DigiMon Deliverable 2.3:

TRA of DigiMon components

Digital monitoring of CO_2 storage projects

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- LLC Lawrence Livermore National Security
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Glossary

Abbreviation	Description
ANI	Ambient Noise Interferometry
CCS	Carbon Capture and Storage
DAS	Distributed Acoustic Sensing
DCS	Distributed Chemical Sensing
DPS	Distributed Pressure Sensing
DSS	Distributed Strain Sensing
DTS	Distributed Temperature Sensing
CP	concrete platform
CTE	Critical Technology Element / DigiMon components
EOR	Enhanced Oil Recovery
OBS	Ocean Bottom Seismometer
SEL	Societal Embeddedness Level
TRA	Technology Readiness Assessment
TRL	Technology Readiness Level
VSP	Vertical Seismic Profile

Summary

The DigiMon project aims to develop an affordable, flexible, societally embedded and smart monitoring system for industrial scale subsurface CO_2 storage. For this purpose, the DigiMon system is to combine various types of measurements in integrated workflows.

In this report, we describe the process of conducting the Technology Readiness Assessment (TRA) of various measurement techniques. We report on the identification, description and assessment of these measurement techniques as Critical Technology Elements (CTEs) being part of the DigiMon system.

The DigiMon system needs to be capable of detecting and monitoring various aspects of a CO_2 storage complex. For our purpose we define this capability as being able to detect CO_2 migration within the storage site and, if it should happen, out of the storage complex. The system should also be able to detect any other significant irregularities, like migration through faults or the reactivation of faults potentially leading to undesired CO_2 migration out of the storage complex. A combination of individual measurement techniques including direct and indirect measurements will be part of the DigiMon system.

Numerous measurement techniques (CTEs) were identified and selected according to the following criteria:

- Suitable for applications offshore
- Suitable for large-scale CO_2 storage sites
- Suitable for application in near future (relative high TRL)
- Relevant for application in the near future (lower TRL)
- Affordability
- Subject experts available within the DigiMon consortium

With the ambition to develop a low-cost, early-warning monitoring system, the emphasis within the DigiMon project is on cost-efficient methods. Towards this end distributed sensing systems are of particular interest. Hence, where feasible, this TRA analysis includes an assessment both of the conventional measurement technique and of the distributed sensing alternative for each of the identified applications.

All CTEs have been systematically described following a structure and questions proposed by the Technology Readiness Assessment Guide of the U.S. Department of Energy. The goal being; to supply a uniform in-depth description and analysis of the selected CTEs.

The next table presents an overview of the selected CTEs is given. The list of CTEs is certainly not complete when considering the significant amount of measurements techniques capable of monitoring certain aspects of CO_2 storage sites. We examined and reported on what we regard currently as the most relevant CTEs for developing the low-cost, early-warning, offshore CCS monitoring system in DigiMon, in terms of technologies for field measurements relevant for application in the near future.

CTE (Critical Technology Elements) and TRL (Technology Readiness Level) overview.

Application	Class	CTE	TRL	Note
Surface and seabed reflection methods	Seismic reflection surveys	Conventional hydrophone of in case of OBN multi-component sensors	9	Mature technology
		DAS	5-6	Recent experiments show good potential
Borehole seismic methods	VSP	Conventional VSP	9	Mature technology
		DAS-VSP	8	Good results only used onshore sofar
	Crosshole tomography	Conventional sensors	5-6	In development and testing phase
Passive seismic methods	Microseismics	Geophone/hydrophones	9	Mature technology
		DAS	7-8	Operational but not applied
	Ambient Noise Interferometry	Geophone/hydrophones	4-5	
		DAS	4-5	
Microgravity	Microgravity at the seafloor	Point-based, mobile, microgravity sensors	9	Mature technology
Seafloor deformation	Measurements at the seafloor	Pressure sensors	9	Mature technology
		Tiltmeters	4	Good results, only used for other applications sofar
		DSS	4-5	Good results, only used for other applications sofar
Downhole Pressure sensing	Measurements in well	Conventional pressure sensors	8-9	Commercially available but lack long term use in CCS
		DPS	5-6	
Temperature sensing		DTS	9	Mature technology
Chemical sensing		Conventional sensors	9	Mature technology
		DCS	3	

For large-scale, industrial CCS operations, monitoring plans and their related activities are expected to be designed around risks. Typically CTEs with a high TRL score are most likely to become part of the monitoring plan. Such as seismic methods, mainly making use of conventional sensors, microgravity, DTS, etc. But also CTEs which are not yet at TRL 8 or 9 might be included, e.g. as a supporting technology to a mature CTE or to facilitate further development of the technology if results in other applications are promising.

During the design of an optimized monitor plan there is the possibility to combine monitoring data from various CTEs in inversion workflows. A workflow making use of data from multiple CTEs could outperform the capability of a single CTE by providing independent measurements of the same processes or illuminating multiple processes simultaneously. A TRA of various types of combinations of data streams and workflows is not covered in this report. However, this report will serve as a valuable tool in the continued work within DigiMon for integrating the different CTEs into the overall DigiMon monitoring system.

Sensitivity studies and uncertainty quantification of CTEs and the inversion of their data streams are underway as part of tasks 2.4 and 2.6, where data from field experiments and synthetic data of the Smeahea site is extensively used. For the system integration work, the (inversion) results will be analyzed with dedicated uncertainty quantification of the separate system components and when used in combination, considering information obtained from WP1 (D1.11), this TRA (task 2.3) and the SEL analyses (WP 3).

Maturation of individual CTEs covered in this TRA is, within DigiMon, obtained through the development in instrumentation, software and processing techniques. Through these efforts, the applicability of the technologies is sought to be improved either by enhancing the accuracy and sensitivity of the methods or implementing measures to improve the operational efficiency and reduce acquisition costs. The outcome of the work on the individual system components is included in this TRA. A dedicated summary of the specific developments will be provided in report D1.11 - Project report on WP1 outcomes relevant to other WPs.

1 Introduction

A Technology Readiness Assessment (TRA) is a formal, metrics-based process and accompanying report that assesses the maturity of critical hardware and/or software technologies referred to as the Critical Technology Elements (CTE) to be used in a system. Deliverable D2.3 of the ACT DigiMon project has become a report which describes the TRA of the measurement techniques for the DigiMon system.

Within the ACT DigiMon project, the TRAs goal is to describe technology maturity. In doing so it aids the structured development of the overall DigiMon system. The approach assesses the technologies maturity through the assignment of a Technology Readiness Level (TRL) which describes its development level, with TRL=1 representing basic principles observed and TRL=9 corresponding to an actual proven system.

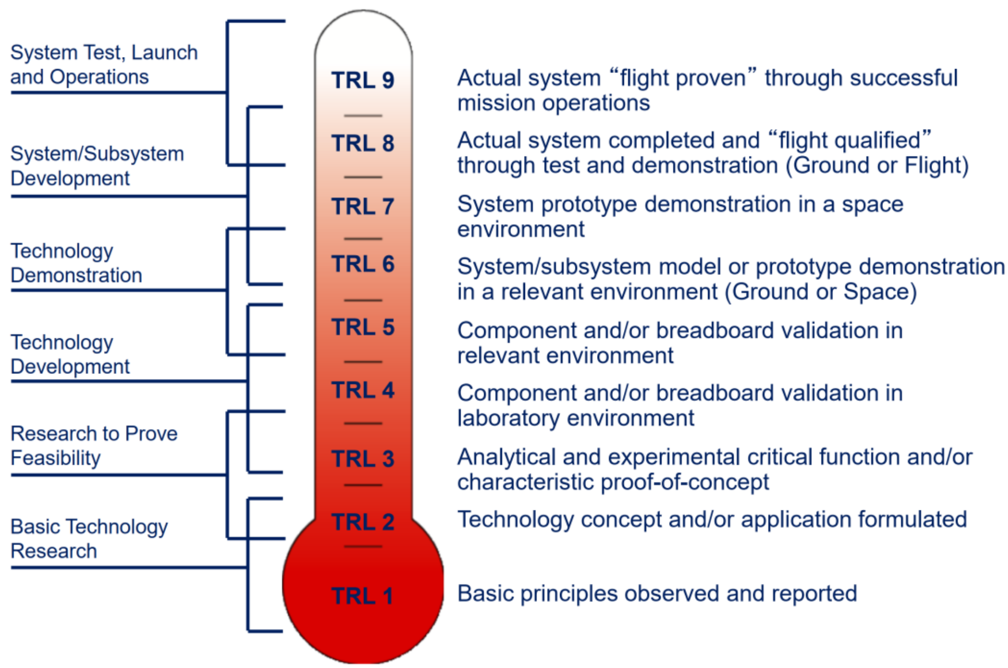

Figure 1. The TRA "thermometer" chart (ref. The NASA Systems Engineering Handbook, Appendix G, Technology Assessment/Insertion).

1.1 Uses of TRL and TRA

The need for TRLs and TRAs are both common and widely accepted to characterize technology maturity. Originally developed within NASA, it is now considered of great value having a common frame of reference for technology maturity characterization. The common nine-level TRL scale like displayed in Figure 1 is currently considered an adequate mechanism for characterizing technology maturity. The TRL scale is used almost universally by programs and projects for technology characterization. This is particularly true for low to mid-TRL technology development.

There are more interpretations of the TRL definitions, which could lead to confusion and inconsistency in applications. In a general sense we keep to the definition as set by NASA. TRLs are based on a scale from 1 to 9, with 1 being the least and 9 being the most mature technology level (Figure 1), but for our field of development we use a more suitable describtion of the nine-level TRL scale, as presented by the DOE (Table 1). The use of TRLs enables consistent, uniform and discussions of technical maturity across different types of technology.

Relative Level of Technology Development	Technology Readiness Level	TRL Definition	Description
System Operations	TRL 9	Actual system operated over the full range of expected conditions.	Actual operation of the technology in its final form, under the full range of operating conditions. Examples include using the actual system with the full range of wastes.
System Commissioning	TRL8	Actual system completed and qualified through test and demonstration.	Technology has been proven to work in its final form and under expected conditions. In almost all cases, this TRL represents the end of true system development. Examples include developmental testing and evaluation of the system with real waste in hot commissioning.
	TRL 7	Full-scale, similar (prototypical) system demonstrated in a relevant environment.	Prototype full scale system. Represents a major step up from TRL 6, requiring demonstration of an actual system prototype in a relevant environment. Examples include testing the prototype in the field with a range of simulants and/or real waste and cold commissioning.
Technology Demonstration	TRL 6	Engineering/pilot-scale, similar (prototypical) system validation in a relevant environment.	Representative engineering scale model or prototype system, which is well beyond the lab scale tested for TRL 5, is tested in a relevant environment. Represents a major step up in a technology's demonstrated readiness. Examples include testing a prototype with real waste and a range of simulants.
Technology Development	TRL 5	Laboratory scale, similar system validation in relevant environment	The basic technological components are integrated so that the system configuration is similar to (matches) the final application in almost all respects. Examples include testing a high-fidelity system in a simulated environment and/or with a range of real waste and simulants.
	TRL 4	Component and/or system validation in laboratory environment	Basic technological components are integrated to establish that the pieces will work together. This is relatively "low fidelity" compared with the eventual system. Examples include integration of "ad hoc" hardware in a laboratory and testing with a range of simulants.
Research to Prove Feasibility	TRL 3	Analytical and experimental critical function and/or characteristic proof of concept	Active research and development is initiated. This includes analytical studies and laboratory scale studies to physically validate the analytical predictions of separate elements of the technology. Examples include components that are not yet integrated or representative. Components may be tested with simulants.
	TRL 2	Technology concept and/or application formulated	Invention begins. Once basic principles are observed, practical applications can be invented. Applications are speculative, and there may be no proof or detailed analysis to support the assumptions. Examples are still limited to analytic studies.
Basic Technology Research	TRL 1	Basic principles observed and reported	Lowest level of technology readiness. Scientific research begins to be translated into applied research and development (R&D). Examples might include paper studies of a technology's basic properties.

Table 1. DOE Technology Readiness Level Scale (DOE, 2013).

1.2 This report

A TRA is a systematic process to develop the appropriate level of understanding (technical and risk) required for successful technology (e.g. DAS-VSP) insertion into a system under development (e.g. the DigiMon system). There are numerous reasons and benefits from performing TRAs, including reducing technology development uncertainty, providing a better understanding of project cost and schedule risk, facilitating infusion of technologies into systems, and improving technology investment decision-making.

TRLs are a method of estimating the technology maturity of CTEs. They are determined during a TRA that examines a system's concepts, technology requirements, and demonstrated technology capabilities.

This TRA report describes the process used to conduct the TRA and a comprehensive explanation of the assessed TRL for each CTE. The TRA provides:

- Identification of CTEs for monitoring carbon capture and storage projects using a conceptual (baseline) design of the DigiMon system.
- Objective scoring of the level of technology maturity for each CTE.
- A report (this document) documenting the findings of the assessment.

1.3 TRA Team

Table 2. Team to have worked on the TRA.

Organizations (alphabetical order)	**Representative**	**Relevant fields of expertise**
TNO	Vincent Vandeweijer	Various geophysical methods
TNO	Thibault Candela	Ground motion and Geomechanics
MonViro	Martha Lien	4D gravity and seafloor deformation monitoring
LLNL	Robert Mellors	Various seismic and geophysical methods
LLNL	Tiziana Bond	Chemical sensing
Geotomographie	Uta Koedel	Various seismic and geophysical methods, acquisition, and processing
University of Bristol	Antony Butcher	Microseismics and other seismic methods
University of Bristol	Wen Zhou	Various seismic methods.
University of Oxford	Mike Kendall	Various seismic and geophysical methods
Silixa Ltd	Anna Stork	Distributed temperature sensing and other geophysical methods.

2 Approach

The TRA scores the *current* readiness level of selected CTEs, using the defined TRLs and can be used as a tool for assessing program risk and the adequacy of technology maturation planning. The TRA provides a comprehensive review, using a program Work Breakdown Structure (WBS) as an outline, of the DigiMon system. In our case, this review, using a conceptual design, identified program CTEs related to *field measurements* and the TRA provides an objective scoring of the level of technological maturity for each CTE by experts.

Within DigiMon we choose to follow the procedure outlined below:

1. Identification of TRA participants, including allocating experts to the appropriate subject (Section 1.3)
2. Identification of CTEs and the definition of the terms for the assessment (e.g., operating environment and expected system applications) (Chapter 2)
3. Assessment of the TRLs (Chapter 3)
4. Review of TRLs (Chapter 4)

2.1 Identification of critical technology elements (CTEs)

The DigiMon project aims to develop an affordable, flexible, societally embedded and smart Digital Monitoring early-warning system. This system is to be used for monitoring any CO_2 storage reservoir and subsurface barrier system receiving CO_2 from fossil fuel power plants, oil refineries, process plants or other industries.

For this purpose, the DigiMon system, as graphically illustrated in Figure 2, is to combine various types of measurements in integrated workflows. The types of measurements vary from distributed (fibre-optic) sensors to (more conventional) point sensors.

