PETROPHYSICS, VOL. 66, NO. 4 (AUGUST 2025); PAGES 000–000; 10 FIGURES. DOI:10.30632/

Pioneering Well Logging: The Role of Fiber Optics in Modern Monitoring for Well Integrity Diagnosis

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ABSTRACT

Maintaining well integrity is a critical aspect of safe, efficient, and economically viable oil and gas production. Traditional well diagnostic tools such as calipers and single-point acoustic and temperature logging have been used extensively to assess well conditions. However, these approaches often fall short when confronted with complex, intermittent, or distributed anomalies due to their inherent spatial and temporal limitations. These limitations can lead to ambiguous or inconclusive assessments, wasting valuable time and remediation costs.

This study presents a comparative analysis between these conventional approaches and the latest distributed fiber-optic sensing (DFOS) technologies. Specifically, we highlight the diagnostic power of distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) in two real-world field applications. In each case, traditional tools failed to isolate the source of tubing-to-annulus communication with precision. Fiber optics, on the other hand, provided comprehensive, real-time insights and enabled accurate localization of the anomalies within a fraction of the time (Johannessen et al., 2012; Silixa, 2022).

The integration of fiber-optic sensing not only delivered superior diagnostic clarity but also reduced the diagnostic timeline by over 85%. These results demonstrate that fiber optics represents a paradigm shift in well integrity assessment, transitioning from interpretive and reactive methodologies to real-time, high-resolution, and proactive diagnostics.

INTRODUCTION

Fiber optics, a technology that uses thin strands of glass or plastic fibers to transmit data as light signals, has revolutionized the way we communicate, transfer, and acquire information. Unlike traditional single-point measurements that rely on discrete sensors measuring the data at predetermined stations, distributed sensing utilizes fiber optics as the sensing element, providing full coverage of the logging interval throughout the survey duration and providing key information for understanding fluid dynamics. Caliper, along with single-point acoustic and temperature measurements, have been conventional methods for well integrity diagnosis. However, caliper data are affected by borehole conditions, and single-point measurements, due to their inherent requirements, require long hours for data acquisition and often miss events beyond the usual 10-ft scanning radius of the sensor. They are also susceptible to missing events that are not continuous or do not happen while the sensor is across that specific depth during that specific time. Since the sensor must physically move across the entire zone of interest, and the tool—particularly in the case of acoustic measurements—acquires data by station, the acquisition process typically takes about a minute per station. Stationary measurements are usually performed every 10 ft. This, in turn, comes to around 7 hours for acoustic measurement only (per condition). Also, most memory tools are deployed, which limits having real-time data also. Fiber optics, which uses the cable itself as the sensor, eliminates all this uncertainty while having the ability to livestream data. This reduces the final delivery, including acquisition and interpretation, by almost 60 to 90% in most cases (detailed calculation in the "Methodology" section). Since time and clear answers are of prime importance in well integrity assessment, fiber optics has a key role to play in modern well integrity monitoring.

This paper discusses the use of fiber optics for well intervention, detailing the methods and results from two examples for well integrity assessment.

OBJECTIVE

The primary objective of this study is to demonstrate the application and benefits of fiber optics in well integrity

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diagnostics. Through continuous real-time monitoring, fiber optics enhance operational efficiency by reducing data acquisition time, offering unprecedented insights into well integrity as compared to conventional methods of data acquisition. This is highlighted and showcased through two examples: in both cases, conventional diagnostic methods provided ambiguous results, while distributed sensing with fiber optics clearly identified and explained the source of communication between the tubing and the tubing-casing annulus (TCA).

METHODS/PROCEDURES/PROCESS

The two major hardware components of a fiber-optic sensing system consist of an interrogator and the fiber-optic cable itself.

An interrogator (Fig. 1) in fiber optics is a device used to read and interpret the signals transmitted through fiber-optic sensors. It plays a crucial role in converting the optical signals into meaningful data that can be analyzed and used for monitoring and decision making.

Fig. 1—Example of an interrogator.

The fiber (Fig. 2) acts as the physical medium for transmitting light signals. It is composed of a core (usually glass) surrounded by a cladding layer that ensures total internal reflection. Together, these components form a comprehensive fiber-optic sensing system, enabling detailed and accurate monitoring in various applications.

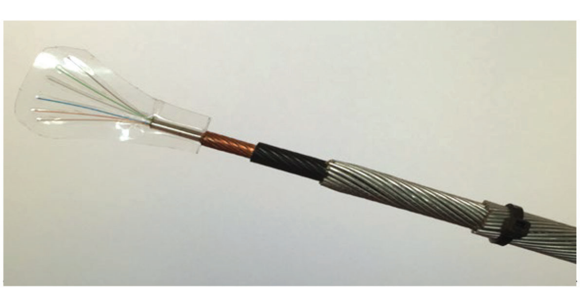

Fig. 2—Engineered fiber-optic wireline cable.

