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Carbon Capture and Storage Monitoring with Distributed Fiber Optic Sensing

FEBRUARY 2024

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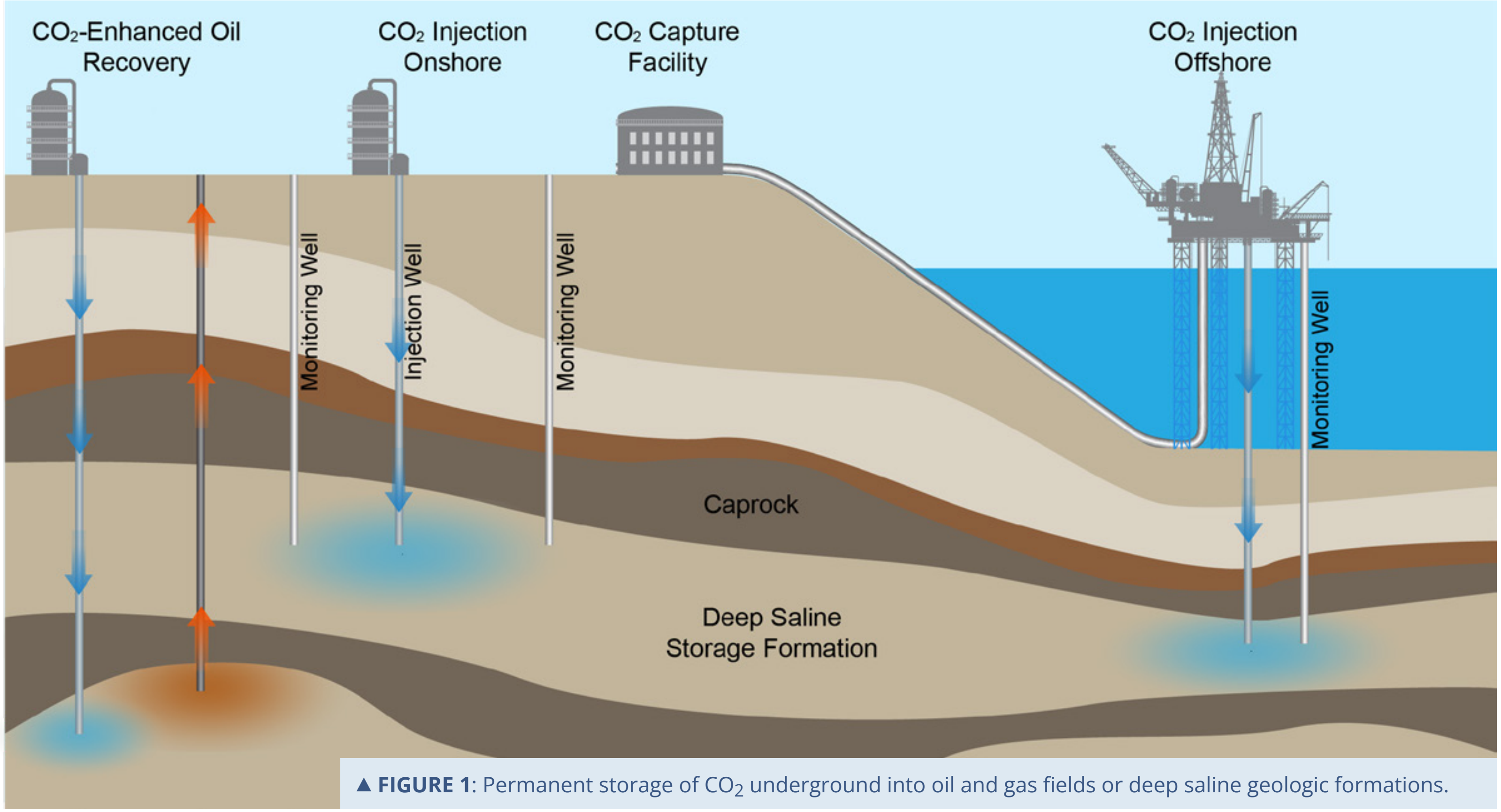
Carbon Capture and Storage: Introduction and Risks



▲ **FIGURE 1**: Permanent storage of CO_2 underground into oil and gas fields or deep saline geologic formations.

According to the U.S. Environmental Protection Agency, carbon dioxide (CO_2) is the primary greenhouse gas emitted through anthropogenic sources.

In 2018, CO_2 accounted for about 81.3 percent of all U.S. greenhouse gas emissions from human activities. The main source of anthropogenically generated CO_2 emissions is the combustion of fossil fuels (coal, natural gas, and oil) for energy and transportation, although certain industrial processes (cement, steel, and chemical production) and land-use changes also emit CO_2.

Carbon capture and storage (CCS) technology offers an opportunity to reduce CO_2 emissions to the atmosphere. The process consists of capturing CO_2, for example, from coal-fired power plants, before it enters the atmosphere; transporting the CO_2 via pipeline; and injecting it underground into depleted oil and gas fields or deep saline geologic formations, where it can be securely stored (**FIGURE 1**).

Carbon dioxide is injected using dedicated wells in deep geologic formations for long-term storage. In the United States, these wells are known as Class VI wells (USEPA, 2010), which require extensive subsurface characterization, including observations from previously drilled boreholes and indirect data from geophysical methods.

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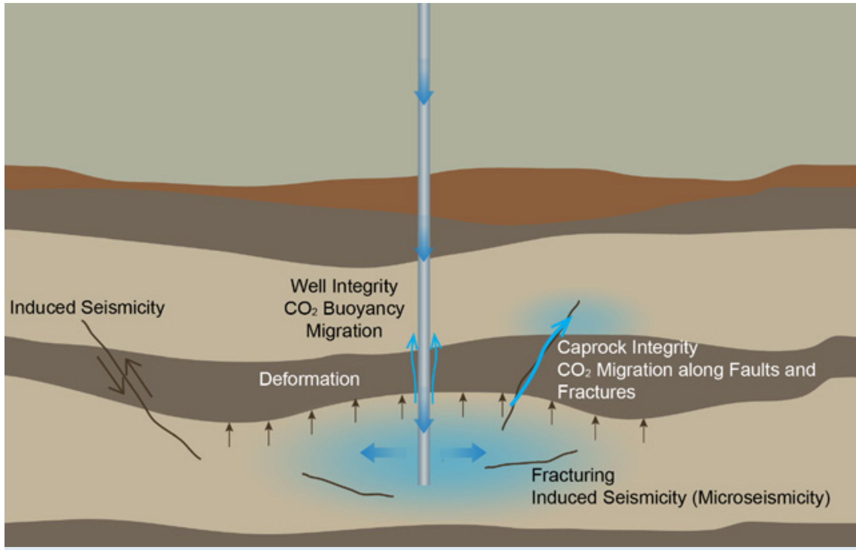
Carbon Capture and Storage: Introduction and Risks

A series of monitoring requirements exists during operation of a Class VI well for CO_2 injection. These requirements focus on mitigating risks arising from the injection of large volumes of CO_2 under high pressure in deep reservoirs (**FIGURE 2**). The evaluation of storage performance and containment is captured under the testing and monitoring (TM) framework.

The main risks identified are:

- **Well integrity**: Problems with well cementation can cause leakage of CO_2 upward to shallow aquifers or the surface.
- **Migration of CO_2 along faults and fractures**: This could eventually lead to CO_2 leakage to shallow aquifers and the atmosphere.
- **Migration of CO_2 plume outside of the storage reservoir**: It is important to track the free-phase CO_2 plume distribution during CO_2 injection to ensure it is confined to the permitted storage interval and, after injection operations have ceased, to provide assurance that the plume has stabilized.
- **Induced seismicity**: Although extensive characterization and planning for Class VI wells are undertaken, injecting large volumes of CO_2 can create fractures and/or activate preexisting geological faults generating microseismic and seismic events. Continuous monitoring is important because these events can be informative and a precursor to potential leakage pathways and/or damage to infrastructure.
- **Deformation:** CO_2 injection could lead to a significant surface heave due to the pressure buildup in the reservoir and the buildup of injected CO_2.

The mitigation of risks involved with CO_2 storage underground is possible with detailed site characterization and advanced monitoring before, during, and after the injection period. Fiber optic distributed sensing methods can greatly advance the spatial and temporal resolution of the data acquired during the characterization and monitoring phases, while reducing overall monitoring costs when compared to standard methods using point transducers such as geophones, temperature, and pressure gauges. This report aims to present an overview of fiber optic distributed sensing technology, an introduction to the relevant instrumentation, and the sensing fiber optic cables and applications. The report describes the fiber optic downhole and surface deployment possibilities for temperature, strain, and acoustic data acquisitions. The data are used for reservoir characterization using reflection and refraction seismic, plume detection with time lapse seismic, detection and location of microseismic events, subsidence, well integrity, and leak detection. Applications can be extended to flow assurance, injectivity profile and monitoring transportlines for leaks.



▲ **FIGURE 2**: Processes during active CO_2 injection into deep sedimentary formations and risks arising from the injection (Rutqvist, 2012).

Deployment of fiber optic sensing has a minimal environmental impact and provides large spatial coverage with no power requirements along the sensing cable.

Reservoir characterization capabilities and the short- and long-term monitoring applications for CCS projects are described. Finally, an overview of case studies is presented, highlighting the results and insights gained by applying distributed sensing methods in CCS projects.

2

Enabling Technology

2.1 Introduction

Distributed sensing enables continuous, real-time measurements along the entire length of an optical fiber with a maximum range of tens of kilometers.

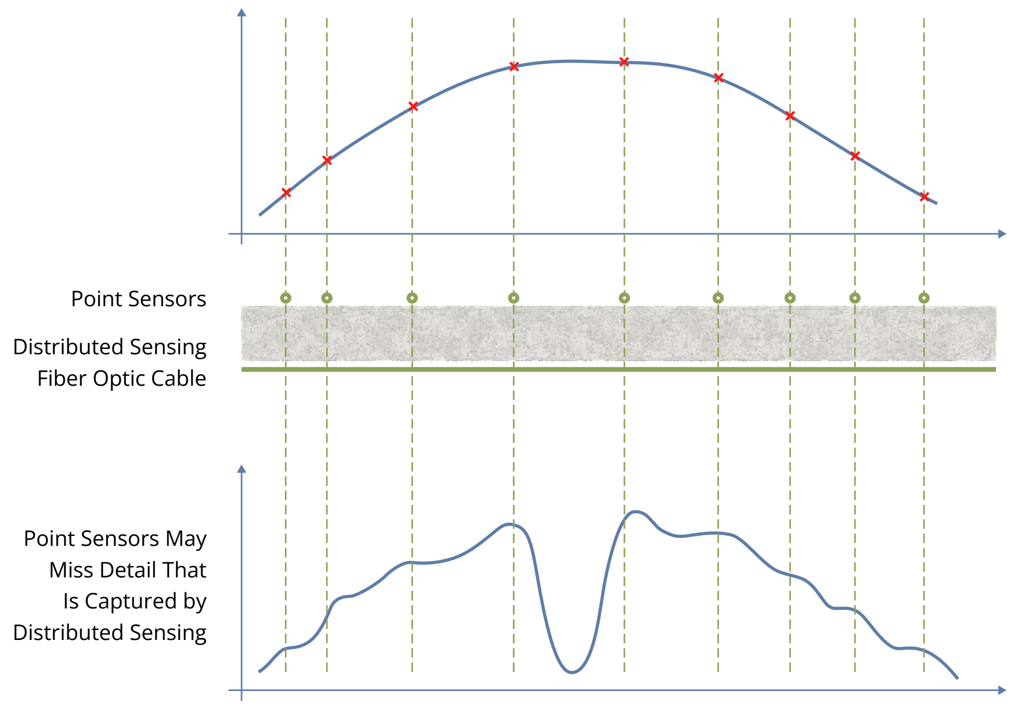
Unlike traditional sensing that relies on discrete sensors measuring at predetermined points such as geophones, distributed sensing utilizes the optical fiber as the sensing element without any additional transducers in the optical path (**FIGURE 3**). Fiber optic cables can be deployed on the surface or in boreholes either as permanent installations or temporary retrievable solutions.