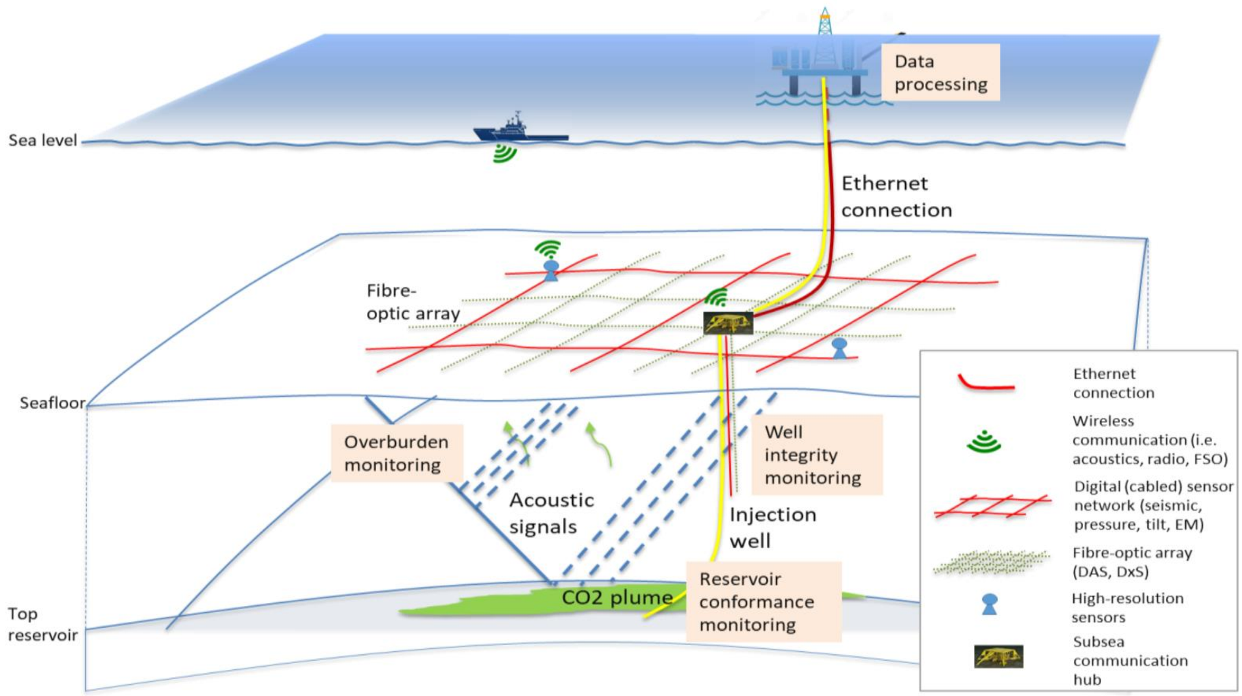

Figure 2. Illustration of the DigiMon system

In this TRA, we examined an extensive list of measurement techniques relevant to the DigiMon system. The examined measurement techniques were selected according to the following criteria:

- Suitable for applications offshore
- Suitable for large-scale CO_2 storage sites
- Suitable for application in near future (relative high TRL)
- Probably relevant for application in the future (low TRL)
- Affordability
- Subject experts available within the DigiMon consortium

The measurement techniques in this TRA cover technology which are expected to provide information during the different stages of the storage period from injection to long-term containment. We specifically focused on the inclusion of relatively new but promising various distributed technologies.

The main measurement technologies as assessed through experience on the existing offshore CCS sites are extensible covered in Anne-Kari Furre et al., 20 years of monitoring CO_2-injection at Sleipner, Energy Procedia 114, 3916 – 3926, 2017. Note, however, that the list of CTEs is certainly never complete when considering the significant number of measurements possibly capable of monitoring CO_2 storage sites. For technologies not covered in this TRA, we refer to the appropriate publications for an assessment.

The selected measurement techniques and CTEs reported on in this TRA are listed in Table 3.

Table 3. Selected CTEs.

Application	Class	CTE
Surface and seabed reflection methods	Seismic reflection surveys	Conventional hydrophone or in case of OBN multi component sensors
		Distributed acoustic sensors (DAS)
Borehole seismic methods	VSP	Conventional VSP
		DAS-VSP
	Crosshole tomography	Conventional sensors
Passive seismic methods	Microseismics	Geophone/hydrophones
		DAS
	Ambient Noise Interferometry	Geophone/hydrophones
		DAS
Microgravity	Microgravity at the seafloor	Point-based, mobile, microgravity sensors
Seafloor deformation	Measurements at the seafloor	Conventional point pressure sensors
		Tiltmeters
		Distributed strain sensor (DSS)
Downhole Pressure sensing	Measurements in well	Conventional pressure sensors
		Distributed Pressure Sensors (DPS)
Temperature sensing		Distributed Temperature Sensor (DTS)
Chemical sensing		Conventional Sensors
		Distributed Chemical Sensor (DCS)

2.2 Operating environment and system requirements

The TRL assessments are conducted against a specific set of requirements. A CTE can be at a different TRL depending on the requirements. For instance, a technology that has been demonstrated in offshore oil production, and is hence at TRL 9, may be merely at TRL 4 for monitoring the cold front at a geothermal operation. Each technology, even if it has been previously deployed, needs to be assessed for its TRL when being used in a different situation.

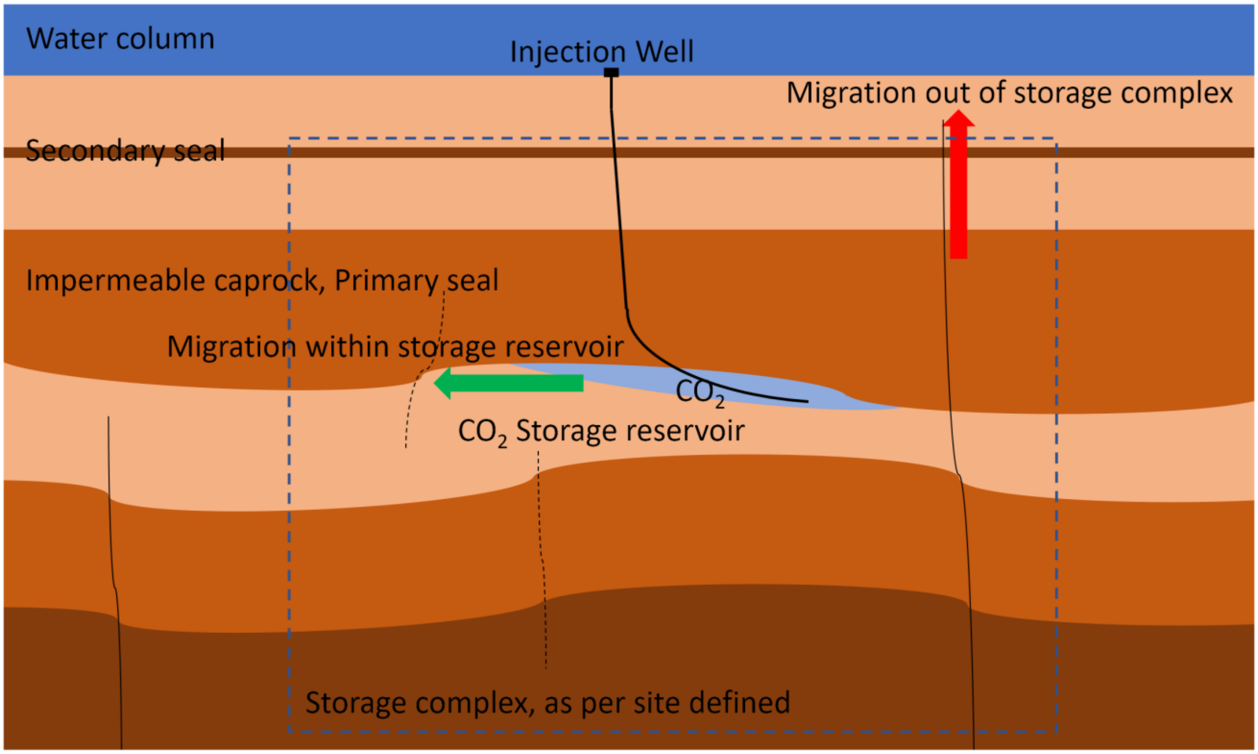

Figure 3: Schematic illustration of a CO2 geological storage site.

Key components of any CCS project are measurement, monitoring and verification (MMV). Each CCS project has to show that the project is being executed safely, securely and according to plan.

Regulatory requirements for the implementation of CCS in Europe are provided by the EU (this includes Norway and the UK.). For the DigiMon project we follow the EU regulations which specify the following requirements for monitoring:

- Detect migration of CO2 out of storage complex (
- Figure 3, red arrow)
- Migration of CO2 within the storage reservoir (
- Figure 3, green arrow).
  In principle, all induced change is to be detected including displacement of brine due to CO_2 flow
- Detect significant irregularities. Significant deviations in movement of CO_2 plume relative to model predictions, e.g. migration through existing or reactivated faults leading to migration out of the storage complex
- Detect any emissions into the water column.

From an operational point of view, an additional objective of monitoring can be to determine the storage capacity which is required to optimize injection within the capacity limits of the storage complex.

The TRA has been performed keeping the above-mentioned purposes and conditions in mind.

3 TRA process

In this chapter, we review the CTEs relevant for the DigiMon system, for monitoring a CO_2 storage site. For each CTE we systematically tried to report the answers to a predefined set of questions which together make up the TRA as defined by us (see Section 5.1. for the complete list of questions).

We grouped the CTEs in sections covering similar methods. The structure is as follows:

1. Surface and seabed seismic reflection methods
2. Borehole seismic methods
3. Passive seismic methods
4. Microgravity based methods
5. Seafloor deformation detection methods
6. Downhole pressure sensing
7. Temperature sensing
8. Chemical sensing based methods

3.1 Surface and seabed seismic reflection methods

3.1.1 Seismic reflection surveys

Seismic surveys are acquired to capture a snapshot of the velocity structure of the subsurface. Fluids in reservoirs change reservoir velocities as they migrate, hence changing travel times and reflection amplitudes. Repeated seismic snapshots of the sub-surface can be used to track the movement of fluids. Such animations – or time-lapse seismic data – have valuable applications in reservoir management and can, in the context of CO_2 storage, be used to map plume migration, both laterally and vertically.

Time-lapse seismic imaging can be applied to seismic refraction data, vertical seismic profiling (VSPs), cross borehole surveys, tomography, and seismic reflection data. For example, time-lapse seismic refraction data is useful in monitoring near-surface landslide conditions (e.g., Whiteley, et al., 2020).

Here we focus on (time-lapse) seismic reflection imaging, which is the main exploration tool of the petroleum industry and a well-developed technology operating at the highest TRL. Seismic reflection surveys provide a powerful tool for monitoring and assessing the efficiency of CO_2 injection. We finish this section with a discussion of the use and technology readiness of fibre optic cables as distributed acoustic sensors (DAS) in the acquisition of seismic reflection data.

Historical context

The first seismic reflection dataset was acquired in 1921 and for nearly 30 years the industry analysed reflections recorded by a single receiver from a single shot. Such single-fold reflection data were acquired along lines of sources and receivers deployed along the surface (2D imaging). In the 1950s, the concept of common-midpoint (CMP) stacking was employed to enhance the reflected energy and suppress unwanted energy from both coherent (e.g., surface waves) and incoherent noise (e.g., wind). The fold or data coverage – how many times a source-receiver midpoint is sampled - increased steadily as increasingly large arrays of seismic receivers were used to record increasingly large numbers of shots. Since the 70s, 3D seismic reflection surveys, where sources and receivers are deployed in a 2D grid across the ground surface, have become more and more common and provide a much better image of the subsurface structure in three dimensions.

Seismic reflection surveys on land normally use explosive (e.g., dynamite) or vibroseis (

Figure 4) sources recorded by arrays of geophones. The receivers are normally short-period single component sensors, but recent advancements have seen the deployment of three-component sensors which can be autonomous and more broadband in frequency content (e.g., microelectromechanical system (MEMS) based sensors). Such 3C sensors can be coupled with three-component vibroseis sources, resulting in nine-component datasets (e.g., Kendall et al., 2003), but such experiments are rare.

In marine settings, the most common type of receiver is a hydrophone streamer, which is normally used to recover air gun or water gun sources. Such data acquisition is acquired by a single ship towing a source array, tuned to minimize noise and bubble pulse signals, and a hydrophone streamer. More sophisticated receivers have been developed in recent years. For example, better spatial sampling has been achieved by incorporating MEMS sensors into a hydrophone streamer, thereby recovering the full vector wavefield (Eggenberger et al., 2014).

Figure 4. A mini-vibroseis source acquiring data at the Field Research Site (FRS) in Alberta, for the DigiMon project. The Field Research Site (FRS), a CO2 storage test site, is operated by Carbon Management Canada.

The early 90s saw the increased use of ocean-bottom cables for seismic monitoring of hydrocarbon fields (e.g, Rognø et al. 1999). Permanent reservoir monitoring (PRM) with seismic sensors was introduced on the Valhall field in Norway in 2003 (e.g., van Gestel et al., 2008) and several large fields, in Norway and elsewhere, have PRM systems installed to facilitate frequent time-lapse surveys. Cables with ocean-bottom seismic sensors are installed directly from a vessel, while autonomous nodes are deployed using remote operating vehicles (ROVs). Such seafloor instruments are commonly four-component (3C geophone/MEMS + hydrophone), which allows recording of conventional P-wave reflections, but also S-waves, which convert from P-to-S at the reflection point (e.g., Gaiser, 1999).

The fourth dimension

So-called 4D or time-lapse seismic data refers to the repeated acquisition of 3D surveys to image fluid flow across a region. Time-lapse seismic reflection monitoring goes back to the 1980s and the monitoring of steam-enhanced production of heavy oil (e.g., Pullin et al. 1987). More recently the advent of permanent reservoir monitoring (PRM) using dense arrays of seabed instruments have become valuable in mapping reservoir variations in time and space in sub-sea settings. As such, seismic imaging has become a reservoir management tool, rather than a sole exploration tool (e.g., Lumley, 2001). Time-lapse surveys provide better coverage than borehole monitoring and help to calibrate fluid-flow simulations. Such data can be used to identify reservoir compartmentalization and bypassed regions of the reservoir.

A key issue in 4D seismic monitoring is ensuring a consistent acquisition geometry, which raises questions of repeatability versus detectability. A good baseline survey is the first step. The repeatability of these surveys is now high with steerable streamers and the permanent deployment of cables on the seafloor. For example, in 2003 nearly 10000 sensors at 2500 locations were deployed over 120km of cable on the seafloor above the Valhall field in the Norwegian sector of the North Sea (e.g., van Gestel et al., 2008). Nevertheless, further complications arise due to variations in recording conditions and the effects of the overburden (Calvert, 2005). For example, source signal, noise conditions, receiver coupling, can be variable between surveys and without careful processing can lead to artefacts.

The observation of time-lapse signals in repeated seismic reflection surveys is now becoming routine. However, a remaining significant challenge is turning these observations into quantitative assessments. For example, an increase in reflection amplitude can indicate a change in fluids, but it is a non-unique exercise to estimate the change in fluid volume. Links with other geophysical indicators, fluid flow and geomechanical simulations and laboratory measurements, in conjunction with seismic modelling help to better constrain the inversion.

3.1.1.1 Conventional surveys

The seismic reflection method is particularly well suited to imaging stored CO_2 in saline aquifers or depleted oil reservoirs. In North America, such storage will most often occur on land, whereas in Europe, such storage will be sub-sea. Each environment presents its advantages and challenges. Below describes two examples of 4D seismic reflection imaging at two of the world's largest CO_2 storage projects – Weyburn-Midale in southern Saskatchewan and Sleipner in the Norwegian sector of the North Sea.

A good example of time-lapse seismic on land is the International Energy Agency (IEA) Weyburn-Midale CO_2 Monitoring and Storage Project, which has been testing monitoring methods to provide effective tracking of injected CO_2 in the subsurface at this site since 2000 (White, 2009). Here both 3D and time-lapse surveys (Figure 5) have been acquired, revealing how the CO_2 plume has migrated with time. A 9C 4D survey has even been acquired at this site (Kendall, et al., 2003). Other complimentary studies, such as amplitude variations with offset and azimuth have been used to map changes in fracture induced anisotropy (Duxbury, et al., 2010), which helps to better understand flow paths within the reservoir.

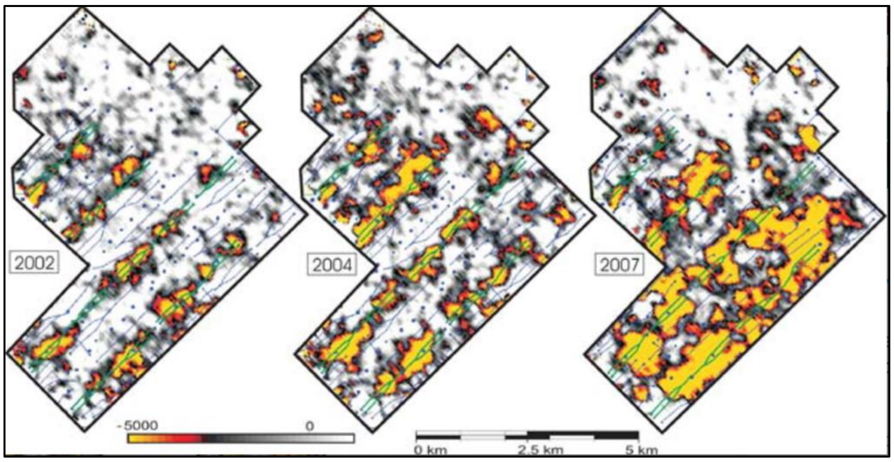

Figure 5. Time-lapse (2002, 2004, 2007) amplitude difference maps for the Weyburn-Midale storage project. Negative amplitude anomalies grow as CO2 migrates through this depleted reservoir. Adapted from White (2009).