ADVANCEMENTS IN FIBER OPTICS

Figure 3 shows different types of fiber and illustrates the advancements that led to a 20-dB reduction in noise floor. This improvement made it possible to use distributed sensing for a range of well integrity diagnoses, including the detection of minor issues and support for intervention-based evaluations. The position of the laser pulse illuminating the sensing of the fiber along the length is shown by the two red rectangular pulses. Figure 3a shows standard fiber with small random fluctuations of the refractive index resulting in Rayleigh backscatter light with varying amplitude and phase. Figure 3b depicts highly doped fiber with a higher Rayleigh scatter cross section. Figure 3c shows continuous chirped fiber Bragg gratings to enhance backscattering compared to background Rayleigh. Figure 3d presents precision-engineered fiber with bright backscatter centers to control the amplitude and phase of reflected laser pulses.

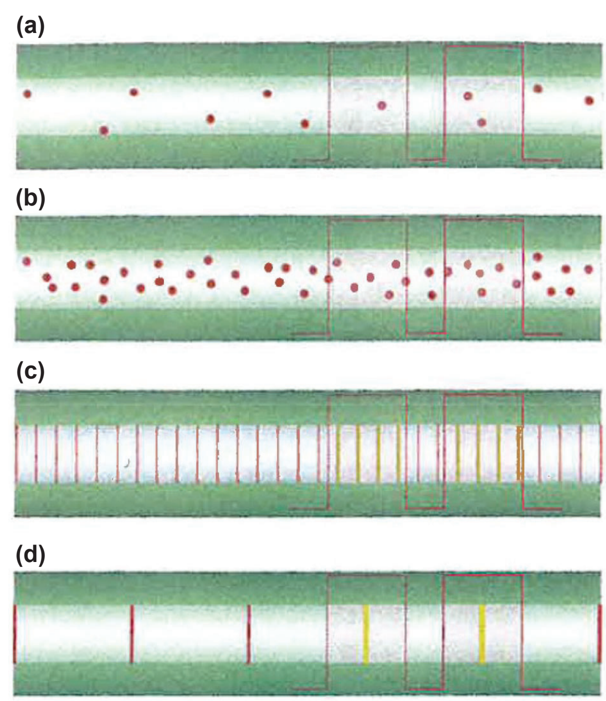

Fig. 3—Different manufacturing techniques for enhancing the backscattered light along a fiber.

One of the issues with standard fibers (Fig. 3a) is its very poor signal-to-noise ratio (SNR), making it very hard for leak events to be captured. It is very critical to capture the maximum signal from the backscatter to capture relevant information. There have been some advancements with highly doped fiber and continuous enhanced fiber where efforts are made to increase the signal level. The problem faced by doped fiber is the significant loss along with the increased signal, whereas, with continuous enhanced fiber, there is very little control over the phase relationship from multiple scatters. This is a huge limiting factor in using such fibers (Figs. 3b and 3c).

One of the main advancements in distributed fiber optics is the introduction of precision-engineered fiber (Fig. 3d), which provides a bright scatter center where the optical amplitude and phase of the return signal, along with the sensing fiber, are precisely controlled (US Patent App. No. 2018/0045543; EP Patent No. 3265757). In this case, we can reach shot-noise limited performance with the right distributed acoustic sensing (DAS) interrogator, resulting in a 20-dB improvement in performance down to sub-picostrain (pε)/√Hz resolution. Figure 4 is a plot of the frequency response of the DAS system (with a 10-m gauge length) using the standard single-mode fiber (green) and the precision-engineered fiber (red). In this case, the noise level of –80 dB rel rad/√Hz for the standard single-mode fiber corresponds to 2.5 pε/√Hz, and –100 dB rel rad/√Hz corresponds to 0.25 pε/√Hz. This corresponds to 100 times improvement (Farhadiroushan et al., 2017).

Combined with the right interrogator, the new advancement offers a significant improvement in DAS performance, with a 20-dB lower noise floor compared to what can be achieved with standard fiber, enabling the detection of even minor integrity issues, thus giving it a leading role in intervention-based well integrity diagnosis.