A significant advantage of a cable permanently installed and grouted along the outside of a borehole casing is that it allows the collection of data while the well is operating, and simultaneously, the application of other methods and surveys in the well. This enables the installation in both injection and monitoring wells. In offshore wells, the cable can be strapped on the injection tubing.

A fiber optic distributed sensor emits pulses of laser light into an optical fiber. A portion of the emitted laser light is scattered within the fiber because of a variety of material-related attenuation mechanisms. The sensing principles rely on the backscattered light detected by the interrogators.

Characteristics of the light returning to the sensor are used to derive measurements of different physical properties along the optical fiber. The positional information along the fiber is determined from the time of flight between the emission of a laser pulse and the detection of backscattered light through application of the principles of optical time-domain reflectometry (OTDR).

▶ **FIGURE 3**: Spatial distribution plots illustrating the data gaps inherent in point sensor applications (above) compared to distributed sensor technology (below).



2.1

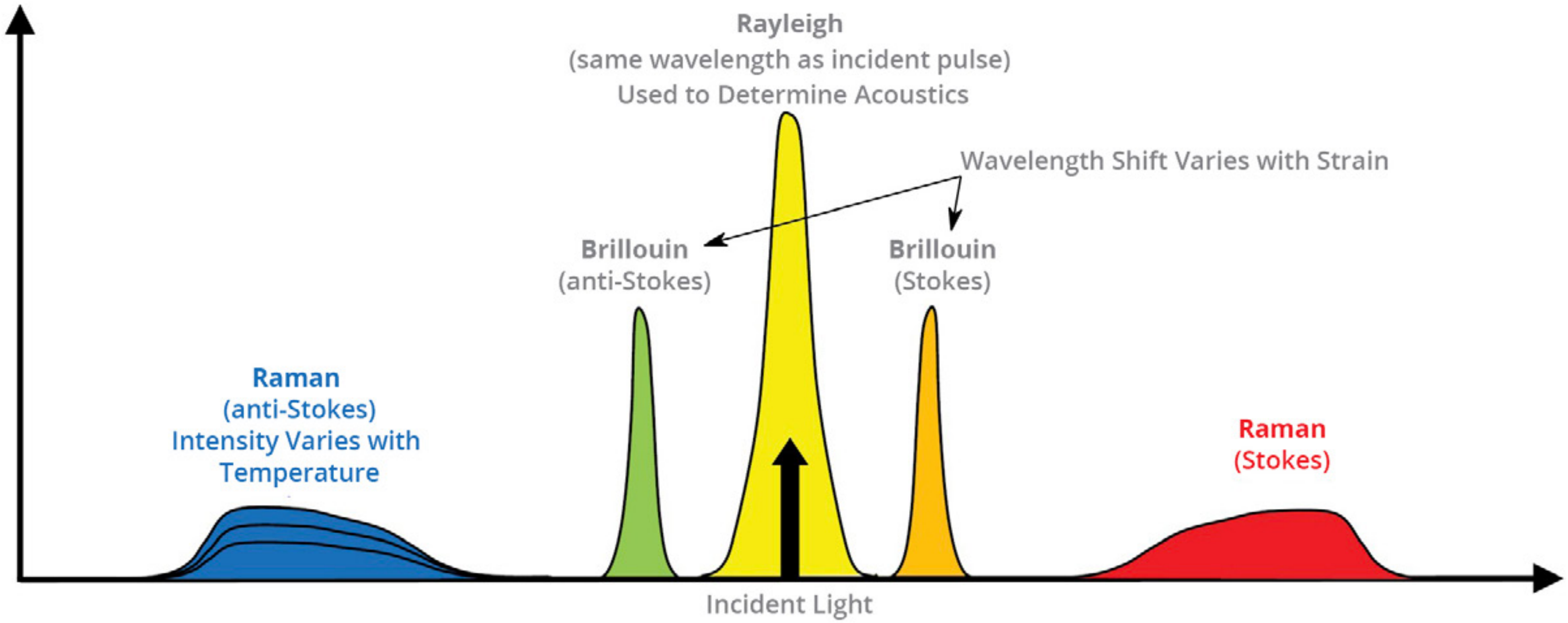
Introduction

Several scattering processes take place when the pulse of laser light interacts with the molecules of the optical fiber, and different measurements can be derived from analyses of the detected spectrum of light (**FIGURE 4**).

Most of the emitted light is backscattered without experiencing a change in wavelength through elastic Rayleigh scattering. True distributed acoustic sensors (DAS) use the Rayleigh scattering signal to derive the coherent full acoustic field (i.e., amplitude, wavelength, and phase) over a wide dynamic range allowing for characterization of localized acoustic environments.

Distributed temperature sensors (DTS) make use of wavelength-shifted backscattered light caused by inelastic interactions between the source light and temperature-dependent molecular vibrations within the fiber, known as Raman scattering.

Distributed strain sensors (DSS) use the interaction of emitted light with lower-frequency molecular vibrations (also referred to as material waves) within a fiber, known as Brillouin scattering, to derive the distribution of coupled strain across the entire length of the fiber.



▲ **FIGURE 4**: The spectrum of backscattered light inside an optical fiber includes (A) Rayleigh, utilized by DAS; (B) Raman, applied with DTS; and (C) Brillouin scattering, associated with DSS.

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2.1

Distributed Temperature Sensing (DTS)

2.2.1. Sampling and spatial resolutions

DTS instruments use Raman scattered light and the principles of OTDR to determine the temperature at each sampling point along an optical fiber.

A DTS unit launches a short pulse of light into an optical fiber. The forward propagating light generates Raman backscattered light at two new wavelengths from all points along the fiber.

The wavelengths of the Raman backscattered light differ from the forward propagating light and are named Stokes and anti-Stokes, according to the energy level measured for the absorbed photons (Stokes, if the energy is higher than the emitted photons; anti-Stokes if it is lower) (**FIGURE 4**). The amplitudes of the Stokes and anti-Stokes light are monitored by the DTS unit, and the spatial localization of the backscattered light is determined through knowledge of the propagation speed inside the fiber.

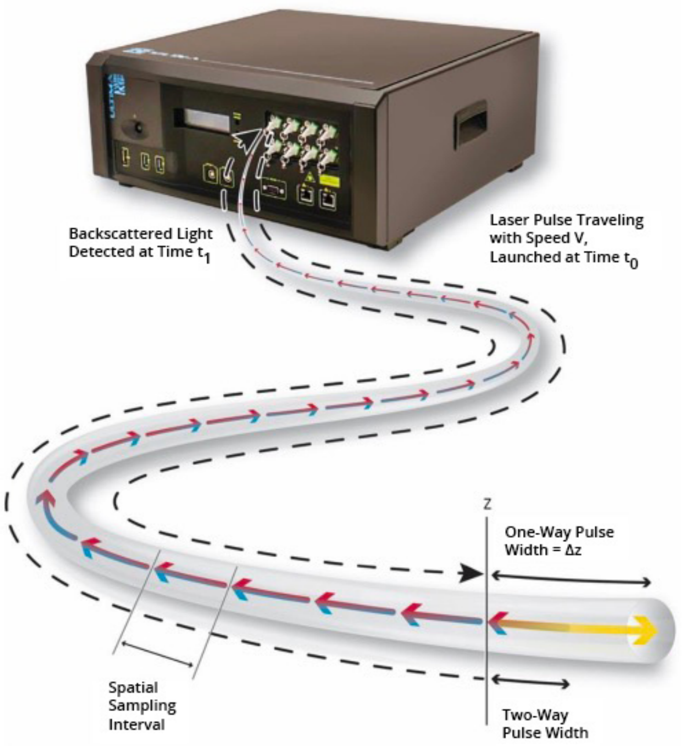
The determination of the source of light signal by measuring the time between the injection of a light source and the detection of a backscattered signal is the fundamental principle of OTDR. The amplitude of the Stokes light is very weakly dependent on temperature, while the amplitude of the anti-Stokes light is strongly dependent on temperature (**FIGURE 4**). The temperature at each sampling location is calculated by taking the ratio of the amplitudes of the measured anti-Stokes and Stokes light.

For more details about the DTS fundamentals, we recommend the reader to access "Introduction to Distributed Temperature Sensing" (Silixa, 2020).

2.2.1

Sampling and Spatial Resolutions

The sampling resolution of a DTS system is the smallest length increment a DTS system can sense (or sample) over the entire length of an optical fiber (**FIGURE 5**). The sampling resolution describes the DTS system's ability to convert the true continuous spatial distribution of temperature along a fiber into discrete measurements. The DTS system provides one averaged temperature measurement per spatial sample. The sampling resolution of a DTS system is determined by the sampling frequency of the data acquisition card, which is typically implemented with a field-programmable gate array and specialized high-speed analog to digital converters chip technology.



▶ **FIGURE 5**: The sampling resolution of a DTS system is the smallest length increment a DTS can sense.

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2.2.1

Sampling and Spatial Resolutions

Each temperature measurement provided by a DTS system is averaged over a specified length increment, known as the spatial sampling interval, so the sensor output response to a change in temperature along the fiber is somewhat blurred at the edges of the change.

The spatial resolution of a DTS system is determined by applying a step change in temperature between two adjacent lengths of fiber (10 m or more) and determining the distance needed to capture between 10% and 90% of the variation (**FIGURE 6**).

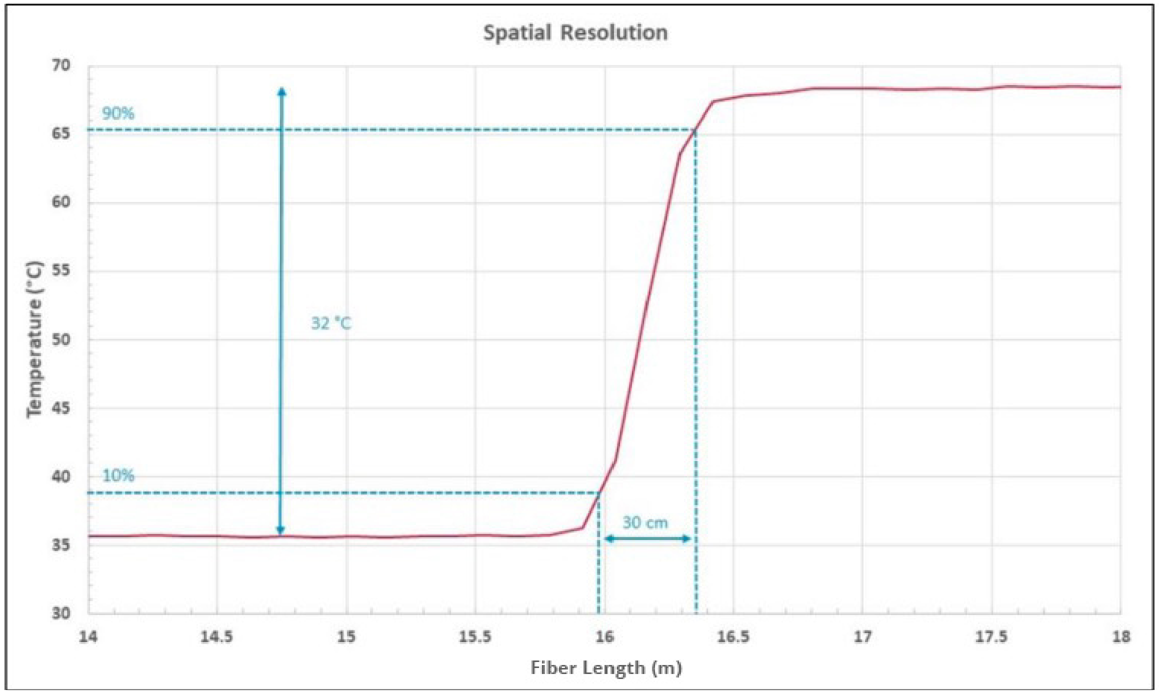
Typically, a temperature step of about 30°C is applied. The 10% 90% definition of spatial resolution is appropriate for determining the degree to which a transition can be reproduced in the sensor output.