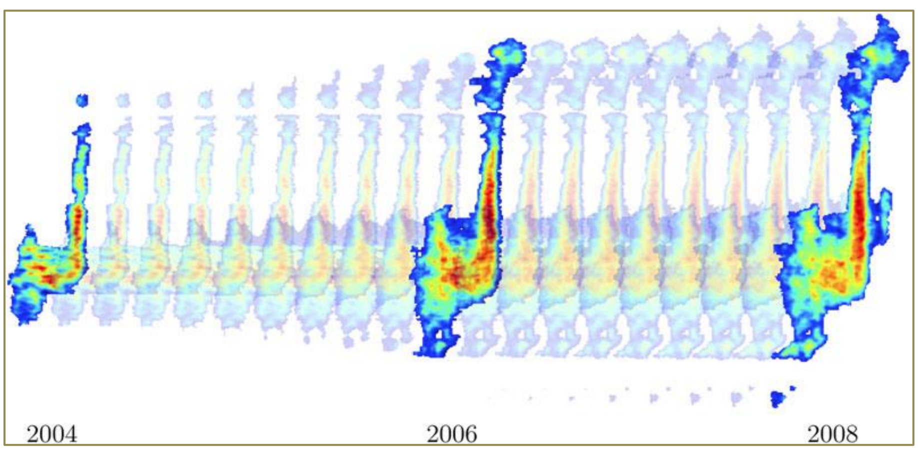

Figure 6. Interpolation of interpreted maps (transparent colours) of the Sleipner CO_2-plume between 3 conventional surveys (full-colour strength) made in 2004, 2006 and 2008 (Kiær et al. 2016). The red/orange colours indicate higher CO_2 concentrations.

Another well-known example is the CCS project at Sleipner. Since 1996, CO_2 has been injected into the Utsira formation above the Sleipner field in the North Sea. Here 3D seismic surveys have played an important role in monitoring the distribution of injected CO_2 (e.g., Arts et al., 2008); tracking CO_2 movement in geological formations (Boait et al., 2012); and estimating CO_2 saturation (e.g., Landrø and Zumberge, 2017) and CO_2 layer thickness (Kiær, 2015). These surveys allow a CO_2 plume to be tracked over time (e.g.,Roach and White, 2018) and interpolation between surveys allows plume growth to be better understood (Kiær et al., 2016; Figure 3). Time-lapse surveys are good at mapping the migration of CO_2 but assessing the quantity of CO_2 is still requires careful analysis of the data (Furre et al., 2015).

3.1.1.2 The advent of DAS and 4D seismic monitoring of CO_2 injection.

The use of fibre optic cable as distributed acoustic sensors (DAS) is a rapidly growing sector of geophysical imaging. DAS is now routinely used for VSP surveys (e.g., Naldrett et al., 2020), but has been slow to gain use in surface seismic reflection imaging. One of the first uses of DAS in surface seismic reflection surveying was performed at the Daly Field in Manitoba, where DAS compared favourably with more conventional geophone surveys (Kendall, 2014). More recent studies have shown the potential utility in using DAS reflection surveys, especially as dense station spacing allows better imaging of the near and deep surface simultaneously (Bakulin et al., 2020). Unlike geophone arrays, DAS systems are sensitive to uniaxial strain or strain rate along the fiber direction and thus provide a 1C recording, which makes identifying the directionality and polarization of incoming waves difficult. Acquisition using wound or helical fibres may help to address this shortcoming.

As DAS can be cheaply installed and repeatedly interrogated, it has great potential to be used for time-lapse seismic reflection studies of CO_2 storage and migration. It has been recently used in a 2D land survey at the Otway site in Victoria, Australia (Yavuz et al., 2019). Here both linear and helically wound cables are compared, with the suggestion that the helically wound cable was not worth the extra cost. Similarly, DAS was used to record surface orbital vibrator (SOV) sources at the Decatur CO_2 storage site in Illinois (Correa, et al., 2020). More recently, use in marine surveys has shown the potential for surface deployments of DAS cables in marine environments (Zhan, et al., 2020).

Despite promising results for nearly a decade, the use of DAS in recording seismic reflection surveys is still in its infancy. The technique holds great potential for time-lapse surveys, but likely using 2D lines, at least to start. Another advantage of DAS is that it can be deployed at the surface and downhole, with data recorded simultaneously using a single interrogator. This is the current fibre configuration at the FRS site in Brooks, Alberta (

Figure 4), which is operated by Carbon Management Canada (Lawton, et al., 2017).

3.1.1.3 Technology readiness

The use of 4D or time-lapse imaging using seismic reflection surveys is an established technology that is commercially at a very high TRL (9). The main downside to using such technology is the cost, especially as CO_2 storage projects will require monitoring for decades, if not centuries. Repeat 3D seismic surveys are expensive.

Even within this mature technology, scientific advancements are being made. Recently, measurements of spatial gradients of both translation and pressure have been demonstrated (e.g., Robertsson et al., 2008), in addition to the routine three-component (3C) translational and 1C water column pressure measurements. A particular benefit of spatial gradient measurements is that when combined with classic measurements, they allow a relaxation of the spatial sampling requirements and allow for powerful interpolation algorithms for sparse acquisition settings.

The use of DAS as a monitoring tool for CO_2 storage is not as well developed, although recent experiments have shown the potential. Despite being at a much lower TRL (5 to 6), such approaches may prove valuable in emerging monitoring strategies, including ambient noise imaging and concurrent monitoring of passive seismic emissions. A key aim of the DigiMon project is to demonstrate the use of DAS in monitoring CO_2 storage sites, using both passive and active seismic methods.

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3.2 Borehole seismic methods

3.2.1 Vertical seismic profile

In this section, we review the application of Vertical Seismic Profiles (VSPs) for monitoring of CO_2 in the subsurface.

The defining characteristic of VSPs, of which there are multiple types, is that either the energy source or the receivers are in a borehole. For most VSPs, geophones, accelerometers and sometimes hydrophones are located within the borehole and record (reflected) seismic energy originating from a seismic source at the surface (

Figure 7).

Vertical seismic profiling has been a useful measurement to obtain rock properties (velocity, impedance, attenuation, anisotropy) in-depth as well as to provide a seismic image of the subsurface. VSPs have the capability to image below a complex overburden, where for surface-based seismics the shallow and near-surface can obscure the image quality. Furthermore, a VSP can also give insight into seismic wave propagation and provide processing and interpretive assistance in the analysis of surface seismic data.

VSPs are often used for correlation with surface seismic data. VSPs are typically of higher resolution than surface seismic reflection data. With VSP data it is easy to tie well data to seismic data, as with a VSP we know both time and depth. Furthermore, VSPs have an important role to play when assessing rock and fluid properties close to the borehole. VSPs can provide in situ rock properties as a function of depth, particularly seismic velocity, impedance, anisotropy, and attenuation. VSPs can assist in understanding seismic wave propagation (e.g., source signatures, multiples, and conversions). VSPs can also assist in understanding and creating reflectivity images, and provide valuable information in further surface seismic data processing and interpretation.

Conventional VSPs often use multicomponent clamped geophones or accelerometers to record the seismic wave field in all directions. When using DAS, we are not able to sample the seismic wavefield in such a rich way. Typically the dynamic strain recorded by DAS has a cosine squared relation to the P-wave angle of incidents (which is different to the cosine relation of a single component geophone). Furthermore, the DAS fibre is normally oriented in line with the well, although other geometries do exist, like helically wound fibres or straight fibres wound helically around the well.

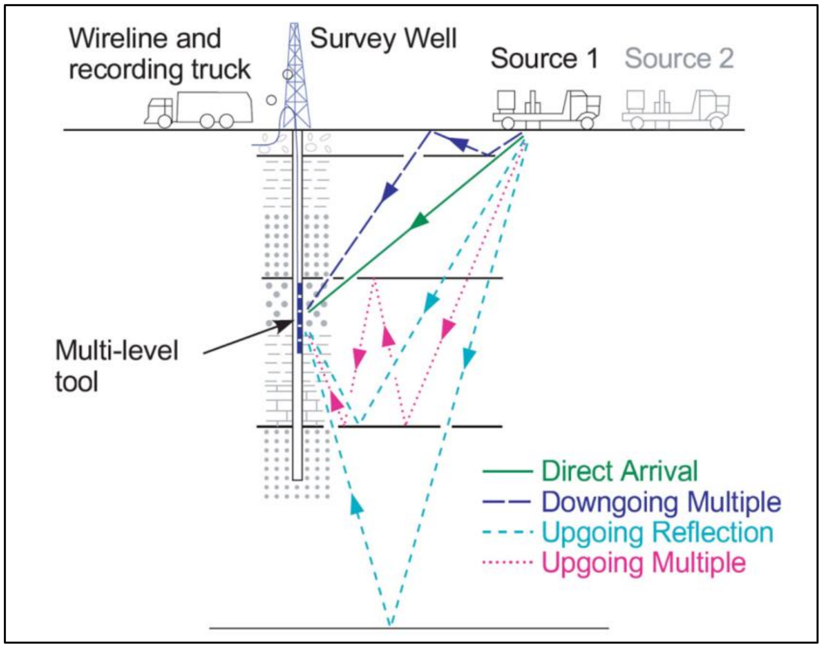

Figure 7. The basic components of a VSP survey are a seismic source, wireline and downhole receiver array, and a recording/wireline truck (DiSiena et al., 1984). In a DAS-VSP survey, the downhole receiver array is a DAS cable.

This TRA builds on article reviews (see references at the end of this section) and dedicated investigations of field and modelled data. Our findings are listed in the following sections.

3.2.1.1 Geophone, accelerometer, hydrophone VSP

A VSP uses the reflected energy at each receiver position to image the near well area (

Figure 7).

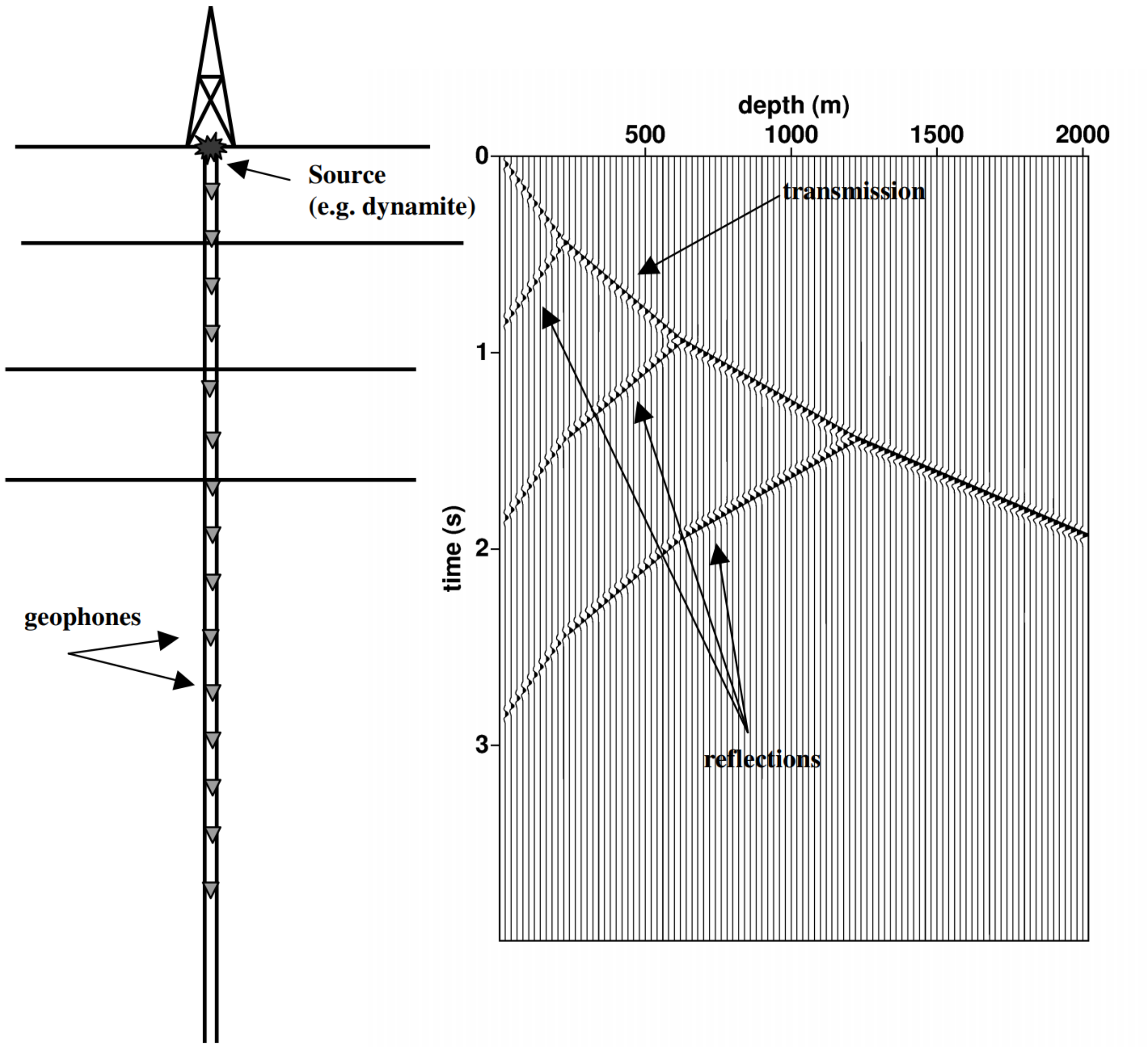

Figure 8. Zero-offset Vertical Seismic Profile; zero-offset means no horizontal distance between source position and the well. (TUDelft OpenCourseWare, Intro_reflection_seismics_chapter_6.pdf)

Figure 8 shows a configuration for a zero-offset VSP. Zero offset means that the source is situated right on top of the borehole, i.e. no offset exists in the horizontal position. In this figure, a linear event emerging from time t = 0 can be observed in the obtained recordings at depth, which can be interpreted as a direct wave from the surface to the receiver. The receivers (geophones/hydrophones) spacing for a VSP is often in the range of 25 m. Note that the horizontal axis represents depth since we put the recordings of the receivers at different depths next to each other. Also note that below the first layer, i.e. the receiver recordings taken inside the second layer, the slope becomes different; this is due to the different velocity inside the second layer. It can be seen from this direct arrival that we can use the slope of the event to determine the seismic velocity, either being the average velocity from the surface to the receiver or the local seismic velocity between two consecutive receiver positions.

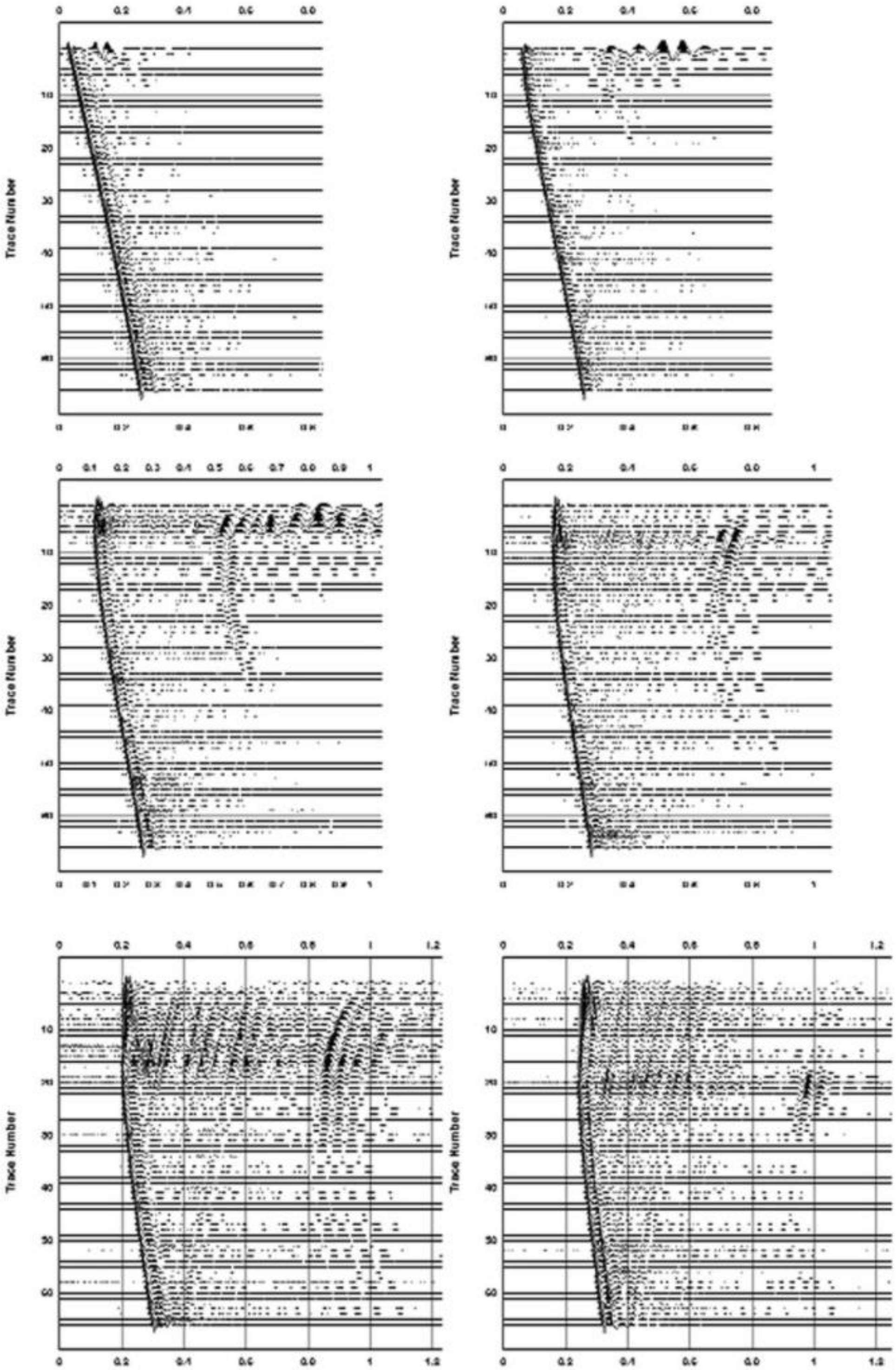

Figure 9. Vertical channel VSP data from six offsets of a survey in the Pikes Peak heavy oilfield, Saskatchewan (Stewart, 2001).

