, thus achieving the operator's primary goal of leak detection and casing integrity verification throughout the horizontal section of the wellbore in a single run.

Operation Summary

U.S. Land: Middle Bakken Formation.

- CT unit with large capacity tubing reel
- Number of wells: 1
- Number of runs: 1
- Stages pumped: 1

- Hours of operation: 44

Operational Work Scope. Leak detection within the horizontal section of the wellbore:

- Length of interval inquiry: 10,258 ft
- Maximum deviation: 93°
- Logging events planned: 3
  - DTS: static wellbore condition
  - DAS: well allowed to produce
  - DAS: well injection stage

Operation Execution

A land CT unit was deployed to the wellsite with a fiber optic-capable 24,000 ft, 2 3/8-in. outer diameter (OD) CT work string. The CT unit was rigged up and pressure tested per standard API requirements, and the well was opened. The CT began RIH using a BHA comprised of an agitator, motor, and mill in conjunction with xanthan gel to clean the wellbore of any potential residual debris. The cleanout was continued until the CIBP was tagged to confirm depth. At this time, the CT pulled out of hole (POOH) 38 ft to help ensure the mill bit was off the CIBP and the injector and reel brakes were set. The well volume was then circulated out with 400 bbl of freshwater.

The process of circulating out the wellbore volumes creates a uniform temperature profile within the wellbore noticeably colder than the formation temperature for logging initiation. At this time, fiber-optic data recording began, and the well was shut in. The wellbore was heated by the surrounding reservoir, allowing for a base temperature profile to form. DTS data were collected for 5 hr and 21 min until the onsite technician was confident with the data trend. Once this shut-in distributed sensing test was completed, the well was opened, allowing it to flow for 25 min under its own pressure to acquire distributed acoustic flow data. After the flow test was performed, the well was shut in. A single stage of injection was performed at 4 bbl/min for 1 hr to supplement the collected free-flow DAS data previously collected. After 1 hr of injection, data collection was completed. The CT unit POOH and proceeded to rig down and leave the location.

Figure 2—2 3/8-in. CT fiber-optic unit injector head and pressure control stack.

Data Interpretation

The DTS log acted as the primary mechanism for leak identification. The process of circulating also cools down the wellbore to a uniform temperature, which allows for a baseline temperature that can be monitored for inconsistencies in the warm-back behavior while the well is allowed to warm. When the well is shut in, the warm back across the wellbore is measured using the fiber-optic cable. During this warm-back period, temperature was monitored throughout the horizontal; Fig. 3 shows this warm-back event. When analyzing the DTS trend during the warm back, existing identified wellbore conditions and construction are accounted for, and abnormality trends are monitored. The inconsistent warm back of the wellbore will then be filtered to identify specific depths to demonstrate a temperature change inconsistent with the warm-back profile of the remaining wellbore.

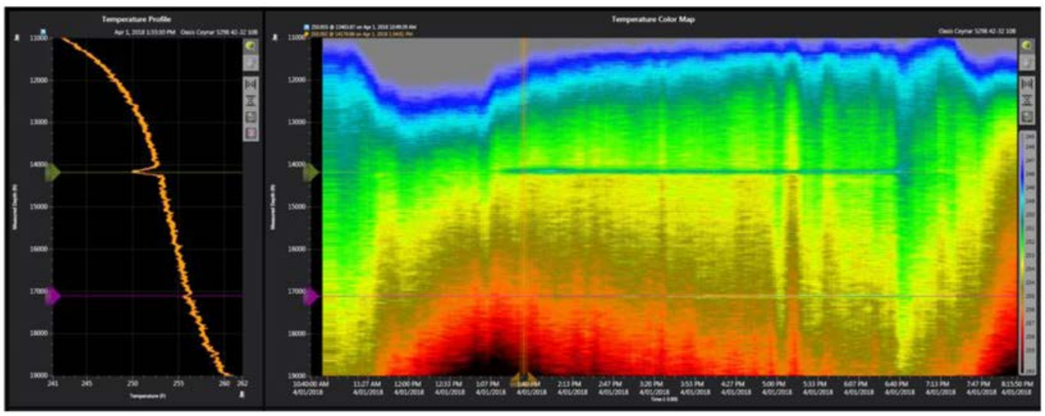

Figure 3—Temperature profile and color map.

The blue line on the right side of Fig. 3 demonstrates a reduced warm-back rate. The previous leakoff events during the well's initial stimulation, interventions, and CT cleanout reduced the temperature of the local reservoir area. When cooler-than-reservoir temperature entered the formation, it reduced the near-wellbore fluid and reservoir temperature. This reduced temperature can be monitored by the change in the light backscatter profile within the fiber. This correlates with specific depths when tracked over time for a shut-in or static well. The effects of the cool fluid leaking into formation can manifest as a cooler region than the warm back profiled of the entire wellbore.