It is important to note that different DTS manufacturers may apply different definitions. For example, defining the sampling resolution as the spatial resolution, varying the amplitude of the step change in temperature, and/or accounting for another percentage of detection (e.g., between 20% and 80%). Care should be taken when comparing DTS systems, with specific attention as to how spatial resolution is defined.

Although the spatial resolution and sampling resolution are related, they must not be confused with each other. The sampling resolution cannot be equal to the spatial resolution. The sampling rate must be more than twice the highest frequency component of a signal to properly capture the signal. Similarly, the spatial resolution cannot be smaller than the interval distance of two consecutive samples.

In general, the spatial resolution is slightly larger than two times the sampling resolution. Oversampling at much greater than one half the spatial resolution results in increased data volumes without significant additional information contained within the dataset.

▶ **FIGURE 6**: Spatial resolution test for the Silixa Ultima-S with sampling resolution of 0.125 m. The applied temperature step change is 30°C, to yield a spatial resolution value of 0.30 m.



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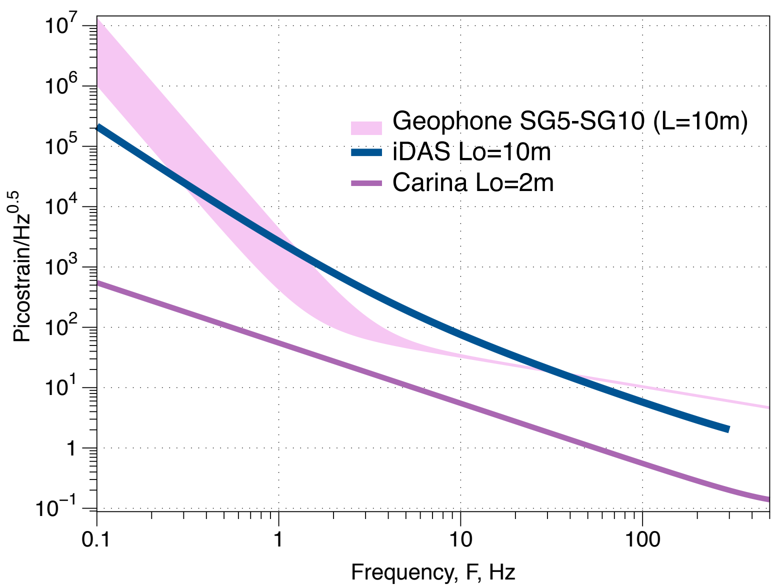
2.3 Distributed Acoustic Sensing (DAS)

DAS is an optoelectronic system that uses the Rayleigh backscattered light and principles of OTDR to demodulate dynamic strain events along the fiber cable.

By recording the returning signal against time, a measurement of the acoustic field all along the fiber can be determined. There are a wide range of DAS architectures, with the most advanced systems capable of measuring quantitative true acoustic signals (coherent in amplitude and phase) with low system noise over long ranges of tens of kilometers. The native data output is quantitative strain rate (dynamic strain). These systems can have a detection bandwidth from millihertz (mHz) to hundreds of kilohertz (kHz), depending on the temporal sampling rate, and can perform equally well with standard single mode and multimode fiber, without the introduction of external or additional apparatus. This feature makes it possible to access legacy fiber optic installations for new acoustic surveys, although new installations offer the ability to utilize specialty precision engineered sensing fiber for significantly improved measurement performance. As an example, see the case study on the Otway Project at the end of this document.

The importance of collecting the true acoustic signal–amplitude, frequency, and phase cannot be underestimated, as this opens the door to a wide range of array processing techniques that can be used to extract the maximum value from the data. For example, this capability uniquely allows DAS to be used to determine the speed of sound or seismic waves in the material surrounding the fiber optic sensing cable. This enables using the speed of sound for accurate time -lapse seismic surveys (White et al., 2019), or to monitor microseismic events with hypocenter localization capability (Richter et al., 2019). DAS has been used in many seismic acquisitions, encompassing vertical seismic profiling (VSP), in both flowing and non-flowing wells, passive seismic monitoring and surface seismic applications. The technology has been deployed in many industries, including unconventional hydrocarbon exploration (Richter et al., 2019) at CO_2 storage sites (Harris et al., 2016; White et al., 2019) in enhanced geothermal system wells (Mondanos and Coleman, 2019), and for infrastructure monitoring (Johansson et al., 2020).

The standard Silixa iDAS™ has a dynamic range of 120 dB (decibel) and a sampling frequency range from <1 mHz to >100 kHz, making it a highly versatile instrument. The iDAS responds to tiny strain events within the optical fiber which are induced by local wavefields. The system response to this strain is linear, making it possible to treat the iDAS data similarly to conventional sensor technologies such as geophones and accelerometers. This makes the iDAS a successful alternative system for seismic acquisition. The recent introduction of the Carina® system using specialty precision-engineered Constellation™ sensing fiber improves upon iDAS by offering a 20dB (100x) reduction in instrument noise floor and the ability to further extend measurement range (**FIGURE 7**).



▲ **FIGURE 7**: Noise floor comparison between geophones, iDAS, and Carina.

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2.4 Distributed Strain Sensing (DSS)

DSS instruments use Brillouin scattered light to determine the strain at each sampling point along an optical fiber.

The wavelengths of the Brillouin backscattered light differ from the forward propagating light and are named Stokes and anti-Stokes (**FIGURE 4**). The wavelength shift of the Stokes and anti-Stokes light are monitored by the DSS unit, and the spatial localization of the source of backscatter signal is determined using the principles of OTDR.

One challenge with DSS is that the wavelength shift is dependent on both the strain and temperature of the optical fiber; thus, crosstalk exists between these two physical measurands. If temperature fluctuations are expected, the thermal component of DSS response must be removed to isolate (nonthermal) strain. This is traditionally accomplished through dual-element cable designs that have (1) a fiber component sensitive to both temperature and strain, and (2) a fiber component engineered to be primarily sensitive to temperature with minimized physical strain transfer (to the fiber).

In practice, completely isolating strain from temperature signals is impractical, with temperature correction being more reliably carried out using temperature measured independently from a Raman DTS system, as described above. In summary, temperature compensation as well as strain coupling to the formation are important considerations for a DSS deployment.

Alternative measurement approaches for DSS that do not utilize Brillouin backscatter and, instead, rely on differential travel times between scatter centers using specialty precision-engineered sensing fiber are also available. DSS can be used for wellbore integrity monitoring, geomechanical deformation as the result of CCS operations, and cross-well plume front arrival detection.

3

Deployments of Fiber Optic Cable

3.1

Near-Surface

3.1.1

Cable Options

Fiber optic cables for near-surface installations (upper ~20 m) can be either fiber in metal tube (FIMT)-based or all-dielectric polymer constructions, with the latter being the most common.

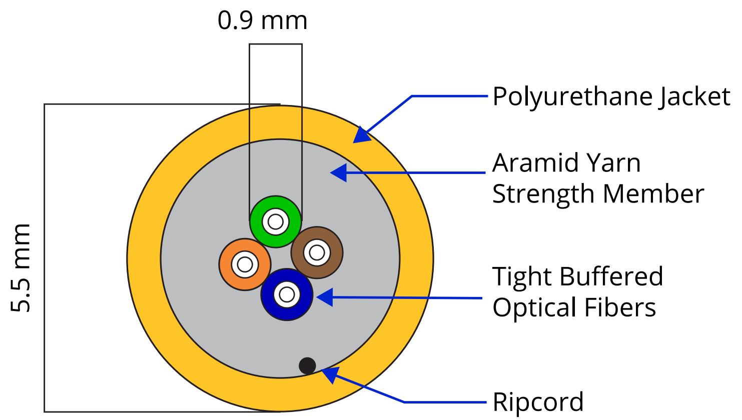
For DAS and DSS applications, signal coupling with the subsurface through the cable jacket and strength members to the optical fiber is an important consideration, with some cables offering efficient strain transfer to the optical fiber.

Near-surface deployments offer flexibility with the engineering design of the cable, as the cable is not subject to the harsh environments present downhole, including high temperatures, pressure corrosion risks, and constraints on deployment options. The types of materials, diameter, and fiber geometry within the cable are flexible to a greater degree which leads to numerous cable options that could be considered for deployment.

Although the surface environment is typically not as harsh as downhole, there are greater risks because of exposure to site activities. Tight buffered tactical (also referred to as military)-type cable has been widely installed for near-surface investigations due to its high level of durability and flexibility, leading to ease in deployments and relatively low risk of failure, good DAS/DSS signal sensitivity, and relatively low cost (**FIGURE 8**).

This cable type is also ideally suited to act as a link cable to facilitate connection from a mobile office to a cable installed downhole. Tactical cable is also well suited to DTS measurements, though extra attention needs to be paid to minimizing signal attenuation that can affect the accuracy of DTS measurements when compared with FIMT-based or loose tube designs.

Bend-insensitive fibers are recommended to be incorporated into tactical cable to help minimize the chances of both microbend- and macrobend-induced attenuation. The directional sensitivity of fiber (acting as a single-component measurement) for DAS measurements is another critical consideration when the cable will be used for surface seismic surveys. These helically wound



▲ **FIGURE 8**: Example four-fiber tactical cable construction.

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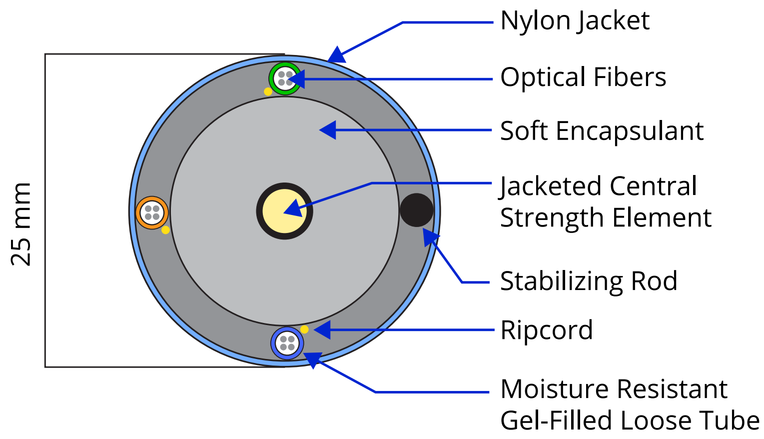
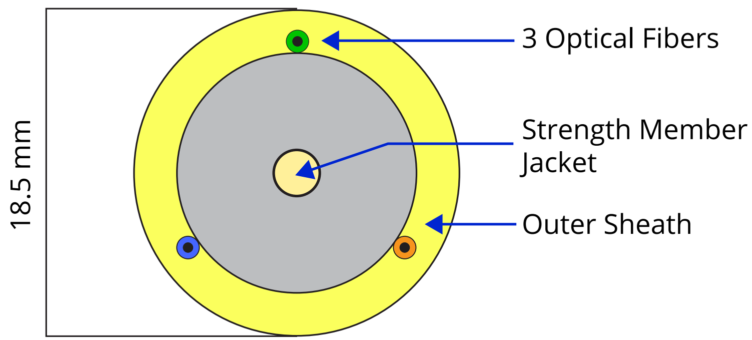
specialty cables (HWC) are available to optimize the measurement response in these situations (**FIGURES 9 AND 10**). In general, it is important to remember that the fiber optic cable is the deployed sensing element, and so both the cable type and deployment method control the quality of data recorded in a survey to a significant degree.