Figure 9 shows recordings of six shots in a VSP survey in the Pikes Peak heavy oilfield, Saskatchewan. The source offsets were 23 m, 90 m, 180 m, 270 m, 360 m, and 450 m. Note the relatively straight line of the first arrivals with depth. Moving to farther offsets the shallow first arrivals are upcoming refractions. The curved arrivals, later in the data, are interpreted to be source-generated shear waves - which are fairly common even on the vertical geophones

The various types of VPSs making use of conventional sensor arrays are regularly being applied and are on the market for many decades now. These types of VSP surveys are reviewed to have a TRL of 9, in many environments and applications. The application of VSP in (onshore) CCS has been performed and described in Luo et al., 2018. Extending the technique to offshore CCS, even though not performed anywhere before, will most likely be successful without any additional research needed.

3.2.1.2 DAS-VSP

In this section, we review the use of DAS-VSP to monitor the saturation of the fluids in the storage site and possibly the overburden. The products of DAS-VSPs are mostly the same as those of conventional VSPs. Often these are slowness values and corridor stacks. DAS-VSP nowadays is one of the most mature and versatile applications of DAS.

For DAS-VSP, the fibre can be installed in various ways in the borehole, e.g., permanently installed behind the casing or temporarily in the tubing, by making use of wireline surveys (Pevzner et al., 2020). A significant and truly disruptive advantage that permanent fibres make is that they make well interventions unnecessary and make VSP monitoring truly non-intrusive. This enables contractors to acquire data, quickly and on-demand. Mainly because of it's non-intrusive behaviour DAS-VSP has changed how borehole seismic data is acquired. For the receiver array, it is now enough to connect an interrogator to a fibre coming out of a well, where in the past there was the need to use heavy equipment to lower down large and heavy geophone arrays.

In 2009, DAS-VSP still very much looked like check shot data. Currently, processed DAS-VSP data can exceed signal to noise ratios of conventional VSP surveys. Although quality assessment of DAS-VSP data still requires a thorough investigation e.g. of the influence of near-well transfer functions (role of casing, tubing, cementation, wash-outs, etc.) for various wave-types, often, for timelapse monitoring, the meaning of absolute amplitudes is of less importance when comparing between vintages. Hence DAS-VSP operations are currently widely commercially available

Because of the ease of use of permanently installed fibres, DAS-VSP is especially useful for reservoir surveillance (timelapse monitoring) at an attractive cost.

DAS-VPS performs best in geometries with near-vertical wells. This is explained by the cable-orientation commonly being aligned with the well. In near-vertical scenarios, the limited broadside sensitivity of DAS is negated. But DAS-VSP can also be used in highly deviated and horizontal wells where deployment of conventional geophone arrays is complicated. Drawbacks of DAS-VSP are high level of the noise floor, directivity pattern, attenuation of the signal with the length of the fibre cable and the uncertainty of the depth determination, although advancements are being made on an almost daily basis.

3.2.1.3 Relationship with other CTEs.

The processed data from the VSP is often integrated into the earth model in which surface seismic plays a large role. VSPs typically only covers the area around the well, up to a max of approx. 500 / 1500 meters depending on the geometry of the survey, but in fairly high resolution. Surface seismic can cover many square kilometers, albeit often only in lower resolutions. Data from DAS-VSPs is often used for velocity model building. VSPs can deliver very accurate interval velocities, which can also be of great value to the data processing and interpretation of other seismic methods.

Furthermore, DAS-VSP typically having a long and dense receiver array, can supply valuable data when it comes to the use of full-waveform techniques. DAS-VSP, because of it's high repeatability and resolution is very well suited for monitoring changes in the subsurface e.g. caused by CO_2 storage activities.

3.2.1.4 History and current status

The technology development of DAS-VSP has taken large steps since it was first tested in the early 2000's. Faster, more accurate, more sensitive and less costly interrogators have made it possible to sense the smallest of strains/vibrations on fibres buried deep and along the well trajectory.

DAS-VSPs has been deployed from deepwater enhanced oil recovery (EOR) environments to onshore CCS (demo) sites like Quest, Aquistore, Otway and Ketzin (e.g., Correa et al., 2018; Correa et al., 2019; Harris et al., 2016; Harris et al., 2017; Whiye et al., 2019). Current recordings show that DAS-VSPs can be just as sensitive as downhole geophones, and through its denser spacial sampling it can even outperform conventional geophones (

Figure 10).

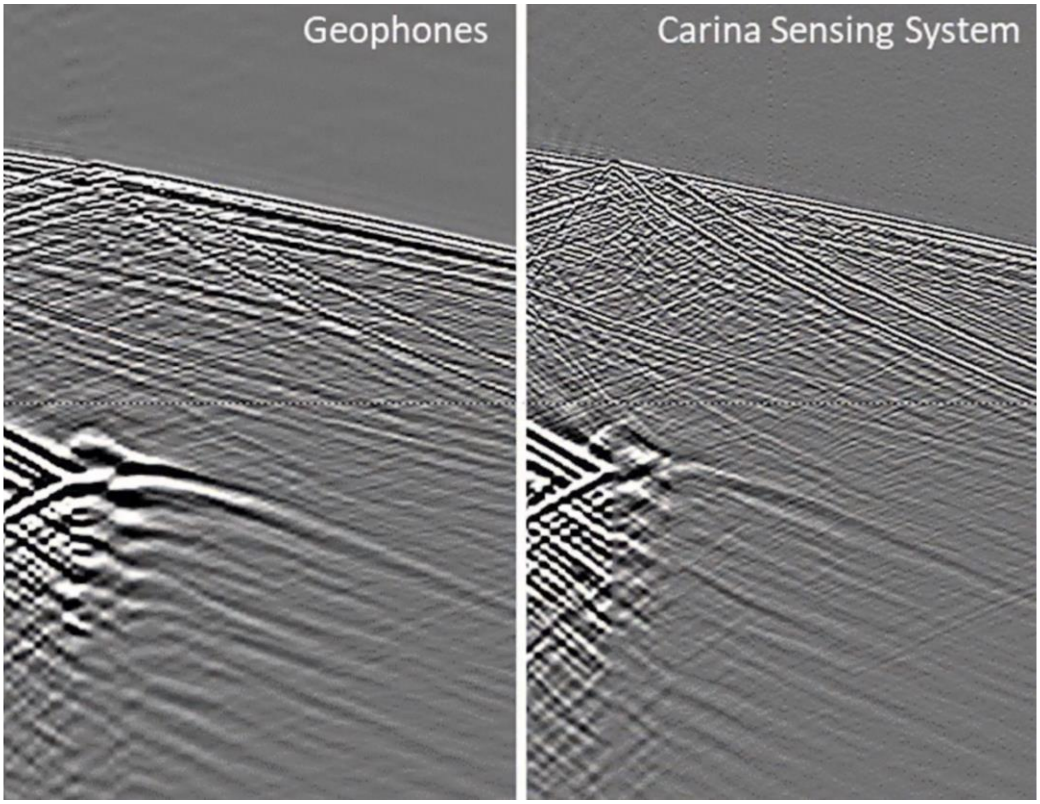

Figure 10. Comparison of a conventional VSP record with a DAS-VSP record (from Silixa website, recorded at CO2CRC Otway site).

DAS-VSP has allowed the application of VSP to become non-intrusive and low-cost. By doing this DAS-VSP enabled operators to rapidly monitor for subsurface changes, in a highly repeatable, low cost and unintrusive way.

Multiple field trials have indicated that onshore DAS-VSP is an affordable, highly repeatable (

Figure 11) technique and potentially very relevant for CCS operations, and the same goes for DAS-VSP in the offshore environment. DAS-VSP allows for relatively low cost and low impact, high-frequency monitoring campaigns, capable of subsalt (or otherwise complex overburden), high-resolution imaging which could very much complement or be complemented by other types of data (seismic or otherwise).

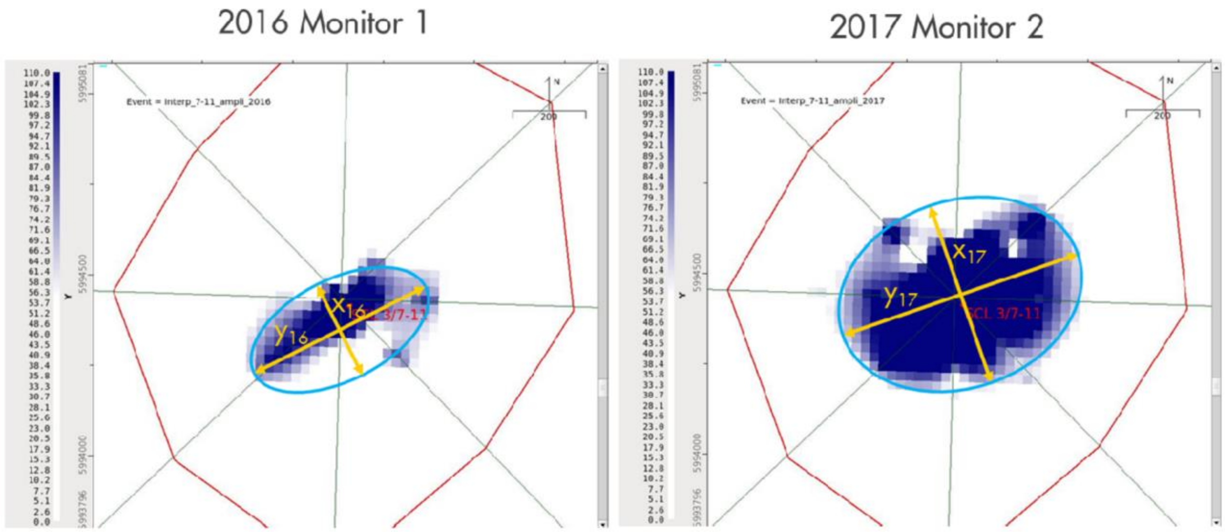

Figure 11. Map view of interpolated amplitude difference for the 2016 and 2017 DAS-VSP repeat surveys. Onshore Quest, Canada. DAS-VSP reapatability NRMS<10% timelapse difference of DAS VSP. Fibre cemented behind casing. (Halladay, 2018).

DAS-VSPs have been performed on- and offshore, although for offshore measurements, often due to regulations additional challenges can be encountered. However, both dry and wet tree deployments are possible for DAS, an important aspect for subsea applications. A large part of development takes place on the processing of DAS-VSP data e.g. wavefield deconvolution, making use of large VSP offsets, using AI for various problems, using passive data (seismic noise) to image targets, etc.

3.2.1.5 Technology Readiness

DAS-VSP is heavily being used to monitor subsurface operations, on- and offshore. Because we only know of DAS-VSP for CCS in the onshore environment we give DAS-VSP a TRL of 8.

Table 4. TRL DAS-VSP

Top-level question		Yes/No	If yes, then basis and supporting documentation
TRL 9	Has the actual equipment/process successfully operated in the full operational environment?	No	Has not been applied offshore for CCS, but for oil and gas
TRL 8	Has the actual equipment/process successfully operated in a limited operational environment?	Yes	Applied at Quest, CA, large scale onshore CCS, Halladay, 2018
TRL 7	Has the actual equipment/process successfully operated in the relevant operational environment?		
TRL 6	Has prototypical engineering scale equipment/process testing been demonstrated		

	in a relevant environment; to include testing of safety function?		
TRL 5	Has bench-scale equipment/process testing been demonstrated in a relevant environment?		
TRL 4	Has laboratory-scale testing of similar equipment systems been completed in a simulated environment?		
TRL 3	Has equipment and process analysis and proof of concept been demonstrated in a simulated environment?		
TRL 2	Has an equipment and process concept been formulated?		
TRL 1	Have the basic process technology process principles been observed and reported?		

3.2.1.6 References

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3.2.2 Crosswell Tomography

Seismic crosswell tomography provides high-resolution 2D or 3D images of shear wave velocities (V_S) and compressional wave velocities (V_P) between boreholes. In this context, the term tomography (from the ancient Greek τομή =" cut" and γράφειν =" to write"), refers to various imaging techniques that can determine the internal spatial structure of an object and represent it in the form of sectional images (also called slice images or tomograms). In seismic tomography, the line on which the integral values are obtained is usually the (in inhomogeneous material not straight) connecting line between seismic source and receiver (travel path). This can be determined numerically by ray-tracing methods. The used integral value (sum of values) along this line can be either the traveltime of the wave (traveltime tomography) or the attenuation (amplitude tomography). The traveltime results additively from the traveltimes in individual sections of the travel path defined by the slowness (1/v) in the corresponding path elements. In amplitude tomography, the total attenuation (amplitude decrease) results multiplicatively from the attenuations in the individual path elements. To arrive at an integral value (sum value), the logarithms of the amplitudes are used, whereby the multiplicative connection becomes an additive one.

Seismic tomography can be applied in different geometries, such as crosswell (between two boreholes), VSP (Vertical Seismic Profiling), curved ray path tomography, surface wave tomography, teleseismic monitoring and microseismic tomography (ambient noise). In the following, we only refer to crosswell (or crosshole) tomographic measurements.

A literature review is conducted in this TRA, focusing on the feasibility of crosswell tomography for CO_2 site monitoring. Here, the applicability of onshore seismic crosswell tomography within CCS monitoring task is to monitor the (1) CO_2 plume, (2) possible leakages or migration paths and (3) well integrity should be assessed.

1. Laboratory and field experiments have shown that the effects of CO_2 saturation on seismic properties of rocks are strong and detectable (Harris et al., 1995, Nolen-Hoeksema et al., 1995, Wang et al., 1998). Several studies showed that injection of CO_2 into aquifers or reservoirs would reduce the seismic velocity of the reservoirs or aquifers and that seismic tomography can be used to image the velocity reduction in the injected geological structures (e.g. Saito et al., 2006, Ajo-Franklin et al., 2013, Boehm et al., 2015, Wang et al., 1998). For instance, the results of time-lapse crosswell seismic tomography within the Japanese Nagaoka project indicate an area of P-wave velocity decrease possibly due to CO_2 saturation, and the CO_2-bearing zone near the injection well expanded clearly along with the formation up-dip direction during CO_2 injection (Xue et al. 2005). In addition, Wang and Nur (1989) and Daley et al. (2008) applied time-lapse traveltime tomography to cross-well data from the Frio CO_2 injection site and found a velocity decrease in the sandstone aquifer of about 500 m/s due to the presence of CO_2. At the Ketzin pilot site the crosswell seismic measurement was designed to follow the migration of CO_2 at small scale during

the injection and the experiments showed that borehole seismic methods could image the distribution of CO_2 in the reservoir and contribute to the quantification of geometrical and petrophysical parameters of the plume (Goetz, 2014).