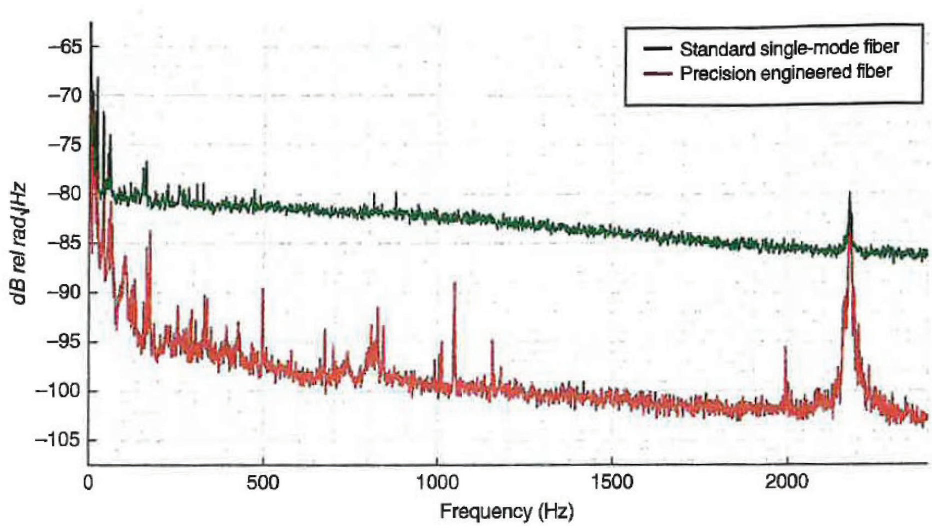

Fig. 4—The frequency spectra response of the distributed acoustic sensing (DAS) system (in a 10-m gauge length) using the standard single-mode fiber (green) and precision-engineered fiber (red).

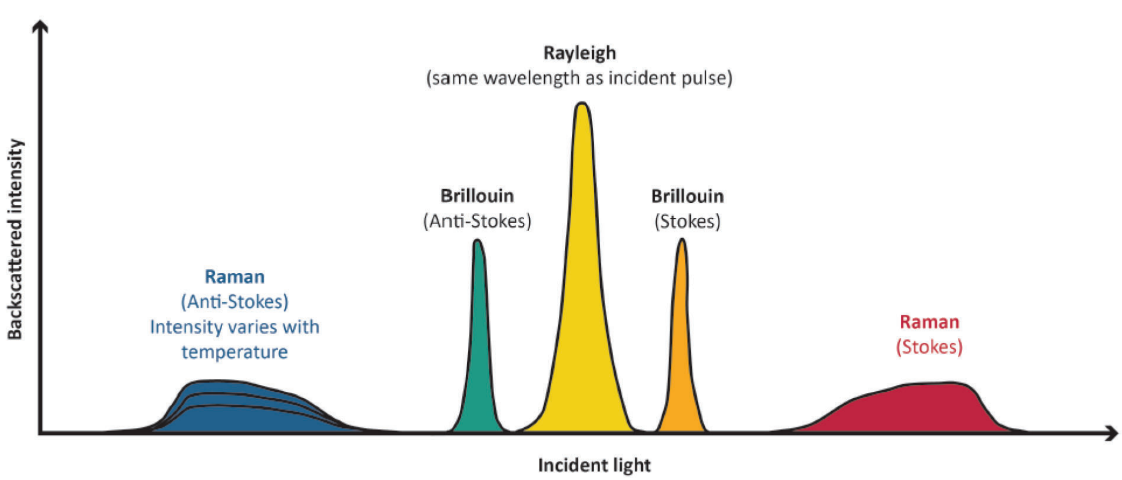

Fig. 5—Spectrum of backscattered light inside an optical fiber.

The outputs from the fiber-optic sensing system are below:

TEMPERATURE MONITORING

- Technology: Distributed temperature sensing (DTS) (Silixa, 2022).
- Principle: Utilizes Raman scattering to measure the temperature along the wellbore.
- Application: Continuous temperature data acquisition helps identify anomalies such as fluid migration or leaks. Temperature data can be observed along the well through time, providing critical information for well integrity.
- Implementation: Fiber-optic cables are installed along the wellbore. The DTS system sends a laser pulse down the fiber, and the backscattered light is analyzed to determine temperature variations along the length of the fiber. These data are then processed and visualized in real time (Dakin et al., 1985).

ACOUSTIC DATA MONITORING

- Technology: Distributed acoustic sensing (DAS).
- Principle: Based on Rayleigh scattering to capture acoustic signals along the wellbore.
- Application: DAS is used to detect and locate leaks, monitor cement integrity, and identify mechanical issues within the well. Acoustic data provide valuable insights into the operational status and integrity of the well.
- Implementation: Similar to DTS, fiber-optic cables are deployed along the wellbore. DAS systems send a series of light pulses down the fiber and measure the backscattered light caused by acoustic vibrations. These vibrations are analyzed to detect and locate anomalies such as leaks or mechanical failures (Johannessen et al., 2012).