The anomaly depths indicate casing failure and unplanned reservoir communication. Fig. 4 shows a smaller scale view of the primary leakoff expected by the operator. The reduced temperature spike correlated with a pipe collar joint suspected to be the primary cause of the leak, and the washed out collar was confirmed to be the primary point of leakoff. The 2.5°F variation was sufficiently large for a conclusive indication that communication with the reservoir was occuring before the static DTS test.

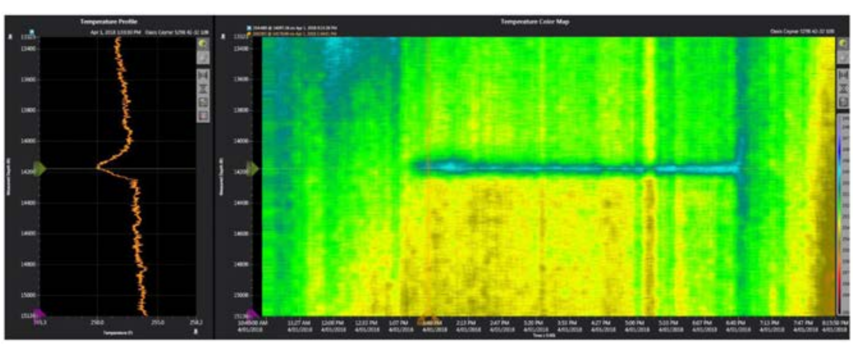

Figure 4—Reduced scale primary leakoff temperature profile and temperature map.

During the DTS log analysis, a second area was noted that exhibited reduced temperature increase as well; Fig. 5 clearly shows it on the left side. The same factors that drove the reduced temperature in the primary casing failure can cause temperature reduction in any area that communicates with the reservoir. One of the primary advantages of the DTS log compared to conventional leakoff detection methods is the lack of leakoff rate limitation. If communication with the reservoir is occurring, the insulating properties of the reservoir rock can help ensure a variation during warm back, even with minimal fluid volumes.

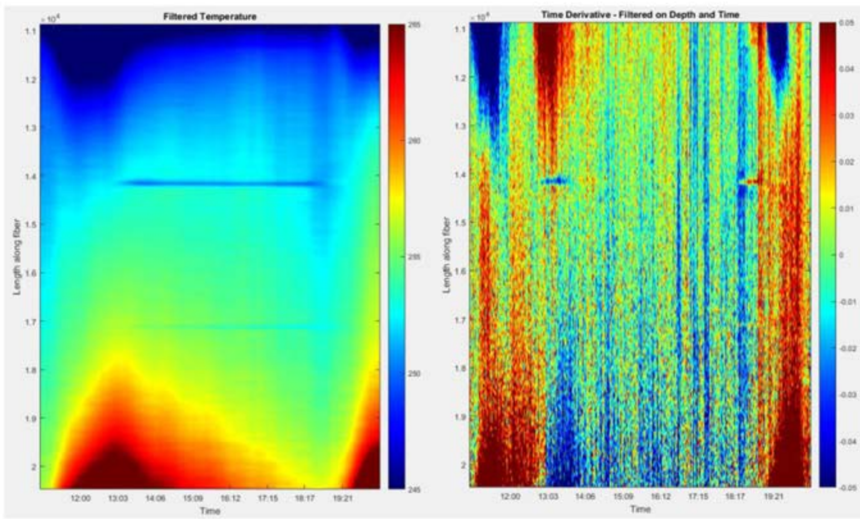

Figure 5—DTS time derivative lateral section.

Cleaning up data from Fig. 5 provides a clearer view of both leakoff points identified during the single static log event in Fig. 6. The second reduced temperature area also correlated with a known casing collar depth; however, before this log, the operator was not aware of the second point of leakoff. The second reduced temperature spike allowed the DTS log to identify a smaller point of leakoff that could have been missed using conventional logging and leak detection methods because of its reduced rate of leakoff and depth within the horizontal. Both leakoff points exhibited a reduced rate of warm-back temperature increase because of the cold fluid previously injected into the near-wellbore formation. The reduced rate of warm back was measured on fiber optic, and data were filtered to conclude leakoff depths.