▲ **FIGURE 9**: Example HWC with fibers 30° off axis to provide increased sensitivity to broadside seismic waves.



▲ **FIGURE 10**: Example HWC with fibers off axes.

3.1.2 Installation Methods

Direct burial is the preferred installation method for near-surface installations to ensure good formation-to-fiber signal coupling for DAS and DSS data acquisition.

However, retrofits onto existing cabling installed for telecom purposes in conduits have been carried out with success (e.g., Ajo-Franklin et al 2019), but evaluation on a case-by-case basis is required.

For new installations, cable can be installed using trench-and-cover methods with a backhoe, trencher, or plow. The bottom of the trench should be prepared (compacted) and backfilled with a layer of fine material prior to cable placement. The cables should then be backfilled and compacted. The cable has length markings, and x- y- and z-coordinates should be surveyed with regular spacing and at locations of array inflection/bends. Induced taps, temperature, and strain can be used for cable-mapping purposes. Measurements of optical signal should be performed during placement of the cable as well as during backfilling of the trench to ensure integrity is maintained and excess optical attenuation is not induced because of physical damage or overcompaction.

As an alternative to trench-and-cover methods, cable can be installed with directional drilling techniques in access-restricted areas. Steel-armored cable is an option, depending on the installation method.

3.2 Downhole

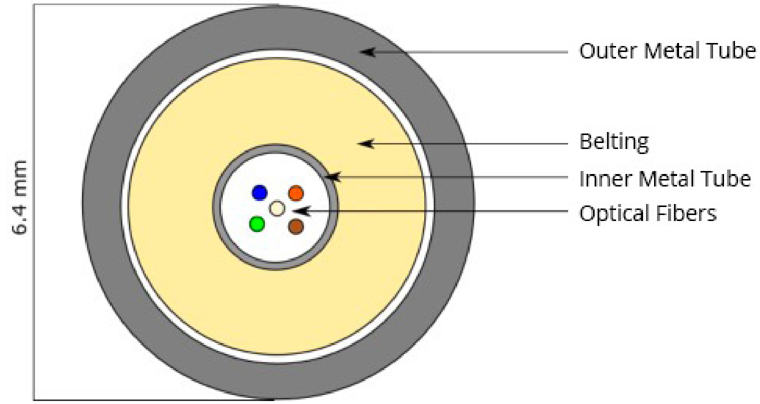
3.2.1 Cable Options

Downhole deployments require FIMT-based cable constructions to survive temperatures and pressures common with multikilometer-deep installations.

For permanent installations behind casing or attached to tubing, 1/4” (6.35mm OD) tube-in-tube designs (outer tube surrounding a small-diameter FIMT) are most common and generally manufactured with either SS316 or Incoloy A825 outer tube, with A825 preferred where corrosion is a concern. Outer tube wall thicknesses range from 0.028” to 0.049” depending on installation requirements, with 0.035” being the most common.

Belting is a layer of polymer between the FIMT and outer tube, which is recommended as it improves cable longevity, installation performance, and downhole termination reliability. (Figure 11) Polymer encapsulation can be extruded over the outer tube to provide an additional layer of protection if required. The downhole termination, commonly referred to as the bottomhole assembly, both seals the cable for fluid ingress and provides an environmentally sealed chamber for u-bend fiber splicing, which facilitates double-ended DTS measurements for improved accuracy and daisy-chaining multiple wells together for measurement with a single interrogator. Double-ended DTS configurations can improve accuracy and the ability to daily-chain wells together facilitates improved economics, as fewer distributed sensing interrogators are needed for acquisition. Smaller diameter (1/8” or 3.175mm OD) cables can be installed for temporary slickline deployments or FIMT-based wireline cables utilized for intervention wireline surveys.

For all downhole cables, there is wide variability in the number and type of optical fibers that can be integrated into cable construction. The precision-engineered Constellation™ sensing fiber enables DAS measurements with a 100x lower noise floor in comparison with standard single-mode fiber, which can be critical for microseismic and time-lapse VSP surveys. Although the mix of fiber types governs what type of measurements (DAS, DTS, DSS) can be made on a cable, cable design is a factor in measurement response. Cables optimized for DSS have been developed that



▲ **FIGURE 11**: 1/4” OD downhole fiber optic cable with belting.

prioritize efficient strain transfer through the cable construction to the optical fiber. The temperature rating of the cable is governed (along with other factors) by the coating type of the optical fibers. Common temperature ratings include 85°C, 150°C, and 300°C, with temperature rating being a significant factor controlling cable cost. Specialty high-temperature cables can be manufactured to survive at temperatures as high as 500°C. Hydrogen darkening (increasing optical attenuation with exposure to free hydrogen) can be a concern for long term installations, particularly at high temperatures. For peak temperatures less than 150°C, a hermetic carbon coating on the optical fibers provides an effective barrier to hydrogen ingression into the silica fiber; however, at temperatures above 150°C the efficacy of a carbon hermetic barrier is decreased. In this case, pure silica core fibers provide near immunity to hydrogen darkening by eliminating or substantially reducing the dopant concentration in the fiber core. Dopants such as germanium are generally used to control the refractive index profile of the fiber, but in harsh environments, a pure silica core may be preferred.

Casing – Permanent

Fiber optic cable is readily installed for permanent reservoir monitoring in both the injection and monitoring wells by clamping to casing and cementing in the borehole annulus during casing installation (Figure 12). Installing cable behind casing facilitates surveys and continuous monitoring without the need for well intervention to provide tool access. Thus monitoring can be carried out in the injection well without ceasing CO_2 injection, especially measurements of temperature and strain which are not affected by the injection process. Acoustic measurements could also be performed for flow allocation or active seismic surveys. Cable clamps/protectors are both used across couplings and midjoint to attach the cable to casing and prevent the concentration of stress on the cable at step changes in diameter at each coupling. Centralizers provide additional protection to the cable during installation while limiting variability in annular space for cementation. Protectors and centralizers are recommended to be used at every coupling location, with midjoint clamps used on each casing section.

▲ **FIGURE 12**: A) Permanent cable installation on casing at CO2CRC site, Otway, Australia, and B) an example of a fiber optic cable installed along a steel casing with a cross-coupling cable protection.

Tubing Deployed – Temporary/Semipermanent

Tubing deployments offer a means for semi-permanent installation in existing injection wells or for subsea installations where deployment behind casing may not be permissible. Cable is clamped to the tubing string during deployment and can be retrieved along with the tubing string at a later date. Cable coupling to the formation for DAS measurements has been demonstrated to be sufficient for most installations, although installation geometry should be considered. As an example, Pevzner et al. (2020) compare the data quality from different cable installation methods at the Otway CO_2 injection site in Australia.

Wireline and Slickline – Temporary

Although cable permanently deployed in casing or tubing provides the capability for intervention-free longterm monitoring, temporary deployments of optical fiber are common for monitoring in existing wells where fiber optic cable was not installed. In highly deviated or horizontal wells, the cable may be tractored or towed in place with a capillary injector unit. For both slickline and wireline interventions, cable coupling to the formation is an important consideration, as signal coupling to the cable can be relatively poor in vertical or near-vertical wellbores but has been demonstrated to be excellent for deviated (> 5 degrees) and horizontal wells.

4 Applications

Fiber optic cables can be used at all stages of a CCS project to build a temperature, strain, microseismic/seismic baseline through site characterization, baseline monitoring to monitor injection activities. Because of the long-life expectancy of the cables, the same fibers can be used to continue monitoring postinjection. Here we focus on monitoring for onshore CCS sites.

4.1 Baseline-Site Characterization

4.1.1 Surface Seismic Reflection Surveys

Surface seismic reflection surveys are the most comprehensive method to image CO_2 storage sites and characterize the geologic setting before injection commences. The surveys are used to produce a 2D or 3D image of geologic formations and image faults, which could be potential leakage pathways breaching the storage integrity of the site.

It is important for CCS sites that the caprock or sealing rock for the reservoir is continuous over the expected extent of the future CO_2 plume. Seismic surveys are the best available method to verify caprock continuity. Ideally, the site should have a thick caprock and secondary sealing units above the reservoir. Multiple applications for seismic reflection data are possible and are in varying stages of development.

Fiber optic cables can be trenched at the surface to provide a permanent, dense, seismic monitoring array covering up to tens of square kilometers. Because of the broadside insensitivity of linear cable to P-waves, it is beneficial to record P-waves on helically wound cable, which can be constructed to have good sensitivity to P-waves arriving from all angles. Recent studies have shown that HWC can be used to image a CO_2 reservoir at a depth of 2km (Correa et al., 2020).

DAS may be used with the complete range of seismic sources (vibroseis, dynamite, surface orbital vibrators [SOVs] and ambient noise). In addition to stacking shots, the dense spatial sampling of the technology provides the opportunity to stack data from neighboring channels to improve signal strength.

Note there are limitations to surface seismic surveys. They will not, for example, identify small, or near-vertical, or small offset faults.

4.1.2

VSP Surveys

VSPs use an active seismic source method using an array that is oriented vertically in a borehole.

VSPs measure downward and reflected energy. With vertical fiber orientation, the P-wave particle motion is close to in-line with the fiber, facilitating data collection with good signal-to-noise characteristics.

VSP surveys with fiber optics are among the best way to generate detailed structural information for CCS sites. They provide highly dense spatial sampling to produce well-resolved models in a relatively short timescale because data can be collected covering the full-length of the well with a single fiber. Surveys with geophones usually require intervention to move the geophone string up and down the well to achieve the desired resolution. This is typically achieved with the use of a rig, which increases the survey costs and inhibits any well activity for the duration of the survey. With the high-resolution structural information derived from DAS data, it is possible to generate a baseline image, produce 3D VSP results and assess the migration of a CO_2 plume through time within the geometry limits of VSP surveys.

With permanently installed fiber it is possible to efficiently take repeated measurements after baseline surveys to monitor changes long-term, including time-lapse plume imaging as discussed in the CO_2 Plume Mapping section.

4.1.3

Baseline Seismicity

To fully understand the effects of injection activities, it is essential to monitor a site for background seismicity. The location of background seismicity highlights active faults and, hence, enables a seismic risk assessment. Seismic monitoring can help identify active faults that are not observed in 3D seismic data. A baseline seismicity assessment is an important tool to enable an assessment of unexpected seismicity during CO_2 injection.

The risks posed by seismicity and monitoring solutions are discussed below in the Induced Seismicity Monitoring section.

4.1.4 Periodic Hydraulic Testing

Periodic hydraulic testing uses an applied periodic pressure signal in a source well, with the pressure response monitored in surrounding boreholes, to characterize the hydraulic properties of an aquifer or reservoir.