METHODOLOGY ADOPTED TO CAPTURE WELL INTEGRITY EVENTS

A combined analysis of distributed temperature measurement and distributed acoustic measurement provides invaluable insights into the flow dynamics in the well. The ability to monitor the entire logged section is a very powerful method to understand the flow path and patterns.

The fiber-optic cable can be deployed in multiple ways for diagnosis based on requirements and/or specific scenarios (permanent/intervention-based).

Inside tubing (Fig. 6a): Deployed inside the tubing, which is retrievable with the lowest cost. Fiber-optic wireline/slickline/coiled tubing conveyed through tubing

Fiber-optic cable clamped outside screens (Fig. 6b): This is challenging when completions are multistage as a downhole wet connect is required.

On tubing (Fig. 6c): Clamped to tubing. This kind of deployment can be viewed as a semipermanent measurement.

On casing/cemented behind casing (Fig. 6d): Clamped to the outside of the casing. This type of fiber installation can be used as permanent monitoring in downhole or subsea applications with the highest cost and data quality (Naldrett et al., 2018).

A logging procedure is designed to capture information most relevant to achieve the well integrity objective. The survey is planned with a baseline to understand the reference and is used as a benchmark to analyze the dynamic well conditions. The well is manipulated to initiate flow events that could have caused the well integrity problem. Capturing the flow events during these dynamic conditions across the entire logging section and comparing them with the events/non-events during baseline conditions provides invaluable information about possible well integrity issues.

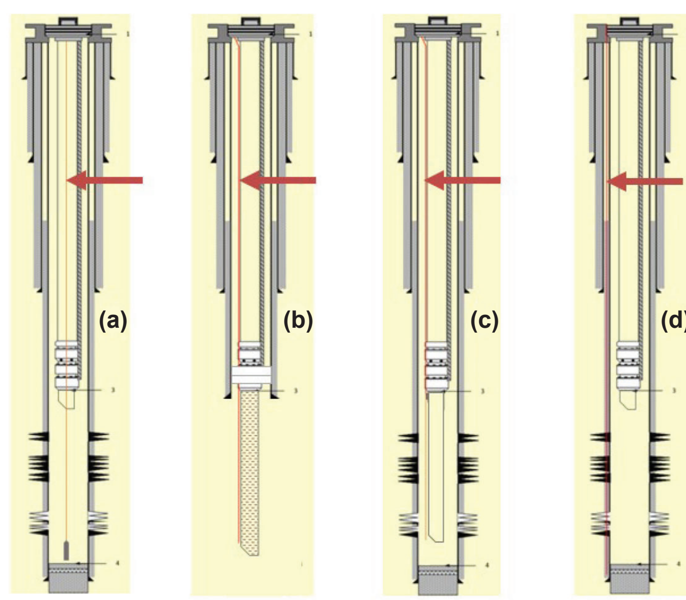

Fig. 6—Different methods of fiber deployment (red arrow points to fiber (in red color)).

The logging procedure is tailored to the objective of each survey. Since the cable itself is the sensor, it is also possible to connect any wireline tools, like spinner, corrosion logging tools, etc., below the cable and acquire data in the same run. After running in hole with all suggested sensors and reaching holdup depth (HUD), depth matching is done. All the next steps of data acquisition will be based on the well condition as the cable will record data from surface to HUD with no further intervention required. Usually, the first step is baseline acquisition, where the well is shut in, including annuli, with no activities for a prolonged duration of time. This baseline measurement will be a reference to further changing conditions and will act as a reference for interpretation. Based on the objective, further steps are designed to manipulate the well by bleeding off respective annuli or injection, etc. These steps are designed to create flow and thus identify any possible integrity issues. The duration of each step is typically 2 hours only. For a typical survey with one annulus investigation with a bleedoff pass, the duration of the survey is around 6 hours only. Comparing this to conventional stationary single-point measurement, which would take around 24 to 48 hours depending on the logging interval, shows the power of distributed fiber optics. Because the data are available in real time, decisions can be made on the spot to increase or decrease the duration of data acquisition and to dynamically add or remove steps in the acquisition process. This flexibility is invaluable. A hypothetical well with a measured depth of 15,000 ft and a single sustained annulus pressure issue is used here as an example to illustrate the time savings in data acquisition.

Logging interval: 15,000 ft
Logging steps: Baseline, bleedoff, buildup

Time Taken for Acquisition Single-Point Measurement

- Down pass temperature measurement time (assuming 30 ft/min): 8 hours 20 minutes per condition
- Up stationary acoustic measurement time (assuming 10 ft station and 1 minute per station): 25 hours per condition
- Total logging time per condition: 33 hours 20 minutes
- Total logging time for the entire survey (three conditions): 100 hours or 4 days and 4 hours

Time Taken for Acquisition Fiber Optics

- Run-in-hole (RIH) time (assuming 30 ft/min): 8 hours 20 minutes (one time)
- Baseline data acquisition: 2 hours
- Bleedoff data acquisition: 2 hours
- Buildup data acquisition: 2 hours
- Total data acquisition time: 14 hours 20 minutes

Time saved = 85 hours 40 minutes.