2. Yang et al. (2018) reported that the seismic method is much more sensitive to a small gas leak than the gravity method, which is another geophysical method. The geophysical signal strength strongly correlates with CO_2 leakage mass but not with the brine leakage mass. The seismic methods are sensitive to changes in formation density or CO_2 saturation where the CO_2 gas displaces the shallow groundwater and is trapped below a confining layer. Especially time-lapse crosswell imaging is an effective way for subsurface CO_2 monitoring in enhanced oil recovery both enhanced oil recovery and sequestration (e.g. Gritto et al., 2004; Majer et al., 2006, Skov et al., 2002; Arts et al., 2004).

Well integrity is an essential issue because wells and annuli in cement can act as leakage pathways for CO_2 from the reservoir to the surface (Celia et al. 2004). At the Nagaoka CO_2 Injection Site, time-lapse ultrasonic and cement bond logging have been employed to investigate the observation well integrity (Nakajima et al. 2013). Goetz (2014) stated that borehole seismic monitoring can be applied to the observation of layers above the reservoir, for the detection of leakage paths or the inspection of well integrity.

3.2.2.1 Function

Crosswell seismic tomography fills the gaps between boreholes. The crosswell seismic tomography has a at least four times higher resolution,in comparision with conventional (VSP and surface) seismic data (Pereira and Jone, 2010). There are three basic types of seismic waves, P-waves, S-waves and surface waves. Tomographic measurement usually uses P-waves and S-waves with the two polarization directions (SH and SV). In general, the S-wave tomography provides a much higher resolution but the processing of S-wave data requires more sophisticated and skilled personnel and is time-consuming. Therefore, in most cases, P-wave tomography is used to predict high-resolution spatial continuity of lithological structures where P-waves are generated in one borehole and being transmitted to the other. However, the additional measurement of SH- and SV- velocities allow the joint inversion and the assessment of stress-induced anisotropy.

3.2.2.2 Relationship to other CTEs

In the case of medium-scale or large-scale subsurface monitoring, crosswell tomography can be seen as an added value of passive continuous recording for induced seismicity with e.g. ambient noise interferometry. Also, the joint analysis and interpretation of crosswell and VSP measurements helps to create models depicting the existing natural systems and to describe the ongoing processes and their impacts in the subsurface.

3.2.2.3 Development history and status (tomography, seismic sources, seismic receivers)

The P-wave tomography is a common approach for subsurface characterization and has become an integrated tool routinely used for surveying development sites considered for major building projects, such as dams and building constructions. However, the groundwater table strongly influences the P-wave, and therefore, its application for deriving geotechnical parameters is limited. Cosma et al. (2009) applied traveltime tomography to the time-lapse cross-well data acquired at the Ketzin Site to monitor the CO_2 injection. Their results indicated that conventional P-wave cross-well traveltime tomography could not map the CO_2 distribution at the time of the surveys since no significant first arrival traveltime variations were observed. In contrast, shear waves react sensitively to changes in dynamic soil parameters, such as shear strength or modulus of elasticity. Due to the heterogeneous structure of the soil, these parameters also have a 3D structure. The standard P-wave tomographic acquisition geometries are generally applicable for high-resolution S-wave tomography. S-wave tomography is employed internationally and nationally in a relatively limited number of studies predominately motivated by academic interests. P- and S-wave tomographic results of previous studies show a significantly higher velocity contrast for S-wave tomograms (factor 3) than P-wave tomograms (factor 1.5). A joint inversion of S- and P-wave tomographic data allows reducing the inherent ambiguity of tomographic reconstruction techniques.

Geophones, accelerometers or hydrophones and, in recent years, fibre optic cables (Distributed Acoustic Sensing, DAS) are used to record seismic waves. Seismic receivers differ in their natural frequency and sensitivity and must be selected according to the specific monitoring task. For some long-term monitoring CCS tasks the seismic receivers are permanently installed behind the borehole casing and therefore, the saline aquifer can be a limitation regarding the usage of this technique. The acquisition with hydrophone strings is a standard, cost-effective and efficient strategy to acquire high-quality seismic measurements in various subsurface environments. For our onshore experiment, we use the hydrophone string BHC5 (Geotomographie GmbH) used to receive P-waves in water-filled boreholes. The BHC5 consists of a downhole cable containing a Kevlar tension string and a number of molded hydrophones at pre-defined intervals. On the other hand, the Multistation Borehole Acquisition System (MBAS) is digital three-component geophone strings used to receive P- and S-waves and where up to ten individual stations with tri-axial sensors are connected. The MBAS provides a great potential to record P- and S– waves simultaneously over a certain depth interval allowing a rapid and efficient S-wave tomography. Geotomographie GmbH redesigned such a MBAS system to be applied at the DigiMon test at Svelvik. This system allows a reduction in measurement effort and therefore their related costs due to the simultaneous measurement at 8 depths.

Also, within the project, a novel SV Source was developed. Therefore, the generation of P, SH and SV waves using the same high voltage impulse generator is possible.

3.2.2.4 Relevant Environment

For the CCS application, it is required to collect all available information about the subsurface also while installing the boreholes. A proper knowledge base allows reliable interpretation of the results. Some primary factors influence crosswell results: the proper installation of the needed boreholes, borehole distance, location and extent of objects of interest, seismic velocity contrast, noise level and noise sources.

3.2.2.5 Uncertainty

An assessment of the uncertainty in the data is complex and site-specific and therefore a complex task. As stated in the previous subchapter, the benefit of crosswell measurements depends on the existing velocity contrasts in the subsurface. Uncertainty is related to field environment (e.g. noise sources such as traffic or other industrial sources), field setup (e.g. borehole distance, proper borehole installation), data acquisition (e.g. proper coupling, Signal/Noise ratio), data processing (e.g. error in picking arrival times) and data interpretation.

For the crosswell tomography, the unknown region between the boreholes is discretized into "n" pixels to provide a tomographic image of the generated spatial distribution of wave velocity. It is clear that higher resolution (smaller seismic source positions) implies smaller pixel size and therefore a higher number of unknowns which turn out to be a bad conditioned problem. It shows that the smaller the number of receivers that are accessible for certain signal source positions, the more ill-conditioned the problem is. Likewise, the wavelength used determines the maximum achievable resolution. Anomalies smaller than the wavelength are not resolvable. Diffraction around low-velocity anomalies e.g. an anomaly with diameter D=wavelength in the center is visible if borehole spacing < 5*wavelength. As already mentioned, there must always be a velocity contrast between the anomalies and the surrounding medium and the diameter of the anomaly must always be smaller than the borehole distance.

Boundary conditions such as borehole casing, the relative impedance between casing-soil affect the radiation patterns and the effective size of the source. Another problem is that in the near field close to the source, the waves cannot propagate properly: due to (1) the superposition of dilation and shear waves and (2) the interference of wavelets generated in different regions on the source side. Material losses cause additional attenuation, and the amplitude of the signal must be greater than the noise. An increased S/N ratio at the receiver can be achieved by appropriate filtering or stacking. From the sampling theorem, it is known that the smallest possible wavelength must be at least twice the distance between the recorded positions to give good results.

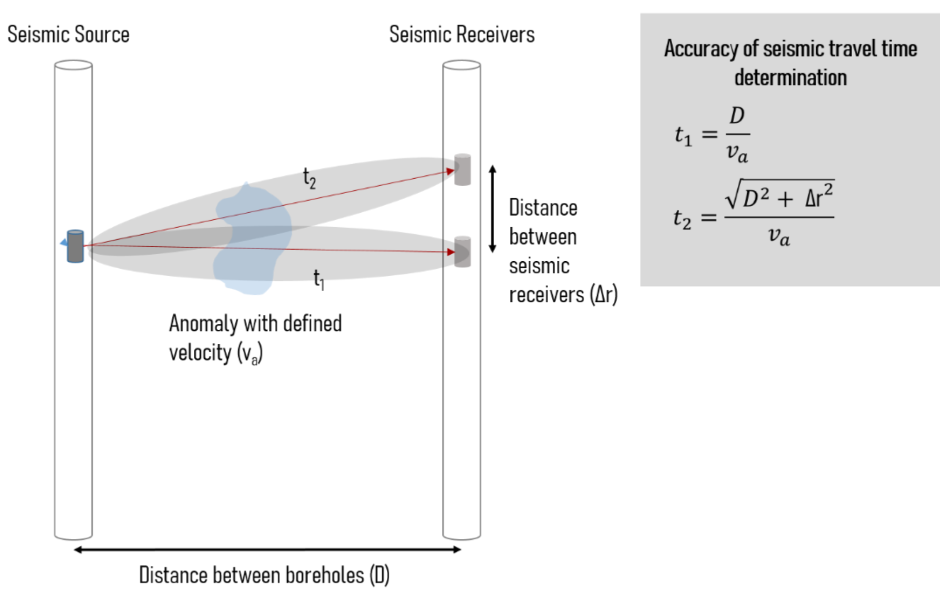

Figure 12. Accuracy of travel time determination for different rays

For CCS application the knowledge of the ongoing processes during injection is essential for seismic data interpretation. It is expected that e.g. the P-wave velocity always decreases with gas injection. Therefore, the tomographic inversion scheme should be restricted considering only velocity decreased after injection start. Also, data about the expected velocity contrast are helpful to set up the optimal measuring scheme.

3.2.2.6 Comparison of the relevant environment and the potential environment of onshore CCS site

Depending on the type of seismic wave to be excited, the sources can be divided into P-wave sources and S-wave sources. Experiments with P-waves are very relevant for CO_2 storage because the velocity decreases dramatically as a function of the percentage of gas inside the pore volume. In addition, S-waves are also relevant since their velocities are dependent on dynamic properties that vary during the CO_2 injection progress. Especially, the S-wave is sensitive to stiffness changes that are expected during the injection. S waves are generated in distinctly different SH and SV polarization components and with the novel development Geotomographie GmbH can now provide a P-, SH- and SV Source using the same 5000V power supply. This source allows for a comprehensive characterization of the elastic soil parameters. Compared to the baseline measurement, changes in the ratio of SH/SV can be directly assigned to a stress redistribution in the rock due to pressure changes and can be reproduced in a detailed and spatially accurate image by seismic tomography.

Also, an application of the re-designed MBAS- System to monitor CO_2 plume, possible leakages or migration paths and well integrity is novel and will be tested within the project.

3.2.2.7 Technology Readiness

This redesigned MBAS system is successfully demonstrated through tests the performance for its intended operations and the successful field tests in Svelvik the TRL level increased to level 5 to 6.

Within the DigiMon project, a novel SV Source (BIS-SV) was developed and generates vertically polarized shear waves (SV) and compressional waves (P). In addition, the already available borehole source BIS-SH from Geotomographie GmbH generates horizontally polarized shear waves (SH) and compressional waves (P). In combination with the novel BIS-SV, a comprehensive characterization of the elastic soil parameters is achieved with the available measurement data from P, SH and SV waves.. All seismic shear wave sources and the P-wave source use the same HV impulse generator which improves the practicability, reliability and the cost effectiveness. The novel SV- source improves practicability of S-wave tomography by faster handling and therefore higher time and cost effectiveness.

This BIS-SV source is successfully demonstrated through tests. The successful field tests at Svlevik indicated an increase in the TRL level to level 5 to 6. However, additional field applications could increase the TRL level to 7 (The equipment has successfully operated in the relevant operational environment).

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3.3 Passive seismic methods

3.3.1 Microseismics

Seismic activity in and around CCS reservoirs can provide valuable information on the movement of CO_2 and the characteristics of a storage reservoir. Any subsurface activity that alters the state of stress in the ground is capable of triggering seismic activity on pre-existing faults, and in the case of CCS, this can be caused by the movement of CO_2 within the subsurface. Microseismic monitoring has become an established method of imaging the subsurface for industrial applications, such as enhanced geothermal systems (e.g. Kwiatek et al., 2019), hydraulic stimulation of “tight” hydrocarbon reservoirs (e.g. Kettlety et al., 2021), and has been successfully deployed in several CCS projects (e.g. Stork et al., 2015). The technology provides an important tool for monitoring CO_2 plumes and potential breaches from the containing reservoir.

The primary goal of microseismic monitoring is to detect, locate and characterise very small earthquakes, which occur at or below the micro-scale of seismicity ($M<2$). These typically relate to fault ruptures which are 10s of meters in length that produce displacement amplitudes often at the detectability limits of seismometers (Bohnhoff et al., 2009). The position of these events within a storage reservoir provides valuable information on the extent of the CO_2 plume, while the waveforms can be used to characterise the fracture properties and stress regime within the reservoir. The resolution of these datasets can be significantly improved by lowering the detectability limits of the microseismic array. The detectability limit is a function of both the instrument and the background levels of ambient seismic noise. One approach to improving the signal to noise ratio (SNR) is through applying array processing methods (e.g. Verdon & Budge, 2018) which require relatively highly spatially sampled datasets.

3.3.1.1 Geophone/ hydrophone/ OBS

Microseismic datasets can be acquired using surface and/ or borehole sensors which typically comprising of either geophone accelerometers or broadband seismometers. Within a borehole, regularly spaced strings of 3-component geophones are generally deployed which block the borehole annulus preventing other operational activities using the well. The spacing between borehole geophones is generally relatively large to increase the spread of sensors throughout the well. On the surface, instrumentation generally needs to have much higher sensitivity levels due to attenuation within the near-surface layers (Butcher et.

al, 2020). In this setting, 3-component broadband seismometers are typically deployed, as these have low instrument noise levels and are more sensitive to low-frequency signals.

Combining both borehole and surface sensors is a commonly used configuration for monitoring induced seismicity, with numerous examples published case examples (e.g. Baird et al., 2013; Clarke et al., 2019; Igonin et al., 2021; Skoumal et al., 2019). This technology is well developed and fully operational for commercial projects. As a result, the TRL of microseismic monitoring using broadband seismometer and geophones equipment configurations can be considered to be at a TRA level 9.

3.3.1.2 DAS

The adoption of DAS for microseismic monitoring is at a relatively early stage. Although the instrumentation is well developed and increasingly deployed for commercial projects, several technical challenges are still to be overcome. DAS has the potential to significantly improve the resolution of microseismic datasets due to high temporal and dense spatial sampling (Verdon et al., 2020). Additionally, the same DAS dataset can be processed simultaneously to provide both microseismic and strain information (e.g., Diller and Richter, 2019), thereby enhancing the information value. However, the single component nature of the measurement and challenges in correcting for the instrument response pose a number of significant limitations that still need resolving. The single-component nature of the measurement not only results in site and orientation effects due to the limited broadside sensitivity of DAS along straight fibres (Baird et al., 2020) but also prevents the use of other standard methods such as seismic anisotropy methods for fracture analysis (Teanby et al., 2004). DAS microseismic monitoring has been deployed at onshore CCS sites (Quest, Aquistore) and enhanced geothermal sites (e.g. Lellouch et al., 2020) but so far no offshore deployments have been made. Therefore, while processing methodolgies are well developed for conventional seismometers, they are not as well developed for DAS instrumentation which reduces the TRA level to 7/8, with the potential of increasing to 9 with further development.

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3.3.2 Ambient noise interferometry

Passive and continuous seismic recordings capture signals from multiple sources, such as earthquakes and explosions, which have clear onsets or impulse like signals. In most cases, however, what is mostly recorded is noise, which can be instrumental or ambient. Neither of the two is welcomed by seismologists, who generally focus on impulse responses from earthquakes or active sources for imaging the subsurface. All the other seismological technologies presented in this report are based on impulse-response signals, for instance, 4D seismic or cross well tomography.

Ambient Noise Interferometry (ANI) is a technique that reconstructs ambient noise, the frequently discarded element of the seismic recording, into impulse signals. Although developed in the past 20 years, the technique itself is now mature and has been widely used in various conditions and scales from onshore to offshore, from applied geophysical exploration to continental imaging. Under ideal conditions, the result of ANI compliment the other techniques which are included in this report. The advantages of ANI are that acquisition costs can be significantly lower, as an active source is not required, and the methodology allows for regular repeat monitoring of the subsurface. A potential disadvantage of ANI is its dependency on noises. Ambient noise is often not isotropic or broad band and might change spatially and temporally, which limits the resolution of ANI images.

A literature review is conducted in this TRA, focusing on the feasibility of ANI for CO_2 site monitoring. This focuses on the detection and location of potential seismic velocity changes as a result of CO_2 injection, plume migration or gas leakage.