The amplitude decay and phase lag of the pressure signal measured in the monitoring well provide an indication of the hydraulic diffusivity of the reservoir between the source-receiver well pair. The applied periodic signal can be altered in frequency to give diffusivity estimates at a range of spatial scales, with low frequencies (millihertz) providing adequate radii of penetration suitable for field studies at the reservoir scale.

Traditionally, individual pressure sensors are deployed in each monitoring well, which provide a bulk estimate of diffusivity. Strings of pressure gauges can provide depth discrete data to resolve diffusivity to a finer degree. More recently, DAS has been proven to be a highly effective tool for conducting periodic hydraulic tests, because of its high sensitivity to dynamic strain, which allows monitoring of hydraulic signals of even lower amplitude than is possible with pressure gauges (Becker et al., 2017, and 2020). Modulated pressure in the reservoir is translated to strain because of hydromechanical fracture dilation and contraction and the poroelastic response. The periodic strain measured by DAS can then be related to pressure using a coupled hydromechanical model or known relationship between pressure and strain.

The complete borehole sensory coverage provided by DAS (thousands vs. traditionally one or a few sensors) provides the opportunity for advanced reservoir tomography. In addition, periodic hydraulic testing can be used to monitor the integrity of the caprock and boreholes, as detection of the applied periodic signal at shallower depths may indicate hydraulic connection. Applying this technique at multiple instances throughout the life of the reservoir provides a means of time-lapse hydraulic monitoring.

4.1.5

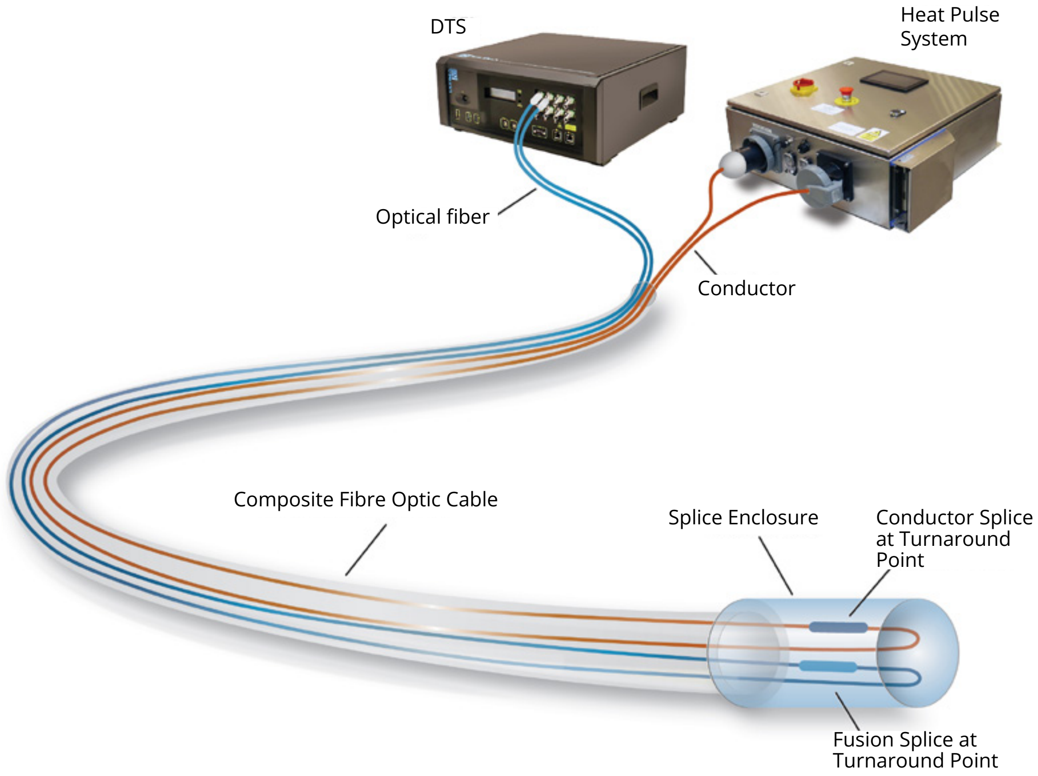
Apparent Thermal Conductivity

Thermal conductivity can be used to distinguish lithology units because of different mineralogy composition, providing to each rock type a characteristic bulk thermal conductivity and intervals with fluid flow.

When active fluid flow is occurring during an in situ thermal conductivity test, the bulk rock thermal conductivity values would be apparently enhanced because of increased heat dissipation caused by the fluid flow.

Hybrid fiber optic cables containing copper conductors and optical fibers provide the opportunity to heat the entire fiber optic cable length while maintaining the capability to monitor temperature variation over time.

A power controller, such as Silixa's heat pulse system (**FIGURE 13**), can be combined with a DTS unit to perform heat pulse tests to estimate in situ apparent thermal conductivity profiles that can be used to characterize lithology distribution and active fluid flow. Examples of this method applied in CCS projects include Freifeld et al. (2009) and Prevedel et al. (2014). Examples in shallow boreholes can be found in Coleman et al. (2015), Maldaner et al. (2019) and Munn et al. (2020).



▲ **FIGURE 13**: Example of an active DTS system setup using a DTS unit and heat pulse control unit with a composite cable containing both optical fibers and conductive wire.

4.2 Injection Optimization

4.2.1 Flow Profiling

Using DAS, measurements of acoustic activity can be employed to assess the flow of fluids in wells as a function of depth.

The flow of fluids from well casing to formation, or from formation to well casing, has a characteristic acoustic signature that is localized to the region of fluid flux. A qualitative estimate of flux can be used to assign fluxes at known depths as a proportion of total flow out of (in the case of fluid production) or into (in the case of fluid injection) the well. Where the necessary input data allow, these flux values can be calibrated in a quantitative profile of fluid flow along the depth of installed fiber.

Acoustic activity is calculated for the purpose of flow profiling by using spectral analysis of downhole DAS data, typically installed in vertical or deviated wellbores. For best results, fiber optic cable assemblies should have good coupling with the well casing or surrounding formation by being secured or grouted in the well: within the casing, between casing and pipe, or between casing and surrounding formation. High-frequency (> 8 kHz) acoustic data are transformed to the frequency domain with an FFT (fast Fourier transform) calculation at each sampling location along the optical fiber path within the depth region of interest. Examination of FFT amplitudes for a given application or deployment inform the appropriate frequency range attributable to acoustic activity resulting from fluid flux. RMS (root mean square), summation, or other means of aggregating FFT amplitudes are applied at each depth, resulting in a proxy for fluid flux. These accumulated amplitudes may then be qualitatively compared or calibrated to provide estimates of downhole fluid flux.

In the context of CCS, flow-profiling techniques can be used to document the apportionment of CO_2 fluid injection into the surrounding formation in cases where there are multiple injection depths. Such information can inform decision making regarding the efficiency of individual perforation clusters after the beginning of CO_2 injection and over time.

4.2.2 Flow Assurance

Where CO_2 capture is a temporally variant, commingled stream from emitters of diverse industries, the differing impurities, although small, will have a significant and dynamic impact on the CO_2 phase behavior. To fully understand and manage the CO_2 phase behavior in the wellbore, accurate and high-resolution temperature measurements will be important.

4.2.3 Injection Well Monitoring

DTS is a powerful tool for understanding CO_2 injectivity. There are some clear indicators of the lowest point of injection, which changes over time as a function of injection rate. The major CO_2 sink can be identified by a slow warmback response during shut-in. It should be noted that these changes are relatively small in temperature, supporting the case for a high-resolution instrument.

4.3 Wellbore Integrity

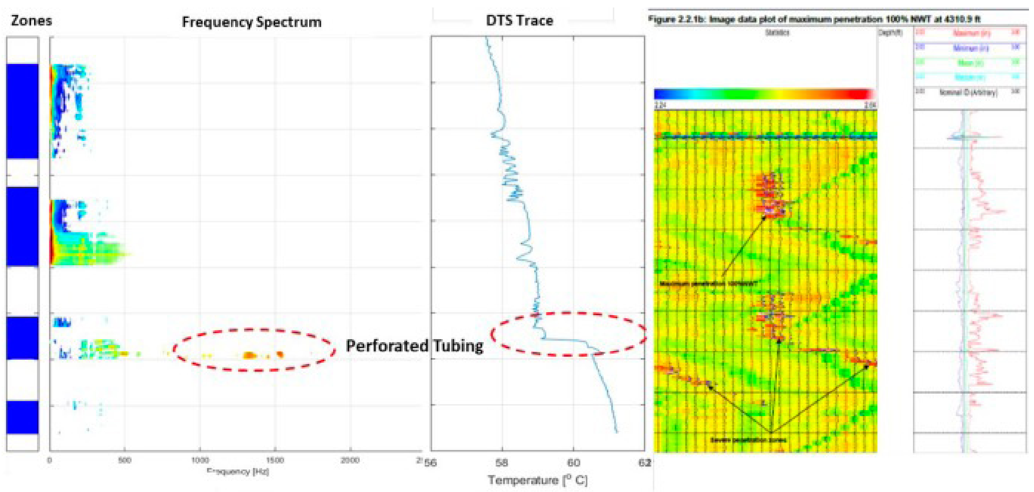
Continuous temperature data acquisition along CO_2 injector wells can provide important information about the wellbore integrity.

4.3.1 Temperature Monitoring

The temperature difference between the injected CO_2 and the reservoir temperature serves as a tracer to indicate locations of CO_2 leakage along the well.

The fiber optic distributed sensing system to detect CO_2 leakage consists of a fiber optic cable with multimode fibers cemented along the outside wall of a well casing. At the surface, the optical fibers are connected to a DTS unit, such as the Silixa ULTIMA™ DTS or XT-DTS™, that can be deployed in different operational environments to provide high-resolution temperature data.

Temperature data are continuously collected and an integrated system monitors variation of the actual temperature signals against the expected range. If readings occur outside of the expected range, an alarm is triggered, and a signal is sent to the operators to assess the data and take any required actions (FIGURE 14).



◄ **FIGURE 14**: Tubular failure identified by acoustic (left) and temperature (right) anomalies.

4.3.2 Acoustic Monitoring

A plan to continuously monitor fiber optic cable installed in a CO_2 injection well using DAS can be leveraged to notify operators of any damage to the wellbore along the entire depth of installed cable. This could include damage to plugs or valves, casing, grout, or surrounding formation (FIGURE 14).

Since the location of any such damage can be localized within a few meters, decision making is well informed of the potential severity of continued injection operation.

More intermittent acoustic monitoring can be carried out using periodic drive-by surveys to identify the locations and severity of potential CO_2 leaks. The flow of high-pressure fluids through well perforations (either intended or accidental) has a well-defined acoustic signature.

Acoustic data can be monitored for the onset and evolution of such leakage signals. The location of leakage is easily identifiable in the acoustic data, and the severity of leakage can be parameterized by the power distribution of the frequency spectrum.

4.4

CO_2 Plume Mapping

4.4.1

Seismic Imaging

Time-lapse seismic is a way of using a series of seismic images of a reservoir through time to monitor changes in a survey area.

It is possible to create seismic images through either multiple 3D surface or VSP surveys. By viewing time-lapse data, both the storage reservoir and the overburden can be monitored. Changes in the seismic response to a CO_2 plume can be monitored and assessed. This geophysical exploration method is especially critical for safety monitoring at CO_2 sequestration sites because it makes it possible to view the migration of CO_2 over time. Consistent and accurate monitoring is critical for risk management of CO_2 injection.