APPLICATION SCENARIOS

Throughout the life cycle of a well, various integrity issues can arise. Common well integrity problems where fiber optics can be effectively deployed include identifying sources of sustained annulus pressure, confirming packer integrity, pinpointing leak locations, and detecting behind-casing channeling. Understanding these issues is crucial for assessing the well's integrity status and, in some scenarios, putting the well back under production/injection, which was shut in due to a well integrity issue. Targeted workover activities can be performed only if there is a clear understanding of the flow dynamics causing the well integrity concern. This can be achieved by diagnosis using fiber optics.

Poor cementing can lead to hydrocarbons or water migrating to the surface, potentially creating sustained surface pressure, which poses a significant safety concern. Additionally, packers intended to provide isolation may fail to hold, compromising well integrity. Identifying precise leak points in the tubing or casing is essential for accurate diagnosis and effective workover planning. All these well integrity issues are some of the practical application scenarios for DTS/DAS fiber-optic well integrity diagnosis.

EXAMPLES OF APPLICATION

Example 1

Below is a global example where the use of the DAS-DTS combination evaluated a suspected tubing leak in a deviated oil producer with a gas lift (Fig. 7). During pressure testing, tubing to TCA communication was detected. Due to the integrity issue, the well stopped flowing efficiently, leading to a loss of production. It was imperative to understand the integrity issue and bring the well back to production.

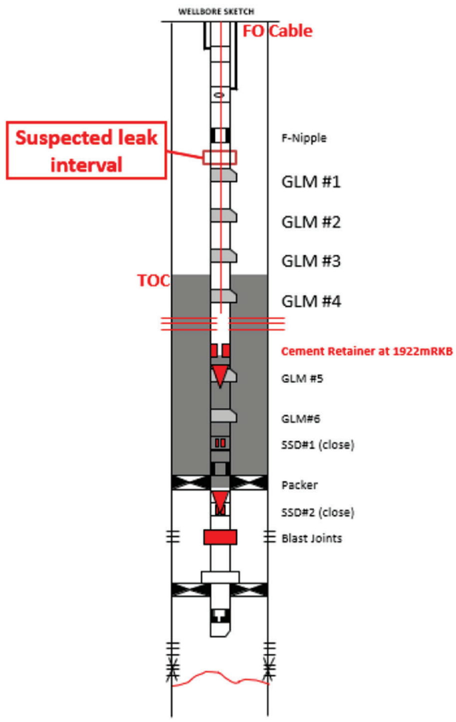

Fig. 7—Example 1: Well schematic with gas lift mandrel (GLM).

As a part of the initial investigation, a multifinger caliper was run to identify the reason for tubing to TCA communication. Caliper results provided a suspected interval of around 200 to 300 m as the source of communication (marked in red in Fig. 5). Since exact depth intervals couldn't be identified from the conventional diagnostic method, it was decided to run fiber optics to identify the source of communication. Distributed sensing was chosen over the conventional single-point acoustic and temperature to save time on data acquisition.

Data acquisition was planned in multiple well conditions. DTS-DAS data were acquired initially during shut-in conditions. This measurement is a baseline/reference for changing well conditions. Other flow conditions were created to activate the leak path.

Figure 8 shows the acquired data during the well condition where tubing (TBG) was closed, and there was a gas injection into TCA. The first column shows the measured depth in meters. The second column shows the well deviation in degrees. The third column shows a well schematic with the location of gas lift mandrels (GLM). Form refers to the formation tops. The fifth column highlights the DTS traces averaged for a specific duration of time during each well condition. The duration of averaging can be customized based on the requirement, thus allowing to visualize and identify any anomalies in temperature. DTS traces during different well conditions show clear changes in gradient across 520 m and 660 m, suggesting a possible integrity breach at those depths.