3.3.2.1 Function

ANI is a technique that reconstructs ambient noises into impulse-like signals, thus the resultant interferograms can be used by other seismological methods (mainly for surface wave tomography, 4D seismic, and coda wave interferometry) to image and characterise the subsurface.

3.3.2.2 Relationship to other CTEs (passive, velocity, structure, instrument)

In the case of large-scale subsurface monitoring, ANI can be seen as an added value of passive continuous recording for induced seismicity. As the technique uses ambient noise, with generally lower amplitudes and frequency content compared with induced earthquakes, it does however require care with the selection of seismic instruments.

The most common application of ANI is the retrieval of the seismic surface wave response between pairs of seismic stations. The dispersion of surface wave velocity is determined by dominantly S-wave velocity changes as a function of depth ---- high frequency signal are sensitive to near surface S-velocity, lower frequency signals are sensitive to deeper layers ---- which are used to build 3D S-wave velocity models. Compared with 3D seismic surveys, such as seismic reflection, the approach provides a lower resolution S-wave velocity model which is relatively insensitive to subsurface interfaces. When body waves can be retrieved from ambient noise field, these may be subsurface reflections and provide a lower resolution equivalent of the 3D and 4D seismic reflection surveys.

3.3.2.3 Development history and status (invention, history, introduction, body wave, surface wave)

The basic concept of ANI was firstly introduced by Aki (1957), who used ambient noise to extract surface waves, and Claerbout (1968) who showed that the reflection response at a station can be obtained from the autocorrelation of a seismogram. Lobkis & Weaver (2001) successively retrieved Green's Function between two passive Ultrasonic transducers, which triggered the development of coda wave interferometry (Snieder et al., 2002) and the ambient noise interferometry (Shapiro & Campillo, 2004). For a more comprehensive introduction to the development and applications, we refer to the review by (Snieder & Larose, 2013), and the textbook by (Schuster, 2009) for applications on seismic exploration.

For the simple case of a 1D medium, it is easily shown that the cross-correlation of random noise recorded by two stations gives a pulse at the propagation time between the two stations. This is similar to the situation of having a source at one station and a receiver at the other. Extensions to 2D and 3D media require additional conditions, such as a uniform distribution of sources surrounding the two stations. The main contribution to the cross-correlation then comes from the sources that produce the stationary-phase wavefield between the two stations.

As seismic waves can be divided between body waves and surface waves, the development of ambient noise interferometry can be divided into these two as well. After retrieving body wave responses, seismic imaging techniques can be applied (Brenguier et al., 2020; Nakata et al., 2011). A slightly variant of this approach uses transient body waves from identified noise or seismicity (Dales et al., 2017; Olivier et al., 2015; Ruigrok & Wapenaar, 2012).

While the most common application of ANI is the reconstruction of surface waves travelling along the earth surface (Snieder & Larose, 2013). To image the earth's lithosphere, the globally existent microseism noise can be used, which is caused by ocean-earth interaction at the frequency range of 0.02 to 2 Hz (Brenguier et al., 2008; Shapiro et al., 2005). It has been applied to various conditions from the near coast (Shapiro et al., 2005) to the deep continent (Yao et al., 2006). It requires low-frequency seismometers to capture low frequency, low amplitude ambient noise.

Stork et al. (2018) studied the suitability of repeat ANI tomography to monitor CO_2 at the Aquistore CO_2 storage, Canada. Their results suggest that repeat ANI tomography surveys, which uses the ballistic, i.e. direct / non-diffusive, wavefield, is not sensitive enough to the small S-wave velocity change there might be. Cheraghi et al. (2017) studied the same site with body waves, and showed retrieved body waves have a poor signal-noise ratio and are unsuited for monitoring. In another experimental site in Ketzin, Germany, Boullenger et al. (2015) investigated the feasibility of monitoring P-wave velocity reduction introduced by CO_2 gas injection. They mainly analysed P wave reflections in the autocorrelations of ambient noise and repetitive active shots.

Compared with the ballistic wavefield, it has been shown in many cases that the noise-cross-correlations coda, the diffusive wavefield, could be more sensitive to seismic velocity changes. Reported measurements reach 0.1% or even lower (Brenguier et al., 2008; Taira et al., 2018). However, it is still a challenge to accurately determine the location of velocity changes due to CO_2 injection. Firstly, because reservoir imaging at depths >1 km uses low-frequency signals with longer wavelengths and hence lower spatial resolution. Secondly, the multi-scattered diffusive waves have long and uncharacterizable wave paths, which further complex the localization of velocity changes.

3.3.2.4 Relevant Environment

Three primary factors influence ANI results. First, the characteristics of noise sources, such as microseism noise, anthropogenic noise such as traffic, factory, etc. are important. Different noise sources have different frequency contains and wave types (body wave or surface wave). Second, instrumentation needs to be sensitive enough in the frequency band of the noises of interest. Third, the relative position of the noises and instruments influences the results. To produce constructive interferograms, ideally, the dominant noises should be located within the stationary phase, or the noises are diffusive isotopically.

3.3.2.5 Comparison of the Relevant Environment and the Potential Environment of Offshore CCS Site

In offshore CCS settings, we expect to have strong microseism noise (Sladen et al., 2019; Spica et al., 2020; Williams et al., 2019), anthropogenic noise from operation platform (Behm, 2017; Bussat et al., 2016), induced seismicity as a result of CO_2 injection (Goertz-Allmann et al., 2017) or teleseismic events (Ruigrok & Wapenaar, 2012). With a high-quality ocean bottom geophone (4.5 Hz) array, there is potential to retrieve surface waves (0.2 to 1 Hz), as demonstrated by previous studies in near coast environments (Wang et al., 2019). With a broadband ocean bottom seismometer array, it should be possible to retrieve a higher signal-noise ratio surface wave down to frequencies 0.02 Hz (50 s).

There is also potential to retrieve body waves, generated by ocean gravity waves (Spica et al., 2020). For an ocean bottom DAS array, multiple previous cases have recorded strong surface wave noises (Spica et al., 2020; Williams et al., 2019). Spica et al. (2020) successfully inverted the S-wave profile from DAS recorded microseism noise. Notably, most of the currently published cases have DAS cable near perpendicular to the coast, which is favourable for DAS to record microseism noise travelling from the ocean.

3.3.2.6 Technology Readiness Level Determination

ANI is widely used to image the deep subsurface and can be considered a relatively mature technique for this purpose with a TRL of 6 or 7. However, for the application of monitoring CO_2 within the shallow subsurface, there are very limited examples of successful case studies. We, therefore, assign a TRL of 4 to this method as it has been applied but not very successfully in a few field experiment settings. In the following, we further explore the appropriateness of this TRL assessment for different instrument configurations.

3.3.2.7 Geophone/ hydrophone/ OBS

Both geophones and ocean bottom seismometers (OBS) have been used before for ANI. Cases using hydrophones are relatively rare, although Boullenger et al. (2015) show that the performance of hydrophones is similar to vertical geophone components. Notably, Wang et al. (2019) presented a successful crust imaging near coast study with a 4.5 Hz geophones array. As we expect offshore microseism noises are stronger than onshore, it would be expected that geophones can be successfully used for offshore CO_2 storage imaging. There are also near surface velocity variations measured with 4.5 Hz geophones e.g. Fokker et al. (2021). Since surface wave measurements can retrieve high resolution temporal changes (less than 1%), it might be a good technique to detect CO2 leakage (into shallow subsurface), but has not been tested.

Onshore studies by Cheraghi et al. (2017) and Boullenger et al. (2015), using geophone array to retrieve P wave reflections, which both concluded that image resolution is not high enough for detecting CO2 containment or migration. It could be, however, better for offshore cases with abundant gravity waves (Spica et al. 2020). Another option is deep borehole geophone array, which conducts 1D measurement over the reservoir and/or overburden provides high resolution however limited spatial coverage measurement (Zhou & Paulssen 2020), which might detect CO_2 migration for instance into overburden, but has not been tested before.

The OBS is an ideal tool to measure broadband seismic noises on the sea floor (Schlaphorst et al., 2021). A drawback of OBS is its high cost, which prevents dense spatial coverage and hence produces a less detailed image. Overall, ANI with geophone and OBS are assigned as TRL 4 and 3, respectively.

3.3.2.8 DAS

Compared with previously listed instruments, Distributed Acoustic Sensing (DAS), although routinely used for VSPs, is less used for passive seismics. There is less application of DAS with ambient seismic noise analysis. However, implementation of ANI with DAS has been successfully conducted by Rodríguez Tribaldos et al. (2019) and Spica et al. (2020) whose study is especially relevant as it was in an offshore environment. Similar to borehole geophones, borehole installed DAS can provide along borehole seismic velocity measurement, with much higher spatial resolution (Lellouch et al. 2019). In general, the application of DAS combining ambient seismic noise techniques for CO_2 monitoring is also ranked TRL 3. The potential of increasing TRL with DAS is however higher than the previous instruments, because of its broadband (mHz to kHz) sensitivity, dense spatial coverage, and lower cost of maintenance over long period.

In conclusion, using continuously recorded ambient seismic noise to detect and locate seismic velocity changes due to CO_2 injection, migration, or leakage, we assess the TRL is 3 for DAS and OBS, and 4 for dense geophone array. There are still many tests that can be done, for instance, combining the ambient noise method with active methods, increasing density of array coverage, optimizing DAS gauge length for recording ambient noise, etc. to increase its TRL. There are also questions on the magnitude and scale of leakage and migration, and their related seismic velocity changes. As ambient noise can be seen as an added value of induced seismicity, it is still worth considering in any CO_2 monitoring projects because seismic monitoring and ANI are complementary, which increases the potential of highlighting leakage pathways and imaging the migration of the CO_2 plume, without the need for active sources.

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3.4 Microgravity based methods

3.4.1 Microgravity at the seafloor

Measuring time-lapse microgravity on the seafloor is a geophysical monitoring tool for mapping mass changes in the reservoir during the production of offshore hydrocarbon fields. The technology provides valuable information for reservoir management and is used to constrain the mass balance during production, and better understand the fluid dynamics of the reservoir including communication across faults and reservoir compartmentalization. In this section, a TRA is performed for the technology for monitoring CO_2 injection in offshore storage sites.

This monitoring technology relies on periodical surveys in which relative gravity and pressure are measured at a set of locations at the seabed. Water pressure is used as the starting point of the processing that allows for accurately measuring vertical seafloor deformation (see Section 3.5.1 for TRA on this surveillance technique). The measurement locations are defined by concrete platforms (CPs) that are deployed before the first survey to provide repeatability in the measurement position. During each survey, an instrument frame containing three relative gravimeters and three pressure sensors is sequentially positioned on top of the CPs deployed on the field.

During a survey, each field station is visited at least twice. Each measurement lasts normally for 15 minutes. Halfway into the measurement, quality control is performed onboard the survey vessel. If increased noise levels are identified on the gravity or pressure series, the measurement can be extended by a couple of minutes to ensure excellent data quality. After each measurement, data are immediately transferred to land, where more detailed processing is performed by an onshore team.

To remove the effect of tides from the gravity and pressure data, tide gauges are deployed in the vicinity of a subset of the CPs at the beginning of each survey and retrieved at the end of the survey. After removing tidal effects from the pressure and gravity measurements, all of them are referred to the same reference sea state and can be compared between consecutive surveys.

Several CPs are deployed at a distance from the field rim and are called zero-level stations. They are of key importance to obtain accurate measurements of the changes in relative gravity and pressure, hence subsidence. By using the constraint that no time-lapse signals are to be observed at the zero-level stations, it is possible to remove from the time-lapse differences the contribution of effects not related to reservoir depletion, like different average sea levels or small differences in sensor calibrations in the different surveys.

3.4.1.1 Relationship to other CTEs

For applications in the oil and gas industry, microgravity at the seafloor has proved valuable as a standalone geophysical monitoring technology. At several gas fields at the Norwegian continental shelf, this together with production data is the only surveillance method used for supporting reservoir management (Alnes et al., 2010; Vevatne et al., 2012).

However, there is also value in combining different geophysical monitoring solutions (Lien et al., 2014; Landrø et al., 2017). Field examples where 4D gravity and seismic is used in combination includes two of the largest gas fields offshore Norway: Troll and Ormen Lange. At Troll, the gas-water contact movement was detected with 4D gravity before it could be resolved with seismic (Eiken et al., 2008). At Ormen Lange, gravity monitors aquifer influx together with 4D seismic and allows to increase the time interval between the seismic surveys (Van den Beukel et al., 2014.). In these cases, the integration of gravity and time-lapse seismic reduces uncertainties on aquifer influx and strength. At Ormen Lange, the two technologies are seen to be complementary in terms of enhancing confidence through measuring with independent methods and in the balance between lateral resolution versus cost and timeliness of the results (Vatshelle et al., 2017).

The density of CO_2 is sensitive to pressure and temperature variations in the reservoir (https://webbook.nist.gov/chemistry/). For shallow reservoirs where the CO_2 is close to the supercritical phase, small variations in temperature and pressure can introduce large differences in density. Hence, to convert measured changes in mass to estimates of the CO_2 saturation, temperature and pressure measurements in wells will be important.

Another key factor for CCS monitoring is to determine the fraction of CO_2 dissolved in brine, a process which is not visible in 4D seismic. In (Alnes et al. 2011; Chadwick et al., 2005; Hauge and Kolbjørnsen 2015) information from microgravity in combination with seismic and well data is used to constrain this parameter.

3.4.1.2 Development history and status

The first field application of seafloor gravity offshore for production monitoring was performed in 1998 above the Troll gas field at the Norwegian continental shelf (Eiken et al., 2008).

The motivation was to cover the gap between the available information on the dynamic parameters as acquired from measurements in wells (well pressures and fluid flow rate) and the fluid dynamics across the whole field and in particular the aquifer connections to the south and north of the site.

The acquisition of 4D gravity and seafloor subsidence data was implemented as a less costly alternative to 4D seismic, facilitating more regular 4D repeats with microgravity interleaved with less frequent seismic. Upon comparison with 4D seismic, 4D gravity showed to give a better vertical resolution in the rise of the gas-water contact during production.

From the first survey in 1998 through the repeats in 2002 and 2005, the precision in the 4D gravity data as represented by the measurement repeatability evolved from 26 μGal to 4 μGal.

In 2018, OCTIO introduced gWatch, a new generation of instrumentation for gravity and subsidence measurements. gWatch consists of an instrument frame containing three gravity monitoring units (GMUs) and one temperature-stabilized pressure measurement system (TSP) as shown in Figure 13.

Compared to the gravimeters used in the older-generation equipment, the current gravimeters have fewer recovery effects and largely reduced sensor drift. The TSP contains three Paroscientific Digiquartz pressure sensors in a temperature-stabilised environment. This temperature stabilisation removes the effect of temperature variations at the seabed from the pressure data (Ruiz et al., 2020). The measurement time required to obtain a high-quality gravity measurement has decreased significantly because of the improved instrumentation.

On the operational side, the gWatch equipment has reduced HSE exposure due to the elimination of exposed operations and smaller staff offshore. In addition, gWatch has reduced the overall operation cost due to more efficient surveys and the fact that smaller ROVs and vessels can be utilised for the survey.

In summary, the introduction of gWatch has resulted in improved data quality caused by a combination of the many improvements done when compared to the legacy. A factor of 3 and 1.5 in sensitivities for gravity change and subsidence, respectively, is reported for the Snøhvit field after introducing gWatch (Ruiz, et al., 2020). One µGal is approximately 10-9 g, and this level of sensitivity is two orders of magnitude better than what is obtained from shipborne instruments.

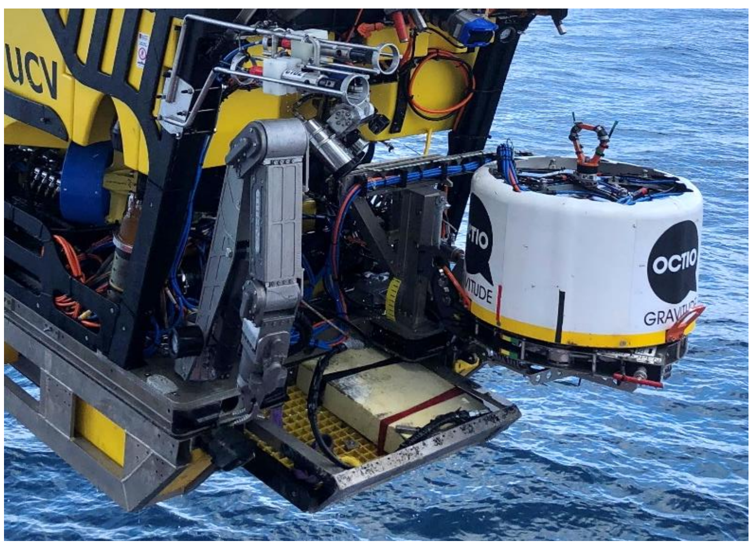

Figure 13: The instrument frame carried by an ROV during an OCTIO survey offshore Norway. The instrument frame is the white cylinder with the OCTIO logo. The instrument frame rests on top of the GMP when transported by the ROV.