Fiber optic cables provide a permanent monitoring capability to allow imaging of a CO_2 plume. This permanent installation provides the means for repeated measurements in the same area over tens of years with lowered costs, without compromising on data sampling.

Monitoring surveys are repeated with sufficient temporal resolution to capture the plume evolution. Typically, surface sources such as vibroseis trucks are used in a VSP setting to image plume boundaries and saturation around injection and monitoring wells. However, high survey costs and an increased need for higher temporal resolution are driving the development of continuous reservoir monitoring techniques by means of installation of permanent surface sources. Recent examples of SOVs coupled with DAS in a VSP setting have provided comparable results to conventional time-lapse seismic with vibroseis and geophones (Correa et al., 2017, 2018; Freifeld et al., 2016). Such a combination allows for cost-effective surveys, on-demand source interrogation, a minimally invasive approach, and a massively improved temporal resolution compared to traditional methods, and it represents the next step toward an affordable and truly continuous reservoir monitoring.

Crosswell survey settings are less common because of the higher costs derived from well occupation and the limitations of borehole sources in terms of energy and reliability. However, such an approach can guarantee a higher spatial resolution resulting in the ability of accurately mapping even subtle changes in the injection plume boundaries for early detection and quantification of leakage pathways and secondary accumulation. To successfully implement a crosswell approach, development is required to produce more dependable, highly repeatable, and low-impact sources (e.g., borehole orbital vibrators).

4.4.2

CO_2 Plume Breakthrough

A faster CO_2 plume dispersion can happen through highly permeable layers or preferential flow paths such as rock formation contacts, geologic faults, and dissolution features, especially in reservoirs formed by carbonate rocks. These preferential flow paths are difficult to predict during the characterization phase because of its small dimensions and heterogeneous distribution, requiring high spatial resolution and continuous monitoring to detect them.

Fiber optic distributed sensing methods offers an advantage over traditional point sensors because of their high temporal and spatial (≤1 m) resolutions and spatial coverage of tens of kilometers. Continuous monitoring of acoustic, strain, and temperature provides an opportunity to detect potential early arrival of the CO_2 plume at a monitoring well equipped with a fiber optic cable.

4.5 Induced Seismicity Monitoring

Injection of CO_2 can induce seismicity via different mechanisms, and these events may pose a risk to CCS projects in different ways. Below is a summary of induced seismicity risks and the monitoring required to mitigate this risk.

4.5.1 Induced Seismicity

Induced seismicity in the form of felt earthquakes can occur due to an increase in stress on preexisting faults or because of lubrication of faults due to increases in pore pressure. These can be large magnitude seismic events and potentially damaging wellbores or surface infrastructure. Additionally, the reactivation of faults could result in leakage pathways for CO_2 and lead to potential migration of CO_2 and native fluids to the shallow subsurface.

The size and potential for this type of event depend on the specific geologic and structural history of the site. A thorough structural characterization of the site before injection can help identify potential seismicity risks. Surface or downhole DAS for seismic monitoring during CO_2 injection can also help mitigate this risk.

Often monitoring is required over a large area (km^2) at CCS sites because, over time, the CO_2 plume will occupy a significant volume and cause deformation over long distances. Large area coverage is possible with fiber optic cables. However, surface arrays are often further from the seismic source than borehole deployments; hence the signal is more attenuated.

Additionally, near-surface material is highly attenuating, and so surface deployments suffer from low signal-to-noise data. In this case smaller seismic events will not be detected. Surface cable deployments require helically wound fiber if P-waves are to be well detected.

Borehole monitoring for seismicity is discussed below in the context of microseismic monitoring because this is the most common application.

4.5.2

Microseismic Event Detection and Monitoring

Microseismic events are analogous to small earthquakes and generally have magnitudes (M)<0.

This type of seismic event occurs naturally but can also be induced by anthropogenic activities, particularly in scenarios where fluid/gas are injected into the subsurface. Microseismicity can occur on preexisting faults and fractures, but fractures may also be created by hydraulic fracturing in the injection process. CO_2 storage reservoirs are often chosen because they are thought to have high injectivity. Therefore, large volumes of fluid may be injected without exceeding the pressure required for hydraulic fracturing at the injection point or in the surrounding formation.

If this is the case, CO_2 storage projects are not expected to result in significant microseismicity. If microseismicity is detected, it could indicate the reactivation of a preexisting fracture network as described in Stork et al. (2015), which could trigger enhanced monitoring to ensure storage integrity.

The energy released by microseismicity is small, and it is necessary for monitoring equipment to be in close proximity (within hundreds of meters) to the events because the waves are quickly attenuated. Borehole monitoring is a good option because the array can be placed at or close to the injection depth. With multiple monitoring wells, precise event locations can be determined over the required area. Well-known seismic event locations aid the geomechanical interpretation of the effects of injection: an important aspect of verifying geological and geomechanical modeling of injection scenarios.

A microseismic array for CCS projects should cover a wide aperture (i.e., provide event detection over a range of directions and angles) because events may result from stress effects and pore pressure changes at significant distances from the injection point. DAS downhole monitoring provides coverage over the whole length of a borehole, while geophone arrays are often limited to a small number of instruments covering a specific depth interval.

Fiber optic cables can be deployed behind casing and cemented in place during well construction, providing a permanent monitoring array in a monitoring well, or even an injection well that can be interrogated continuously or periodically over tens of years.

Alternatively, a semipermanent installation can be made in a previously existing borehole by clamping the cable to the borehole tubing. A further possibility is deployment of a cable via wireline. However, to provide the best quality data, the cable should be well coupled to the borehole wall; therefore, unclamped wireline deployments in vertical wells are not recommended.

Highly sensitive instrumentation is required to detect microseismic events with expected ground motions on the order of nanometers. Therefore, it is important that sensors are well coupled to the ground or geologic formation and that the instrumentation noise is minimized to allow such small signals to be detected. Recent advances in DAS technology have produced fiber optic sensing systems with sensitivities equivalent to geophones.

In particular, the Carina® Sensing System provides data with a 20dB improvement over the highest performance single-mode fiber DAS systems, allowing the minimum detectable magnitude to be reduced by approximately one magnitude unit. The minimum detectable magnitude for a particular project is dependent on the source-cable distance, geologicl setting, and array geometry.

5

Deformation

CO_2 injection could lead to a significant surface heave because of pressure buildup in the reservoir and buildup of injected CO_2.

A successful field development program needs to take reservoir deformation into account to minimize risk to well integrity, casing failure, fault reactivation, surface infrastructure, and optimize storage.

The acoustic waveforms recorded by DAS are a measure of the strain rate applied to the fiber optic cable at any one point in time. By integrating continuously recorded strain rate data in the time domain, uniaxial cable relative strain can be measured.

Since linear fiber optic cable, interrogated by a DAS system, measures only normal strain rate in the direction of the axial dimension of the cable, the full strain tensor of the surrounding material or formation cannot be determined without additional information. Informed assumptions about the properties of the material to which the cable is coupled can leverage the uniaxial strain measurement toward an understanding of the rate and magnitude of formation deformation.

DAS-derived strain measurements, applied to CCS installations, can be used to model deformation in the reservoir formation. For example, monitoring strain along a cable installed in an observation well can show when, where, and to what degree the reservoir formation is deforming to accommodate CO_2 injection.

Strain and, therefore, deformation along the wellbore outside of the reservoir formation depth can indicate misallocation of injected CO_2 via damage to the injection well or poor cap formation integrity. Models of deformation near the surface can help with verification of compliance with local regulations applicable to CCS operations.

The relative strain method would be the most sensitive and potentially fastest to detect strain events; however, system interruptions (due to downtime or other measurements) will reset measurement of absolute change, which is why an absolute strain method is also important. A combination of these methods will be used to detect the strain and provide correlation for high degree of confidence.

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6

A Permanent Real-Time Monitoring System

6.1

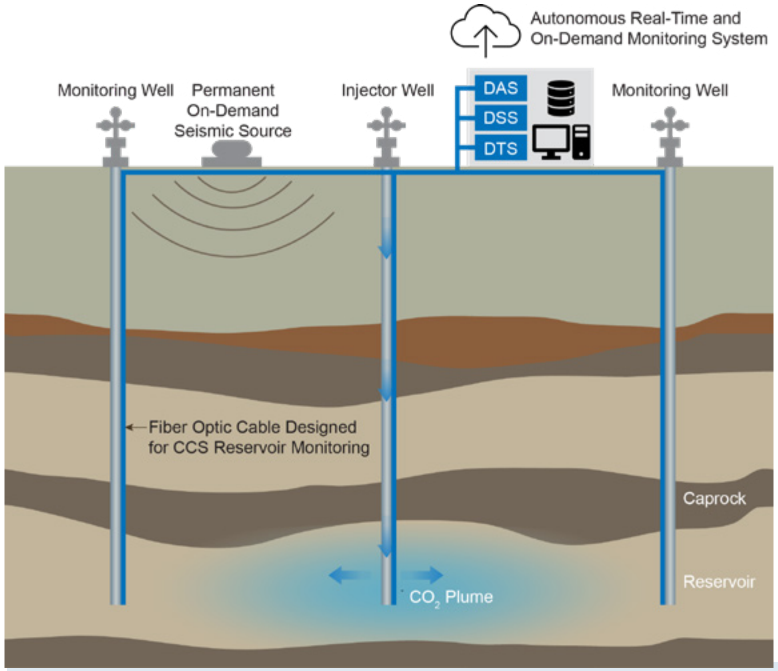
Onshore CCUS Monitoring

A permanent real-time monitoring system for CCS consists of an integrated system to facilitate continuous and cost-efficient CO_2 reservoir monitoring for risk mitigation and injection optimization.

In the injector well and monitoring wells, an online microseismic and wellbore integrity monitoring system is based on autonomous and continuous DTS, DAS, and DSS data acquisition with edge processing on a local server, with event data submission to a cloud storage system for further remote processing, interpretation, and verification (**FIGURE 15**). CO_2 plume evolution mapping is done based on on-demand, time-lapse VSP surveys. These surveys can be done remotely without expensive crew or equipment mobilization using permanently installed fiber optic cables, DAS units, and seismic sources such as the small footprint SOVs. (**FIGURE 15**).

The permanent monitoring system delivers enhanced quality data since the sensors and seismic sources are in the same location for all surveys, minimizing survey variability. Environmental impact is reduced, and cost-savings can be achieved by avoiding well intervention and mobilization of traditional seismic sources using vibe trucks. Critical for all operations is the repeatability and sensitivity of the measurements. Engineered fibers improve the signal-to-noise of DAS measurements while also enabling finer spatial resolution and extended measurement range. Extended range allows the optical fiber in multiple wells to be daisy-chained together to decrease overall system costs, and the improved noise performance enhances the ability to image CO_2 while improving survey efficiency through a reduction in the number of sweeps or shots at a given source point for seismic imaging. The same optical fiber cable is used for both temperature and strain profiling.

The first autonomous monitoring system was implemented in the CO2CRC Otway Project in Australia, and the preliminary results have been published by Isaenkov et al. (2021). The authors highlighted that the "monitoring system allows acquisition of seismic vintages every two days in an automated manner. The permanent installation requires no human effort on-site and thus drastically reduces the monitoring cost. Such a system can coexist within industrial or farm area as it produces a tolerable level of noise and operates only within the allowed time schedule (in the daytime).



▲ **FIGURE 15**: Silixa's integrated fiber optic distributed sensing monitoring system for carbon capture and storage projects.