Low-frequency DAS shows clear anomalies correlating to the temperature gradient changes. Clear signs of fluid

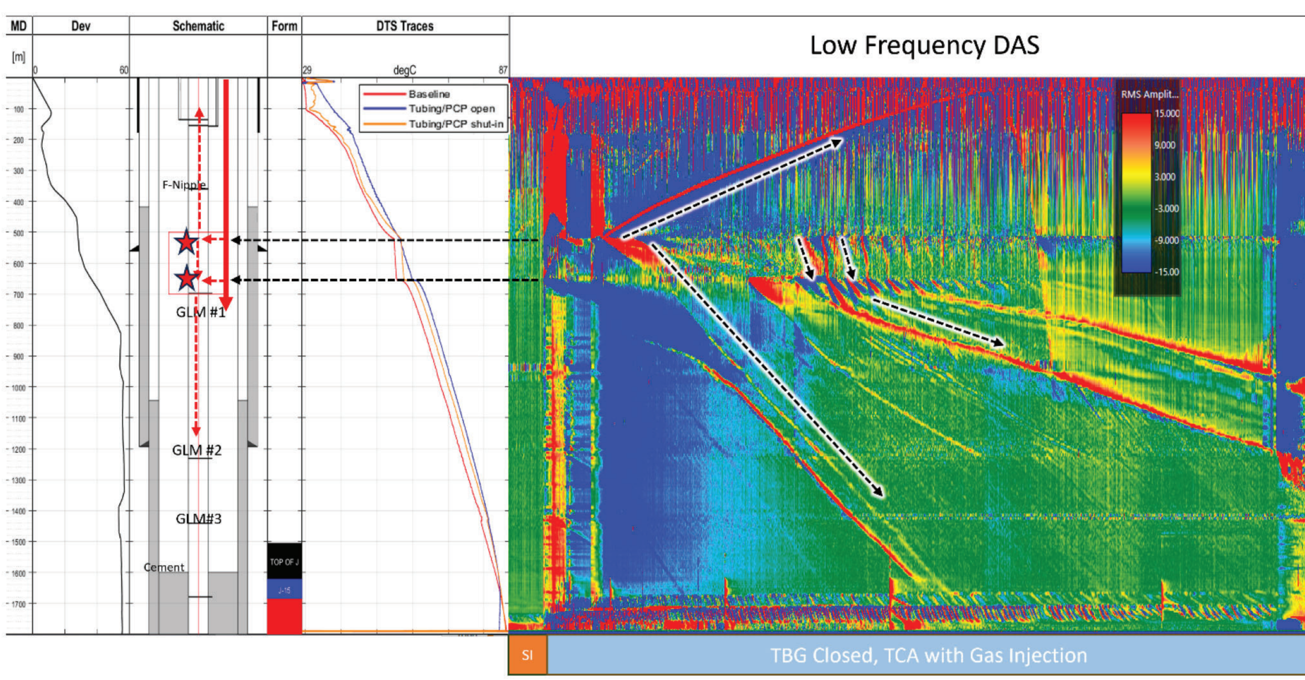

Fig. 8—Example 1: Well deviation, well sketch, formation tops, DTS traces, and low-frequency DAS.

movement can be traced from both depths. An upward movement can be tracked after injection into TCA starts. There are also signs of downward movement, which starts immediately after the upward movement. Strong signs of downward movement can be tracked from 660 m, where the second temperature anomaly was identified. The anomalies in DAS and DTS suggested a possible integrity breach across 520 m and 660 m.

A combination of both allowed the identification of depths on integrity breach, and fluid path identification was possible using low-frequency DAS.

Fiber optics not only identified the precise depth of leaks, which allowed for targeted mitigation, but also provided those results in significantly less time. The workover was done based on the results, and the well was brought back on production.

Example 2

In another global example, an oil producer using gas lift suspected communication between the tubing and the TCA due to a tubing leak. The well ceased to flow with gas lift, thereby resulting in production loss. Conventional single-point measurements, along with a multifinger caliper, were run to identify the leak. Multiple intervals were identified to have a high degree of penetration using a caliper. Single-point acoustic measurement showed some level of correlation between high penetration intervals and suggested suspected leak points across certain intervals only. Unfortunately, there was some level of uncertainty on certain intervals. It needed to be confirmed if the remaining intervals were leaking so a clear workover plan could be made.

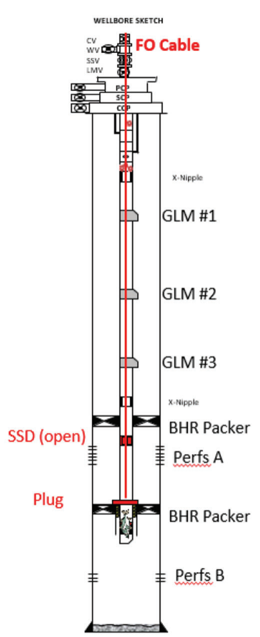

Fig. 9—Example 2: Well schematic with GLM.

Fiber optics were deployed using wireline to identify the leak points so a much-informed workover plan could be made. Fiber-optics data acquisition was planned under various conditions to ascertain the leaking intervals. Baseline data were recorded as a reference to changing well conditions. Various dynamic conditions, like TCP closed-progressive cavity pump (PCP) injection, bleedoff, and TCP open-PCP gas injection, were done to have a full understanding of well/leak behavior.