3.4.1.3 Relevant parameters inherent to the CTE or the function it performs.

To secure high accuracy in the measurement of time-lapse changes of gravity, it is key to either measure or correct for all temporal variations in the gravity field that is not caused by the injection of CO_2 into the storage site.

Time-lapse consistency is secured by performing the measurements at exactly the same position in each repeat survey. The stability of the CPs is ensured by deploying them in a time before the baseline survey such that they have the time to settle into the sediments before the first measurement is performed. Also, the CP design is tailored to the specific site conditions to minimize any potential disturbances due to currents and scour. Any vertical movement of the CPs due to either seafloor subsidence or uplift is corrected for with deformation data that has millimetre accuracy, for details see Section 3.5.1.

The statistical or random error component in the data is sampled by performing repeat measurements at each of the measurement locations during the survey. The survey is also designed to properly decouple any potentially correlated uncertainty components caused by for example instrumental drift, tides, or changes in the weather conditions during a survey by randomizing the order of the measurements both in time and space.

Changes in the instrumentation, the water column, the atmosphere, or the absolute gravitational field between surveys have the potential to introduce systematic uncertainty in the data. To remove these potential systematic errors, calibration points at a distance outside the field where no injection (or production) induced changes in the 4D gravity are expected are utilized. By imposing the constraint that the 4D gravity signal at these calibration sites is zero, one allows to correct for potential external changes by fitting for an offset and a slope. Moreover, the spread in the 4D gravity at these calibration points after the in-situ calibration provides a direct measure of the accuracy in the time-lapse data. More details on this approach for in-situ calibration are provided in Agersborg et al., 2017.

The spacing between CPs on the seabed is given by the expected lateral resolution with which gravity and subsidence signals can be related to changes in the reservoir. This resolution is in turn mostly determined by the reservoir depth below the seabed (Davis et al., 2008). As a rule of thumb, the spacing between the CPs is given by the reservoir burial depth.

In addition to burial depth, the resolution in the data also depends on the density contrast between the fluids as it exploits the mass redistribution in the reservoir due to fluid flow. For a given density contrast, the resulting mass changes also depend on the flow rates (i.e., permeability) and flow volumes (porosity) of the specific field.

3.4.1.4 Relevant environments

In addition to having been successfully applied on several gas fields offshore, the technology has also been applied at the two CCS sites at the NCS; Sleipner (Alnes et al., 2008; Hauge et al., 2015; Alnes et al., 2011), and Snøhvit (Hansen, O. et al., 2013; Ruiz et al., 2020).

While 4D seismic can accurately delineate the outline of the CO_2 plume, 4D gravity is valuable to quantify the mass changes within the reservoir, the density of the CO_2 plume and thereby the fraction of dissolved CO_2 in brine. The measured gravity signal scales with $1/r^2$ where r is the distance between the receivers and the location of the mass change. Hence, using 4D gravity the depth of the source is the most critical parameter affecting the accuracy at which mass changes can be resolved.

Sleipner, Snøhvit and the planned Langskip (https://ccsnorway.com/a-story-about-the-johansen-formation) storage sites are all initially brine filled aquifers. Hence, the ability to monitor fluid flow depends on the density contrast between injected CO_2 and brine. Other potential storage sites (e.g. Acorn store and Porthos) are depleted gas reservoirs. To date, 4D microgravimetry offshore has not been applied in such storage scenarios. However, if the injected CO_2 either increases the density of the residual gas cap or displaces water in the pore space where aquifer influx has occurred, 4D gravity can potentially be an efficient monitoring tool. Due to being a direct measurement of mass changes in the subsurface, it can be used to quantify the saturation of the CO_2 plume where other surveillance techniques such as 4D seismic can have challenges in discriminating between residual gas already in the reservoir and the injected CO_2.

3.4.1.5 Technology readiness

Microgravity at the seafloor is a mature monitoring technology for quantifying mass changes in the subsurface due to fluid movement with successful applications for monitoring CCS storage offshore. Hence, we assign this technology TRL 9.

3.4.1.6 Estimated cost and time maturing the CTE

While the technology is at TRL 9, new developments have the potential to further enhance the accuracy of the data and reduce operational costs. Several such developments have already been addressed in the DigiMon program. The next phase towards further cost reductions and minimizing the environmental footprint of the technology is to automize the operations where the data acquisition is remotely managed from shore. The developments performed in DigMon are steps towards this end goal, but arriving at such a solution extends beyond the DigiMon project.

3.4.1.7 Expected cost to operate the CTE

The cost of a full 4D gravity survey is a fraction of the cost of a 4D seismic survey. Given the compact instrumentation and the fast turn-around from raw data to fully processed results.

The duration of a survey is field-specific, depending on the number of seafloor stations and the water depths above the survey region. Typical durations span between less than one week to several weeks. With the latest developments in improving the operational efficiency of the methodology, the estimated survey time is less than three weeks also for the largest gas fields at the NCS.

3.4.1.8 References

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3.5 Seafloor deformation sensing methods

In hydrocarbon production or CCS fields, seabed deformation is an observable of reservoir deformation. Hydrocarbon takeout leads to pressure depletion and reservoir compaction. Fluid injection leads to reservoir expansion due to mass and pressure buildup in the pore space. Mapping the corresponding seafloor response provides valuable information on key reservoir properties such as rock compressibility, reservoir compartmentalization, potential reactivation of faults, the evolution of the pressure plume and the dynamics of reservoir fluids.

Hatchell et al. (2017) provide a review of the past, present and future of seafloor deformation monitoring including measurement of horizontal and vertical deformations. Repeated surveillance of seafloor changes can deliver significant business value by helping to reduce reservoir uncertainty and to identify potential geo-hazards as part of a proactive reservoir management philosophy. Here three distinct methods are highlighted:

- Methods that measure relative vertical displacement using seafloor water pressure.
- Methods that measure relative horizontal displacements using acoustic ranging between stations.
- Absolute horizontal positioning using acoustic ranging and GPS.

In this section, the technology of monitoring seafloor deformation by using pressure measurements at the seafloor is covered. Other methods for seafloor deformation monitoring like tiltmeters and DSS are only described briefly.

3.5.1 Pressure measurements at the seafloor

Pressure sensing is the most mature and widely used technique to measure seafloor deformation in deep water environments. Using high precision pressure sensors, subtle changes in relative water depths across the survey region can be measured with mm accuracy providing a 2D map of seafloor deformations across the field.

3.5.1.1 The CTE and its function

Seafloor deformation monitoring using pressure measurements can be carried out in two different operational modes. The deployment of permanent instrumentation at the seafloor provides continuous measurements in time facilitating the discrimination between long-term slow movements and short-term sudden movements such as due to fault slip (Ottemöller et al., 2005; Rinaldi et al., 2013).

Bourne et al. (2009) describe a method for monitoring seafloor subsidence using arrays of Pressure Monitoring Transponders (PMTs) permanently installed on the seafloor that measure pressure every hour for several years. The main advantages of this approach are that continuous data can be acquired and expensive ROV vessels are not needed once the devices are deployed.

However, this method is currently hampered by that pressure sensors have long-term drifts that can be similar to, or even larger than, the subsidence signal (Chiswell and Lukas, 1989; Chadwick et al, 2006; Sasagawa and Zumberge, 2013). Hence, without supplementary data, it will not be possible to separate drift from real vertical deformation.

Alternatively, survey-based techniques can be applied without the use of permanent instrumentation at the seafloor. The technique described in the following was first developed by Eiken et al. (2008), where the relative vertical height differences of fixed seafloor monuments are measured by moving high precision pressure sensors between them. By placing reference monuments at locations inside and outside of the expected deformation small changes in the seafloor elevation can be detected. The estimated measurement error is typically a few mm and rivals the precision of methods used onshore.

In Ruiz et al. (2016) a method for combining the two modes of operation was proposed. Here pressure sensors are deployed at the seafloor for continuous recordings in between surveys, and the time-lapse surveys expand the lateral coverage of the permanent instrumentation and provide a means to correct the continuous pressure data for drift.

In the remainder of this section, the emphasis will be on the survey-based method for measuring seafloor deformation using pressure data.

3.5.1.2 Relationship to other systems

The field-wide survey-based method for measuring seafloor subsidence was initially developed to provide accurate depth corrections when collecting 4D microgravity at the seafloor. Hence, typically, this data is collected as part of a gravimetric survey. For further details on gravimetric surveys, we refer to Section 3.4.1. Today, survey-based seafloor deformation monitoring is provided as a standalone service (Hatchell et al., 2019).

At the core of the technology is the use of high precision pressure sensors. Manufacturers of state-of-the-art pressure sensors quote an absolute accuracy of 0.01% and a resolution of 0.0001% which translates into a 10 cm absolute accuracy and 1 mm resolution at 1000 m water depths. The key is to take advantage of the high resolution of these sensors by removing instrumental (e.g., drift) and environmental factors such as tidal and atmospheric effects from the measurements.

3.5.1.3 Development history and status;

A challenge with standard pressure sensors are their temperature sensitivity; They need time to stabilize after undergoing temperature changes, and calibration equations give a typical accuracy of 0.01% FS (40 cm for a sensor rated for 4000 m). In Ruiz, et al. (2020), a new development to the technology where the pressure sensors are stabilized mechanically and thermally is presented. This development makes the instrumentation insensitivity to temperature changes. Removing the need for stabilization time by having the instrumentation in thermal equilibrium throughout the survey facilitate shorter measurement times. In many cases a few seconds are sufficient. Also, the development removes potential bias in the data caused by uncertainties in temperature calibrations which opens for getting the same accuracy with fewer measurements.

3.5.1.4 Relevant parameters that are inherent to the CTE

Time-lapse repeatability depends on being able to repeat measurements on a fixed location that do not move between surveys. This is typically assured through studying met-ocean data and performing a geotechnical analysis before deploying the concrete platforms. Hence, mitigating actions towards for example possible disturbances due to CP settlement or scouring can be implemented through adjustments to the CP design.

Following linear wave theory, pressure data acquired at water depths above 80 meters are not modulated by pressure changes caused by waves on the surface except under extreme weather conditions. Hence, for typical survey depths, ocean waves do not significantly affect the data quality of the measurements at the seabed.

Tides and other oceanographic induced pressure transients on the other hand have a significant effect on the measured pressure data. To remove these effects, dedicated pressure sensors (called tide gauges) are deployed in the vicinities of a subset of the platforms, during the whole survey. By sampling the pressure transients continuously during the survey at multiple locations spanning the survey area laterally, all pressure measurements can be referred to the same average sea state.

The corrected pressure data are then converted into a measurement of the station depth with a repeatability of a few millimetres (Alnes et al., 2010). The repeatability is obtained from analysing measurements at different visits to the same platform, and it does notably include the effect of uncertainties in the tide corrections. Depth measurements at two vintages are then subtracted to obtain seafloor subsidence with accuracies down to the 3-4 mm, as in the cases of Mikkel and Sleipner (Vevatne et al., 2012, Alnes et al., 2008).

3.5.1.5 Relevant environment

Whole-field subsidence monitoring is a well-proven technology on the Norwegian continental shelf, with many field cases demonstrating both the value of the data and that the accuracy obtained is at the level of a few millimetres (Alnes, H. et al., 2010; Vevatne et al., 2012).

The accuracy in the subsidence data depends mainly on the properties of the water column, the instrumentation, and the survey strategy and is not related to the magnitude of the subsidence/uplift signal. The operational conditions are very much the same for monitoring gas production or CO_2 injection, hence, for the same sampling density, the same accuracies in the subsidence data can be expected independent of the application.

However, in contrast to producing gas fields, large scale CO_2 storage sites may have a wider areal extent which requires some upscaling of the technology. This is feasible without compromising data accuracy. To minimize cost one could envisage an adaptive approach where the active survey area is changing following the different phases of the CO_2 storage site with frequent dense sampling around the wells during the injection face and a more sparse sampling covering a larger area after injection.

The main difference between current applications and CCS lies in the interpretation of the data for model updating and risk mitigation. To fully exploit the value of this source of data emphasis should be on the interpretation of the data.

As demonstrated above, monitoring seafloor deformation using pressure measurements have a long track record of being successfully operated in the full operational environment. Hence we assign TRL level 9 to this technology.

3.5.1.6 Expected cost to operate the CTE in an industry scale environment

As for micro-gravity at the seafloor, the future for minimizing the environmental footprint and operational costs of campaign-style deformation surveys is to tailor the developments towards increasingly automated operations.

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3.5.2 Tiltmeters

Tiltmeter monitoring uses sensitive tiltmeters which continuously measure very small changes in the tilt angle. These instruments can resolve changes in the tilt angle down to ~1 nano-radian (Wright et al., 1998).

With a tiltmeter placed near the earth surface, one can detect the direction of the gravity vector. Where an array of tiltmeters spread over an area provides a data set that can be integrated to obtain elevation changes. Downhole tiltmeters can also be placed in wellbores to determine a precise depth at which compaction or expansion is taking place. Tiltmeters can offer a strain resolution much more precise than geodetic-type measurements (Im et al., 2017).

Surface-deformation measurements with tiltmeters have been used for years in onshore oil fields to monitor production, waterflooding, waste injection, steam flooding, and cyclic steam stimulation (CSS). They have been proved to be a very effective and cost-efficient way to monitor field operations for operators wishing to avoid unwanted surface breeches, casing failures, and excessive subsidence because of production. Near Bakersfield, CA operators have been using tiltmeter-based subsidence monitoring to obtain highly detailed maps of subsidence with continuous data acquisition. The tiltmeter measured subsidence is then correlated to production and injection on a day-by-day basis so the impact of individual injection and production events can be quantified.

Although tiltmeters have been mostly deployed onshore or in boreholes, tiltmeters can also be deployed offshore on the seafloor (Anderson et al., 1997; Tolstoy et al., 1998; Fabian and Villinger, 2007) (Figure 14).

During the lifetime of CCS fields, tiltmeters could be used to:

- Monitor the reservoir deformation (inflation/compaction);
- Monitor the temperature front;
- Monitor the potential reactivation of faults;
- Invert for the reservoir and burden elastic properties.