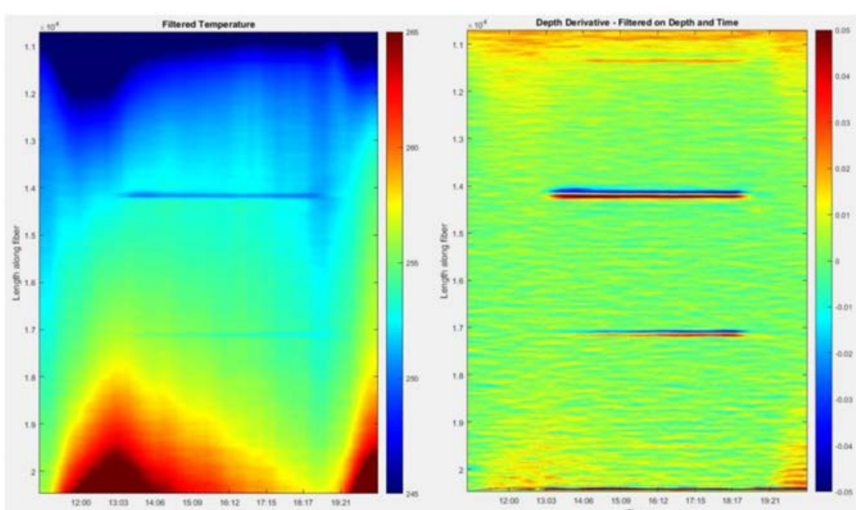

Figure 6—DTS depth derivative lateral section; filtered data set.

The analyst examining data remotely with the technician on location were able to complete a preliminary analysis during the static test in real time, and the decision was made to confirm the location using a DAS log. The well being allowed to flow causes vibration within the CT, and the fiber can be measured using the same light backscatter and interrogator laser as with DAS. This allows points of increased noise or acoustic events to be identified throughout the horizontal in real time. Fig. 7 shows the effect. This method of leak detection can only be used under conditions where a well is able to flow from the exposed reservoir. Because of the size of the primary leak, the DAS was able to capture a clear and conclusive acoustic event at the primary casing failure.

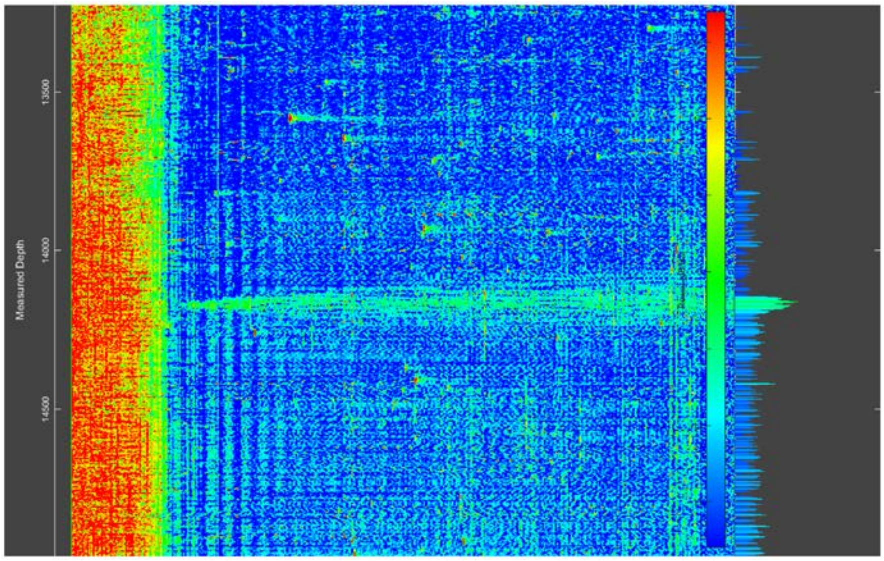

Figure 7—DAS signal during well open with lowpass filter.

The second leakoff within the well was unable to produce at a sufficiently high rate for an acoustic event to be recorded on DAS; the casing failure was too small to allow for significant reservoir flow. This further demonstrates the effectiveness of DTS in leakoff detection. Fig. 8 shows the reduced acoustic activity of the second casing leak.