Figure 10 shows the well deviation, schematic, formation tops, baseline acoustic spectrum, acoustic spectrum during tubing flowing with gas lift, and DTS traces during the various well conditions. DAS spectrum during baseline shows acoustic activity across 480 m where DTS traces start diverging from baseline, showing a clear indication of integrity breach across that depth. Additionally, during well flow with gas lift, acoustic activity was observed at multiple depths. These were accompanied by DTS traces showing gradient changes at each location, suggesting possible integrity breaches. The acoustic events and corresponding temperature anomalies were recorded at approximately: (a) 280, (b) 320, (c) 360, (d) 370, (e) 380, (f) 430, (g) 440, and (h) 490 m. Thus, a combined analysis of DTS and DAS has provided a clear understanding of suspected leak intervals. The ability to scan the entire logging interval at the exact same time has enabled such a diagnosis, which means no acoustic activity is missed.

With a clear understanding of all the leaking intervals and better correlation with caliper data, a much more confident plan could now be prepared for workover. A targeted mitigation plan was made to fix the leaking intervals, and the well was brought back to production later.

Based on the above two examples, it is clear that fiber optics provide a precise understanding of the well integrity issue under investigation, thereby providing actionable information for targeted remediation as compared to conventional methods.

FINDINGS

Enhanced Monitoring: Fiber optics provide continuous and real-time monitoring, offering full coverage of the interval throughout the entire operation. This comprehensive monitoring capability ensures that any issues are detected