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6.2

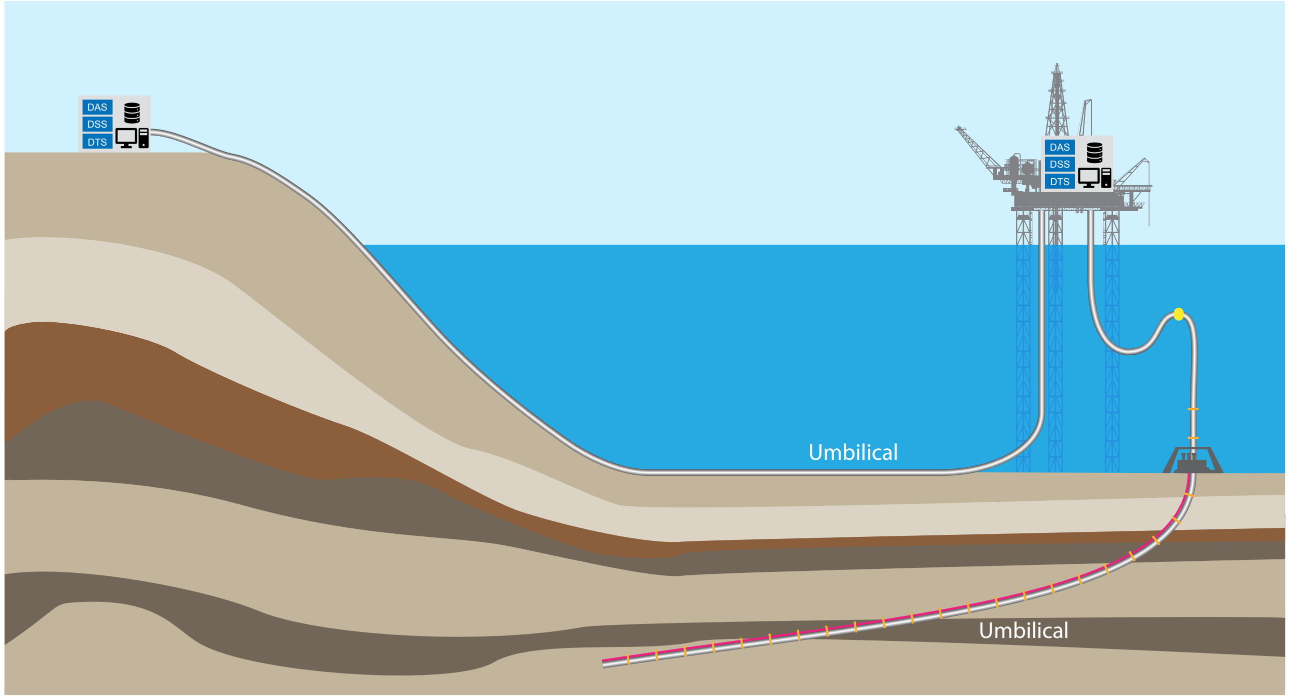
Offshore CCUS

In the context of subsea well monitoring, the huge increase in optical scattering from the Constellation fiber allows the interrogator to be placed much farther from the measurement location.

Deployments of the engineered fiber in offshore environments is unique in that it does not require any complex electronics to be placed on the seafloor. Acquisitions are performed from the topside facility utilizing existing fibers in the subsea umbilicals to carry the signal to the measurement region. Integration complexity and costs are, therefore, substantially reduced, and data management is simplified. The interrogator can address either the umbilical fiber or the fiber in the well often tens of kilometers away.

The long offset distance between the surface interrogator and subsea well does not compromise data quality. The engineered fiber optic cable and novel optical architectures allow the same high-quality data to be achieved as on existing land and platform systems. A typical subsea layout is shown in **FIGURE 16**.

The Carina® Subsea 4D interrogator can be located onshore, or on a remote platform, with the optical signal traveling through the umbilical to the well being monitored.



◄ **FIGURE 16**: Key components in a subsea well-monitoring system.

7

Case Studies

7.1

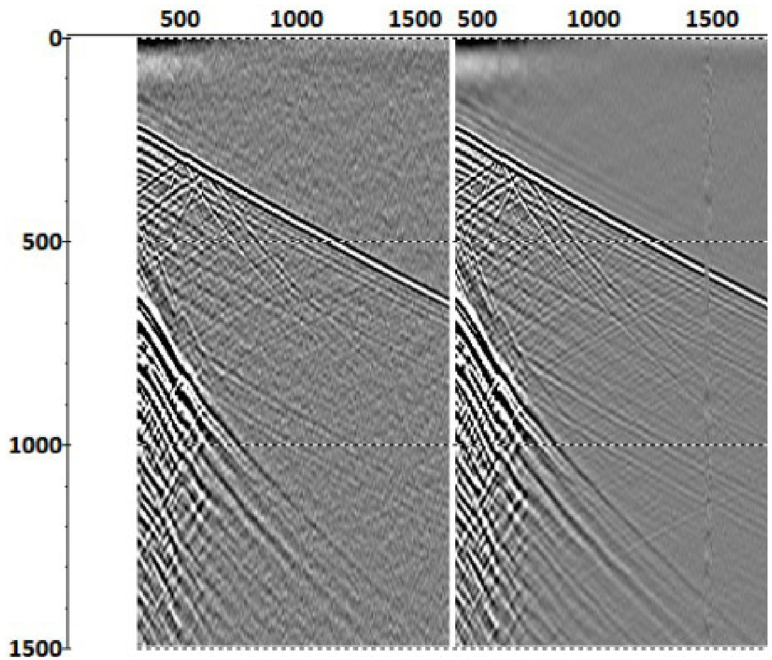
Otway, Victoria, Australia

An extensive, world-class monitoring program is ongoing at the CO2CRC Otway CO_2 storage test site in Victoria, Australia, where new capture and monitoring technologies are being benchmarked against conventional methods, such as traditional seismic surveys to monitor CCS sites.

Stage 3 of the project is now underway with the aim of developing continuous low-cost and low-environmental footprint solutions. This builds on the results from Stage 2 of the project which demonstrated safe injection of CO_2 into a saline formation and successful monitoring of the CO_2 plume evolution.

The inclusion of fiber optic monitoring at Otway began in Stage 1 with a cable deployed on borehole tubing. DTS measurements were used to monitor the geothermal profile and identify potential leaks. During Stage 2, CO2CRC injected 15,000 tons of CO_2 approximately 1,500 meters underground, and a further fiber optic cable was installed in one of the wells to benchmark DAS technology against seismic survey data recorded on geophones. (FIGURE 17). At the time of installation fiber optic DAS was a relatively new technology to be applied to seismic monitoring. However, it is now accepted that, with careful survey design, the latest DAS technology rivals geophones in data quality, and it provides many advantages, such as the potential for long-term repeatable measurements and dense spatial sampling without the need for well intervention. This was tested during Stage 2 at Otway with a cable cemented behind casing in a borehole.

Using 3D DAS VSP data recorded ata tubing installation at Otway, researchers from Curtin University and Lawrence Berkeley National Laboratory found the data were of good quality, and they were able to image geologic interfaces beyond the CO_2 injection depth. The use of Silixa's new Carina Sensing System technology highlighted a step change in the ability of DAS technology, with an improvement in noise levels of 20dB over previous systems. The advancement in technology enables far-offset surveys, facilitating monitoring over a wider area. These types of surveys are possible, even if cables are not cemented in place.



▲ **FIGURE 17**: VSP data recorded on iDAS (on the left) and Carina Sensing System (on the right). Data recorded using SOV source. Courtesy of CO2CRC.

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7.1

Otway, Victoria, Australia

Recently for Stage 3 of the Otway project, further fiber optic cables have been installed in five wells at the site. The technology will be tested not only for active seismic surveys but will also be applied to microseismic monitoring and passive seismic imaging using recordings of background noise.

In addition, the cables include optical fibers to monitor temperature profiles during injection and for early detection of potential leaks. Also, as part of Stage 3, surface cables with different specifications were installed at the site, and similar surveys will be recorded on these cables.

The environmental impact of monitoring is an important consideration for CO2CRC. Vibroseis trucks or dynamite are the most used sources for land seismic surveys. Both these techniques have a significant environmental impact requiring the transport of heavy equipment and personnel. Once on-site the sources can also be disruptive to local residents and/or farming activities because they are noisy and require access to extensive areas of land, up to a few square kilometers. The deployment of large numbers (1000s) of geophones also requires considerable effort in terms of personnel.

To reduce the environmental impact of seismic surveys CO2CRC, Curtin University and Lawrence Berkeley National Laboratory have been trialing the use of SOVs in combination with fiber optic sensors. SOVs are small seismic sources that are permanently deployed on the surface and can be operated remotely without disrupting local stakeholders. They have a small physical footprint and although they are much less energetic than a vibroseis source, the remote operation of the SOVs over a period of time can impart total energy, and, hence, signal quality, equivalent to the data obtained from a vibroseis survey. SOVs offer an alternative or complementary approach to traditional dynamite and vibroseis sources.

The success and environmental, safety, and cost benefits of the combined SOV operation with DAS recordings have resulted in the carrying forward of both these technologies to Stage 3.

It is envisioned that fiber optic monitoring will be available for multipurpose monitoring, and for use in continuous passive and time-lapse active seismic surveys, in-well temperature measurements, and deformation measurements. Detailed techno-economic studies will be performed as part of the Otway project, but it is estimated that overall a cost saving of up to 75 percent of monitoring costs over traditional monitoring technologies can be realized.

Correa et al. (2019) 3D vertical seismic profile acquired with distributed acoustic sensing on tubing installation: A case study from the CO2CRC Otway Project, Interpretation, doi: 10.1190/INT-2018-0086.1

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7.2

Aquistore, Saskatchewan, Canada

Aquistore, the world's first combined commercial power plant and CCS project, is located in Estevan, Saskatchewan, Canada.

It is managed by the Petroleum Technology Research Centre (PTRC). CO_2 is captured at the nearby SaskPower Boundary Dam coal-fired power plant. Following capture, a portion of the CO_2 is sold for enhanced oil recovery operations, and the remainder is transported by pipeline to the Aquistore site approximately 5km away. The CO_2 is injected into a deep reservoir via a 3000m injection well, where more than 275,000 tons of CO_2 has been permanently stored since April 2015.

Any CCS project requires a comprehensive testing and monitoring plan to ensure safe storage of the CO_2. Conventional active seismic methods provide snapshots of the site over time but are expensive. One safety concern and monitoring challenge is verifying that the CO_2 does not leak into the geologic layers above the storage reservoir with the use of seismic imaging methods. Any leakage negates the positive impact of mitigating climate change effects by preventing emission of the CO_2 to the atmosphere.

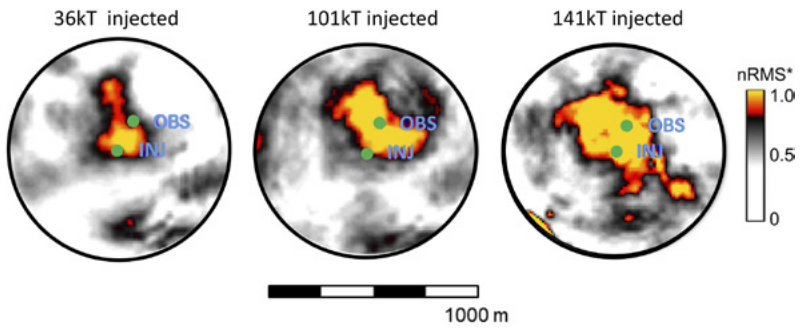
Another challenge is passive monitoring for any seismic events induced by the volume of CO_2 injected. These seismic events may indicate CO_2 leakage pathways or, if large enough, may damage infrastructure. An important part of measurement, monitoring and verification implementation is active seismic surveys to monitor and verify the behavior of the CO_2 underground and track the extent of the CO_2 plume.