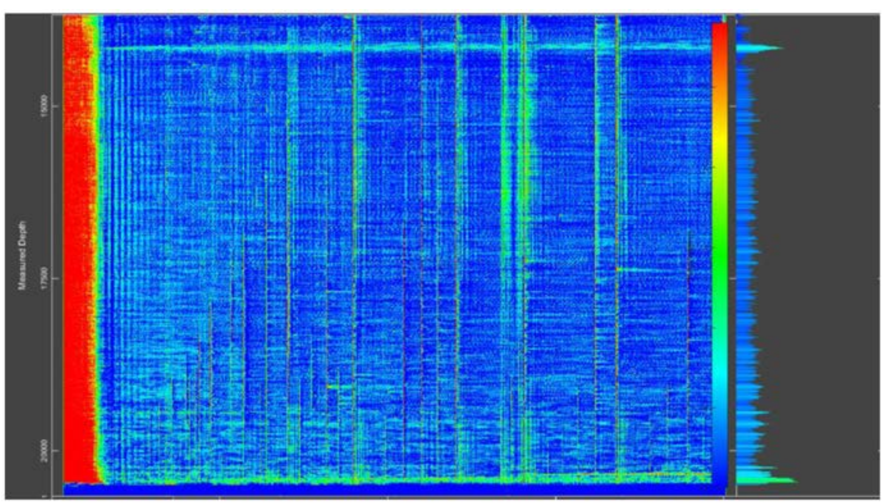

Figure 8—DAS signal during well open; no significant anomaly, 17,100 ft

The technician on location watched for significant acoustic activity across the wellbore in real time. The decision was made to perform a single injection pump stage at 7,000 psi to confirm the absence of a pressure-dependent leakoff, which are leaks that are only present during casing deformation events that occur at stimulation and completion pressure. The DTS would have registered these existing leaks on previous tests, but the operator requested the test while the unit was at depth.

Existing leakoff points can register as an anomaly while triple verifying depth. Fig. 9 shows the injection test. The only acoustic data registered were at the primary leakoff. The DAS was able to confirm the primary leakoff depth and demonstrate the minimal leakoff present at the secondary failure. The secondary leakoff rate was below what could be measured by the acoustic threshold. This confirms that the second leakoff would not have been successfully captured by acoustic or noise data alone.

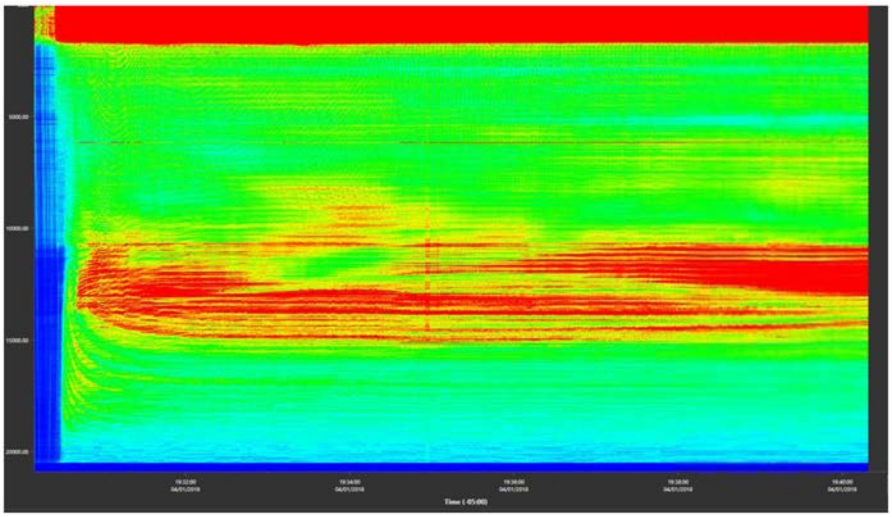

Figure 9—DAS during the injection stage.

Conclusions

A fiber optic-capable coil was run into the horizontal to log the target interval from the top of liner to the CIBP. This set the fiber-optic cable within the CT work string at a depth that allowed it to measure the entire interval of interest in real time. The well was cooled to a uniform temperature and then shut in; the wellbore was allowed to increase in temperature toward reservoir temperature. A static DTS test was performed that identified temperature anomalies at 14,178 and 17,110 ft because of the reduced temperature increase caused by the presence of cooler near-wellbore fluid previously injected. The well was then allowed to flow under its own pressure, and a DAS log was able to confirm the depth of the 14,178-ft casing leak. The production DAS log was unable to verify the second leakoff point because of the small rate of production at the casing failure. An injection test was performed to verify the absence of pressure-dependent casing leaks and the casing leak at 14,178 ft. The injection test was unable to verify the second leakoff point because of the small rate of injection at the casing failure. The casing leak at 17,110 ft did not register on the DAS logs.

The operator, who was made aware of both casing failures, used this information to redesign the stimulation treatment from the CIBP at 20,685 ft to the secondary leakoff point at 17,110 ft, allowing for improved stimulation placement. The casing leak at 14,178 ft was mitigated, and stimulation continued as planned from the heel to 17,000 ft. Using CT-conveyed fiber-optic DTS and DAS allowed the Bakken operator to identify known and unknown leaks in a single run and pumping stage. Therefore, the operator could mitigate the leaks and adjust the hydraulic fracture stimulation design to increase the effectiveness of the placed treatment.

References

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