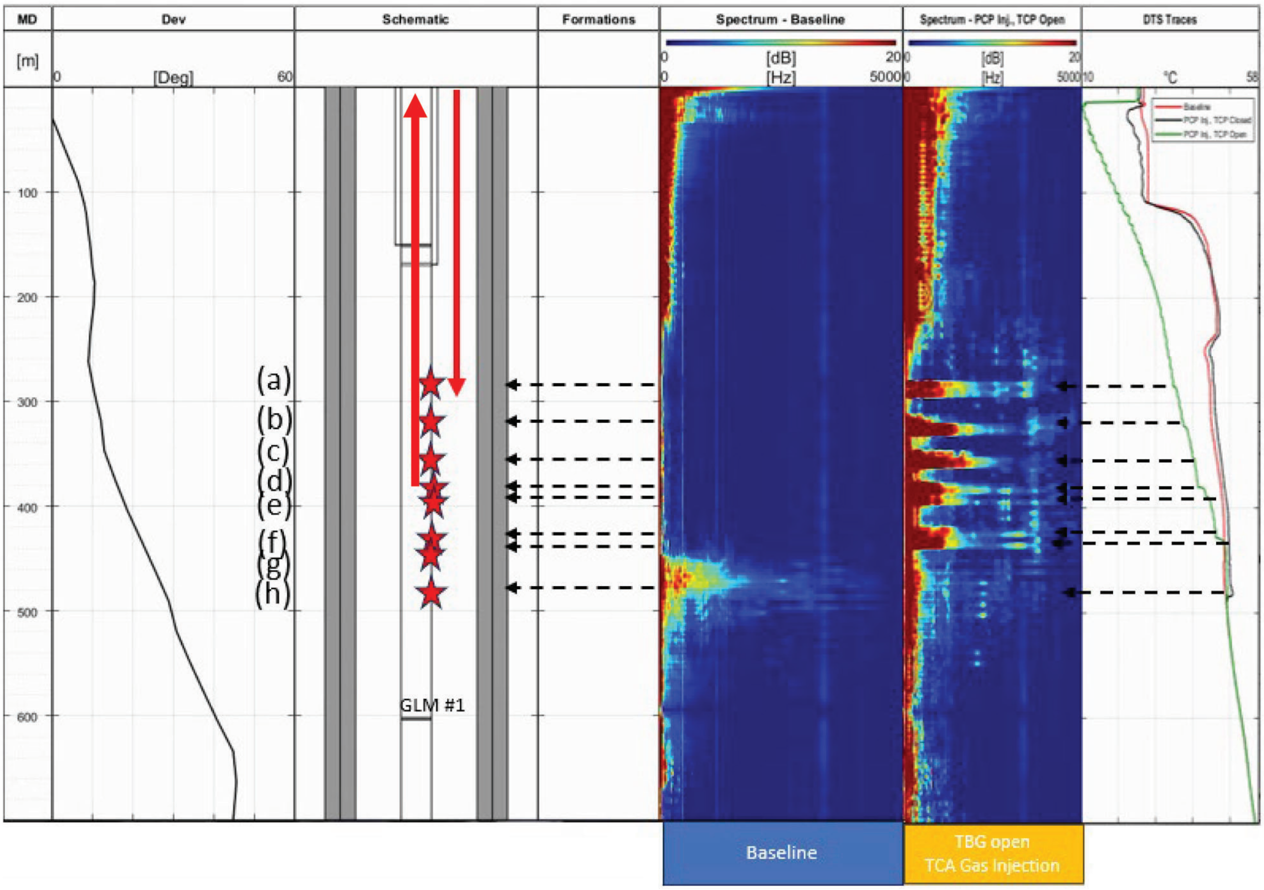

Fig. 10—Example 2: Well deviation, well sketch, formation tops, DAS spectrums (baseline and dynamic), and DTS traces.

promptly and that nothing is overlooked, giving confidence in the system.

Improved Detection: Advancements in technology have led to superior SNR and lower noise floors, allowing the detection of quiet or low-frequency leaks. This improvement in detection capabilities enhances the overall safety and efficiency of well operations (Naldrett et al., 2018).

NOVELTY

The novelty of this work begins with the deployment of precision-engineered fiber, which offers a 20-dB improvement in SNR compared to standard single-mode fiber. This substantial enhancement enabled the detection of subtle, low-energy downhole responses—such as intermittent flow activity and minor leak pathways—that would otherwise remain undetectable using conventional fiber or traditional logging techniques. For the first time in the evaluated wells, dynamic flow features and communication events could be identified with high spatial resolution under real-world well conditions with a much faster turnaround as compared to other well integrity diagnostic techniques.

Two field case studies illustrate how this methodology was employed to resolve persistent inter-string fluid communication. In both wells, conventional diagnostics (e.g., multifinger caliper, single-point acoustic/thermal logging) yielded non-conclusive results, unable to isolate the depth or nature of flow anomalies. The presented approach used real-time, condition-responsive logging sequences where DTS and low-frequency DAS were jointly analyzed to precisely identify leak intervals, capturing both transient and persistent behaviors (Mahue, 2022).

The methodology introduced here—comprising baseline-pass benchmarking, condition-induced dynamic passes, and real-time visualization feedback loops—enables a shift from interpretative uncertainty to diagnostic clarity. This represents a fundamental advancement in how distributed fiber optics are operationalized for intervention, moving beyond monitoring into the domain of actionable, high-confidence diagnostics in real-world well conditions.

CONCLUSIONS

The field applications presented in this study underscore the transformative diagnostic potential of distributed fiber-optic sensing when deployed within a methodologically engineered acquisition and interpretation framework. The integration of DTS and DAS with dynamic well conditioning enabled spatially continuous insight into flow anomalies that had previously eluded traditional evaluation methods.

In both case studies, the fiber-based approach delivered quantitative confirmation of leak intervals and directional flow patterns, enabling precise workover execution. In one scenario, dual anomalies were characterized through continuous acoustic measurements correlating with thermal shifts, allowing the operator to isolate the breach zones with certainty. In another scenario, multiple suspected leak zones were ruled out with confidence, streamlining the remediation scope.

From an operational standpoint, the approach achieved an 85% reduction in diagnostic time—compressing survey durations from over 100 hours to less than 15—while concurrently improving the fidelity and confidence in the diagnosis. The ability to capture evolving downhole dynamics in real time across the full well length removes the spatial and temporal constraints inherent to single-point tools.

This work not only validates fiber-optic sensing as a high-resolution diagnostic platform but demonstrates its readiness as an intervention enabler, offering a scalable methodology for complex well environments where conventional tools are insufficient. It redefines the operational utility of distributed sensing by transitioning from passive monitoring to proactive subsurface diagnostics, with tangible outcomes in asset performance, risk reduction, and decision confidence coming from full coverage and continuous monitoring.

NOMENCLATURE

Acronyms

DAS = distributed acoustic sensing
DFOS = distributed fiber-optic sensing
DTS = distributed temperature sensing
GLM = gas lift mandrel
HUD = holdup depth
PCP = progressive cavity pump
RIH = run in hole
SNR = signal-to-noise ratio
TCA = tubing-casing annulus

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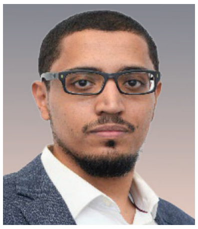

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Vishnu Raveen is a geoscience team leader at Silixa (A Luna company), specializing in distributed temperature and acoustic applications in various domains like well integrity, flow profiling, fracture assessment, etc. He previously worked with TGT in various capacities across the Middle East and India. Vishnu holds a master's degree in petroleum engineering from Heriot-Watt University (2014) and a bachelor's degree in mechanical engineering from Manipal University India (2013).