Distributed sensing offers a viable alternative to geophone arrays for the acquisition of seismic data. It reduces monitoring costs and provides spatially and temporally continuous data. A fiber optic cable is permanently deployed in a monitoring well at the Aquistore site. This supplies a long-term and on-demand monitoring solution.

The benefits and quality of fiber optic DAS are proven for seismic acquisition, particularly for VSP surveys. DAS provides the capability to conduct repeat time-lapse surveys without intervention in the monitoring well, providing a cost-effective solution.

The data obtained from DAS are well suited to facilitating the detection of changes in seismic response due to the presence of CO_2 and the fiber can also be used to detect any seismic events at the site. With minimal environmental impact, Silixa's iDAS provides a long-term, on-demand, and cost-effective seismic monitoring solution for safe CO_2 storage at Aquistore and for CCS in general.

iDAS units have been used at Aquistore since 2013 to provide baseline and monitoring data via VSP surveys, with the most recent being in January 2020. These data have been used to image the CO_2 storage reservoir and track the extent of the CO_2 plume and verify caprock integrity. Significant leakage of CO_2 from the storage reservoir would be observable in the seismic response recorded by an iDAS interrogator.



3D DAS VSP INJ = Injection Well OBS = Observation Well

▲ **FIGURE 18**: Extent of CO_2 plume (bright colors) monitored over time with 3D VSP surveys recorded on a fiber optic cable and Silixa's iDAS unit. Monitoring surveys were conducted after 36kT, 102kT and 141kT of CO_2 were injected (courtesy of Don White, Geological Survey, Canada).

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7.3

Chester 16, Illinois, USA

The study was conducted under the U.S. Department of Energy National Energy Technology Laboratory's Regional Carbon Sequestration Program.

The Midwest Regional Carbon Sequestration Partnership is a multiyear research program to identify, test, and develop the best approach for carbon dioxide utilization and storage under the leadership of Battelle with partnership from Core Energy, LLC.

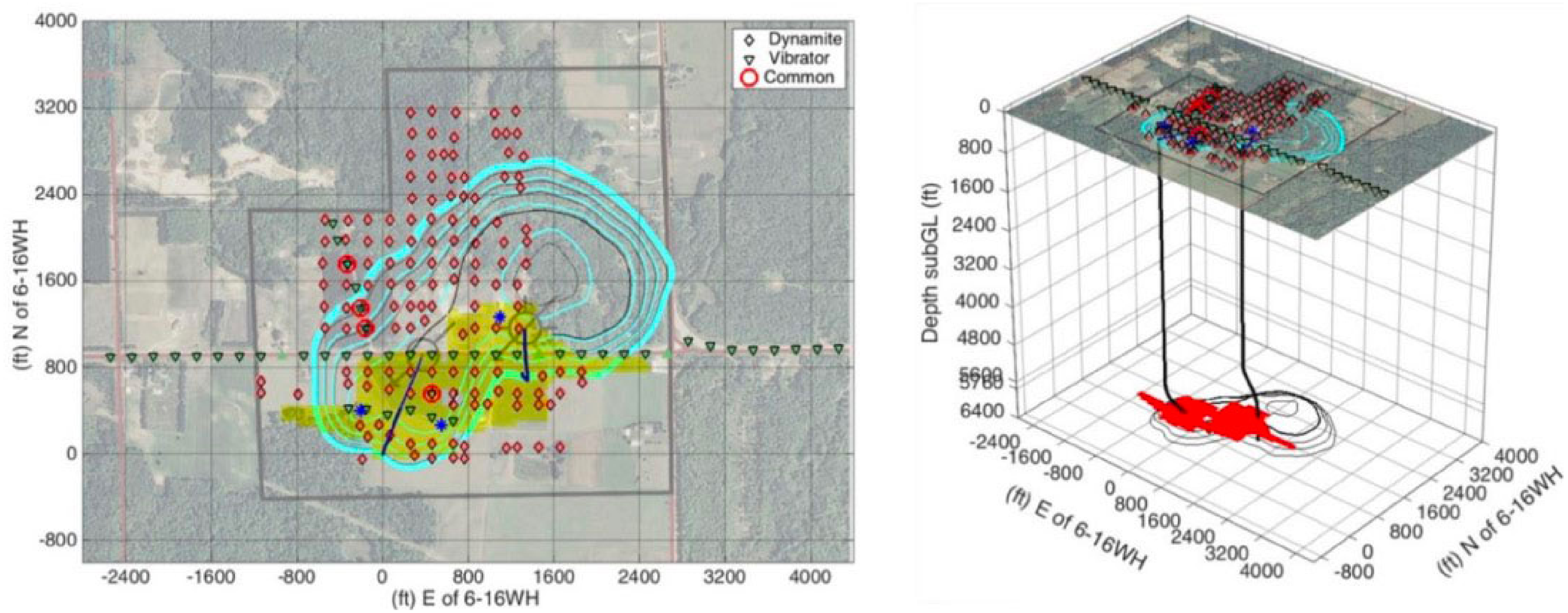
Part of the program is to map the injected CO_2 plume into carbonate reservoirs, and DAS time-lapse vertical seismic profiling was evaluated at Chester-16 pinnacle reef (**FIGURE 19A**).

Two new wells were drilled in late 2016/early 2017 with fiber optic cable installed outside casing to facilitate distributed sensing measurements (**FIGURE 19B**). Injection tubing was deployed in 6-16 and used to inject CO_2 into the reservoir, while a second well, 8-16, a future production well, was used to monitor the reservoir. A 3D DAS VSP survey was designed to illuminate the south part of the reef in an area between the two new wells. Because of access restriction, a combination of vibroseis and dynamite sources was used.

The operator carried out the first (baseline) 3D survey in 2017 prior to commencing injection of CO_2 into the reservoir, when reservoir pressure was low (approximately 700 psi). The second (repeat) 3D survey was acquired 16 months later in 2018 after 86,000 tons of CO_2 had been injected, raising the reservoir pressure to approximately 1500 psi.

4D VSP processing of the baseline and repeat surveys was aimed to determine the time-lapse effect of injected CO_2 on the seismic response. Two surveys were processed in parallel using the same workflow and parameters. The dynamite source data were processed separately from vibroseis source data.

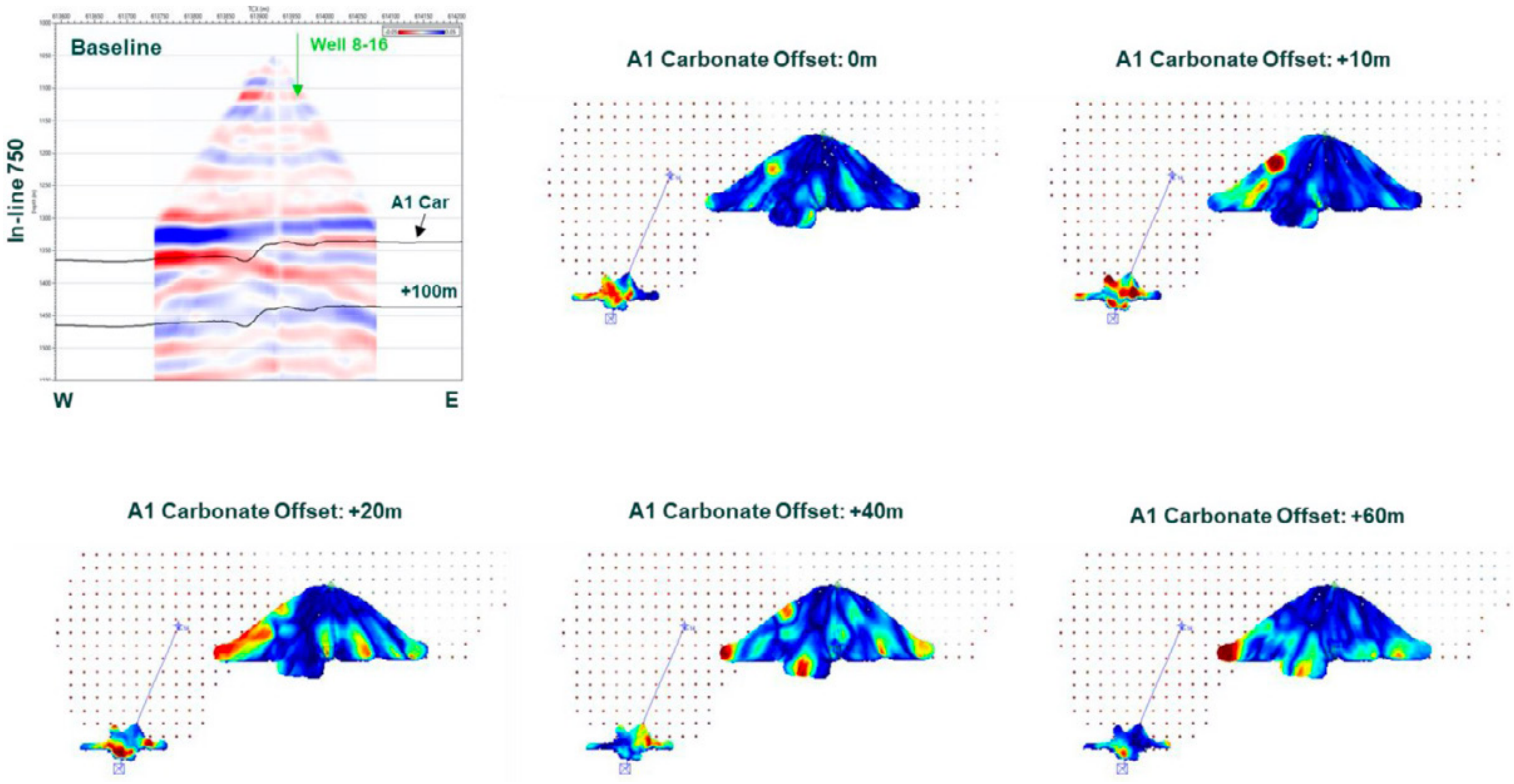
▼ **FIGURE 19**: Seismic sources geometry design in (A) plan view, and (B) cross-sectional view.



The quality of the data recorded using the vibroseis source was significantly better than that from the dynamite source, the refore the imaging was focused on the vibroseis data, as was the time-lapse analysis. The 3D velocity model used for VSP processing was constructed using the well acoustic logs and the well 8-16 ZVSP data. The recorded DAS time-lapse response was compared with several synthetic models. These models were built based on results from lab tests conducted on reservoir cores.

The 4D time-lapse analysis shows differences between the monitor and baseline surveys. Although part of the difference was attributed to noisier baseline-survey data, greater differences were present in the volume close to the injection well perforations which is considered to be caused by CO_2 injection. The importance of cementing the annulus across the entire depth range was highlighted, as data from part of the DAS array in 6-16 (the injector) were unusable because of excess injection noise from uncemented cable which limited the imaged volume around the well.

▼ **FIGURE 20**: (A) Difference amplitude RMS with the center of the analysis window at (B) the A1 Carbonate 3D surface and at (C) 10 m, (D) 20 m, (E) 40 m, and (F) 60 m below the A1 Carbonate 3D surface.



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How to cite this document

Silixa, **Carbon Capture and Storage Monitoring with distributed fiber optic sensing**, (March, 2022)

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