One of the most important sensor performance indicators is long term stability (drift) and resolution. The linearity is not important as only very small changes in tilt are expected after installation. Unless the sensor has a self-levelling mechanism, a reasonable adjustment range is normally required to ensure that the instrument is within range after seabed installation. The most accurate tilt meters for geophysical monitoring are optical pendulum or bubble inclinometers (Act Sense, D1.1)

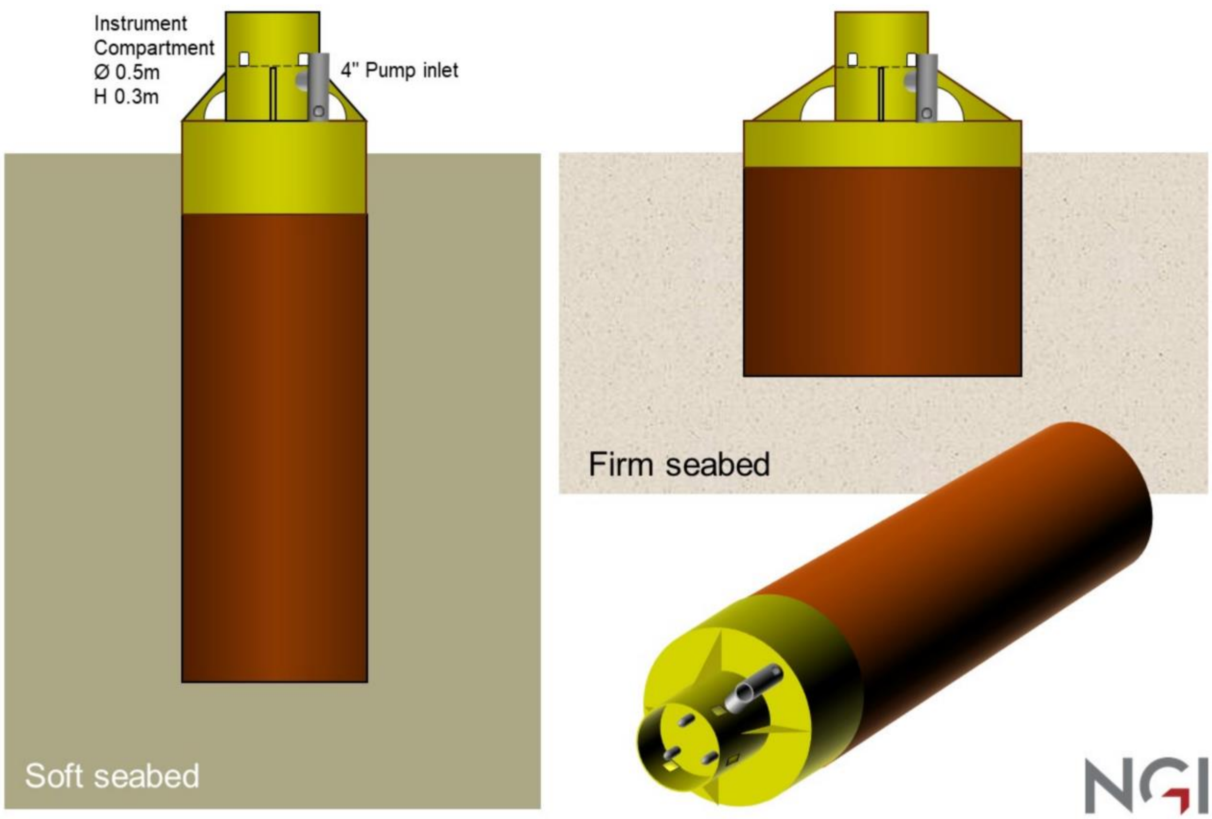

Figure 14. Outlines of a suction anchor and outfitting as proposed by NGI in the ACT-Sense project, the diameter may vary from 1-2 meters and embedment depth from 1-3m, dependent on soil conditions in the field. (ACT Sense, D1.1)

As no documented use of tiltmeters over CCS storage sites has been found we need to classify the TRL of tiltmeters for the monitoring of a large scale CCS site low, TRL 4. But as the use of tiltmeters for surface deformation in other applications has been successful it is expected that large steps in increasing the TRL can easily be made.

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3.5.3 Distributed strain sensing

Distributed Strain Sensing (DSS) is commercially available for monitoring well integrity and has been in use by the oil and gas industry since the 2010s. Using scattered light of certain wavelengths along a fibrefibre optic cable, temperature and strain can be determined along very long distances with high spatial resolution. The scattered signals are sensitive to temperature and/or strain. In the oil and gas industry, it is currently mainly used as a tool for well integrity and measurements along well(path), although DSS has been used to measure ground deformation across long onshore lines and construction projects (slopes, embankments, bridges, dams, railways, pipelines, etc.).

Presently the most common solution for distributed sensing of ground deformation is based on the Brillouin optical time-domain reflectometry or analysis (BOTDR/A) providing distributed measurements of strain along tens of kilometres of conventional optical fibres. If the bending direction or elongation of the cable is known (such as for settlement or subsidence), it is sufficient to record and integrate strain (or fibre elongation) along one fibre in the cable (in addition to temperature compensating recordings) (Act Sense, D1.1).

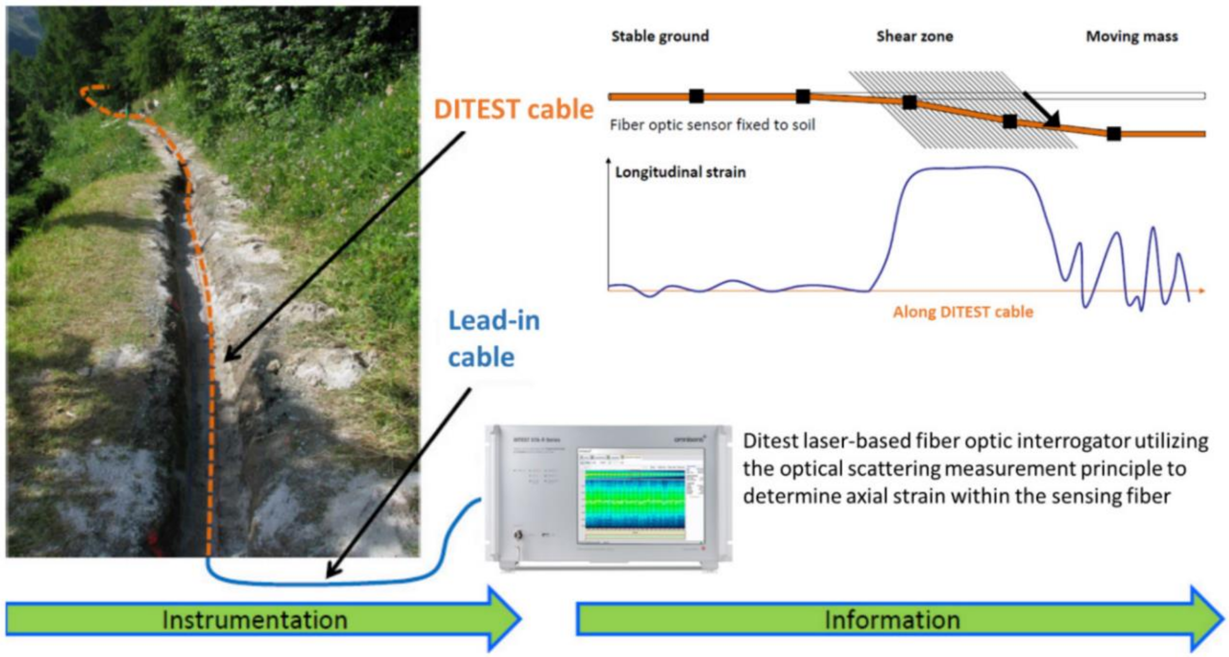

Figure 15. A FO cable used for monitoring ground deformations in this case creep across a slope (Marmota 2012)

Within the ACT Sense project, which focuses on CO_2 storage monitoring using ground surface deformation, DSS along the surface is investigated. One of the tests scheduled (which is severely delayed by the COVID-19 pandemic) is the offshore test in the Bay of Mecklenburg, Germany (Figure 16).

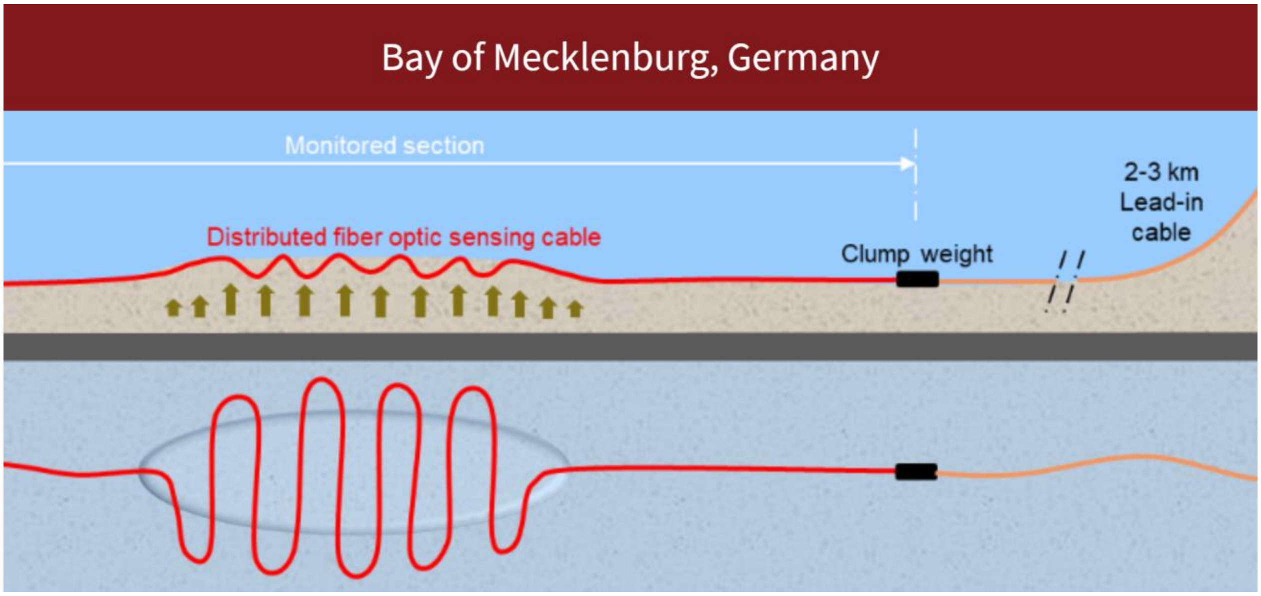

Figure 16. Info graphic on the Mecklenburg test site in Germany (Act Sense, D1.1)

Although DSS is in wide use for monitoring purposes with various applications, there is no documented use of it ever being used in the way as described in Figure 16. Therefore we estimate the TRL level of DSS for the use of monitoring a large scale CCS site low, TRL 4 to 5.

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Marmota 2012, GeoScan Documentation Marmota Engineering AG, consult the website https://www.marmota.com/index.php

3.6 Downhole pressure sensing

3.6.1 Fibre optic borehole pressure sensing

3.6.1.1 The CTE and its function.

Borehole pressure measurements are key for reservoir monitoring. Pressure sensors may also be deployed outside the casing in some cases (often subsea) to provide indications of leaks or pressure buildup. The sensors are installed, either temporarily or permanently in a borehole and often over a range of depths.

Traditional downhole pressure sensors are based on strain or quartz gauges (*Dennis and Zeller*, 1991; *Petrowiki*, 2021). Strain gauges consist of a metal diaphragm that is exposed to the liquid. Pressure changes cause strain which is measured electronically, either with a bridge of resistors or due to varying capacitance over a gap. Quartz gauges depend on the strain sensitivity of quartz which changes the resonance of a quartz oscillator. These sensors are point measurements and data must be telemetered to the surface. These tend to have limited lifetimes due to the effect of the harsh environment on downhole electronics. Other key performance criteria include resolution, transient response, stability, and temperature sensitivity (*Petrowiki*, 2021). One difficulty in data transmission is from electromagnetic signal interference, as data from the sensors must be telemetered to the surface.

3.6.1.2 Relationship to other sensors.

Borehole pressure measurements are essential in understanding the reservoir environment and variations as a result of changing operational ore reservoir parameters. Typically, pressure is measured in coordination with other measurements such as downhole flow rate, fluid density, pressure, and temperature in real-time.

3.6.1.3 Development history and status

Fibre optic pressure sensors fall into two main categories: point sensors and distributed fibre pressure sensors. Point sensors are generally at a higher TRL level and some commercial products exist while distributed fibre pressure sensors, while feasible, are currently at the research level (*Schenato et al*., 2020).

Two basic types of optical point pressure sensors exist, fibre Bragg grating (FBG) and Fabry-Perot (F-P) (*Aref et al*., 2007; *Zhou et al.,* 2019). FBG rely on the effect of pressure on a grating to change the grating response. Advantages are simplicity in frequency multiplexing; disadvantages are sensitivity to temperature as well as pressure and the need for a mechanical component (transducer) to enhance the effect of pressure on the fibre grating. Long-term stability may also be a possible problem. Fabry-Perot sensors use a miniature interferometric cavity to measure changes in cavity length caused by pressure and temperature. These may be intrinsic or extrinsic to the fibre. The manufacture of the F-P sensors is more complicated and typical lifetime of these sensors may be up to 5-10 years or more. Various types of FBG and F-P fibre optic-based pressure sensors are available from commercial vendors.

Distributed fibre optic sensors are more challenging, as pressure has little effect on standard optical fibres (*Schenato et al*., 2020) and large static pressures, as well as changes in pressure are important to measure. Therefore, current approaches depend on pressure-induced strain, pressure-induced birefringence, or pressure-induced attenuation. Pressure-induced strain can be enhanced by special fibres or cabling. A compliant coating applied to the fibre can greatly enhance strain, which may be measured by its effect on either Rayleigh or Brillouin scattering. An alternate approach is to fabricate a special cable that essentially converts pressure into strain on the interior fibres. Pressure also affects the birefringence and therefore will cause changes in polarization (*Li et al*, 2020). Various methods have been proposed to enhance this effect, such as photonic crystals or by changing the chemical composition. Pressure also increases attenuation and this presents another possibility.

One recent innovative approach, which has been tested at the well-scale, combines distributed acoustic sensing and temperature sensing to estimate downhole pressures with a machine learning data fusion technique (*Ekechukkwu and Sharma*, 2021).

Distributed fibre pressure sensors would be extremely useful in monitoring CO2 sequestration, as they would provide high spatial resolution and low-cost sensors and possibly could be combined with other distributed sensors.

3.6.1.4 Relevant parameters that are inherent to the CTE or the function it performs

The pressure information must be accurate and be able to resolve small pressure changes and measure static pressure. The sensors should be functional at high pressures (up to ~200 Mpa) and temperatures (up to 200 C). For long-term CO_2 sequestration, longevity is a key consideration.

Fibre optic pressure sensors possess are immune to electrical inference and robust to environmental conditions, as the electronics are surface-based and only require a modified fibre downhole.

3.6.1.5 Comparison of the relevant environment and the demonstrated environment

Considerable efforts have been made in developing FBG and F-P fibre optic pressure sensors and commercial solutions are available from vendors (Baldwin et al., 2018) or as an example

https://opsens-solutions.com/products/fibre-optic-pressure-sensors/opp-w/.

Distributed pressure sensors appear to have been tested primarily in a laboratory setting although commercial tests of a pressure sensor based on special cable are underway.

3.6.1.6 Expected cost to operate the CTE in an industry scale environment

Fibre optic pressure sensors are point sensors but may be multiplexed on a single fibre optic line. They are therefore compatible with a fibre optic package with multiple sensors. The pressure sensors are point sensors and not distributed; therefore, a limited number of sensors can be deployed in a borehole although in principle can be multiplexed on a single fibre, depending on the sensor design. Distributed sensor cost depends on the implementation and need for any speciality fibres or cables.

3.6.1.7 Technology readiness level Photonic point sensors.

A TRL level of 6 seems reasonable as at least one type of F-P fibre optic pressure sensor is commercially available. It might be possible to assign 7 or perhaps 8, but we lack long-term examples of operation on CO2 rich environments.

Table 5. TRL of photonic point sensors.

Top-level question		Yes/No	If yes, then basis and supporting documentation
TRL 9	Has the actual equipment/process successfully operated in the full operational environment?	Unclear	Not sure whether deployed in CO2 sequestration nor what expected lifetime is.
TRL 8	Has the actual equipment/process successfully operated in a limited operational environment?	No.	

TRL 7	Has the actual equipment/process successfully operated in the relevant operational environment?	No	Not in an operational CO2 sequestration project as far as we are aware.
TRL 6	Has prototypical engineering scale equipment/process testing been demonstrated in a relevant environment; to include testing of safety function?	Yes	Assume oil and gas well is relevant ot CO2 sequestration. Baldwin et al., 2018; see commercial example at https://opsens-solutions.com/products/fibre-optic-pressure-sensors/opp-w/
TRL 5	Has bench-scale equipment/process testing been demonstrated in a relevant environment?	yes	Baldwin et al., 2018; Aref et al., 2007
TRL 4	Has laboratory-scale testing of similar equipment systems been completed in a simulated environment?	Yes	Baldwin et al., 2018; Aref et al., 2007
TRL 3	Has equipment and process analysis and proof of concept been demonstrated in a simulated environment?	Yes	Baldwin et al., 2018; Aref et al., 2007
TRL 2	Has an equipment and process concept been formulated?	Yes	Baldwin et al., 2018; Aref et al., 2007
TRL 1	Have the basic process technology process principles been observed and reported?	Yes	Baldwin et al., 2018; Aref et al., 2007

Distributed pressure sensors.

A TRL level of 5 seems reasonable for at least certain types of distributed fibre optic pressure sensors.

Table 6. TRL of DPS

Top-level question		Yes/No	If yes, then basis and supporting documentation
TRL 9	Has the actual equipment/process successfully operated in the full operational environment?	No	
TRL 8	Has the actual equipment/process successfully operated in a limited operational environment?	No	
TRL 7	Has the actual equipment/process successfully operated in the relevant operational environment?	No	
TRL 6	Has prototypical engineering scale equipment/process testing been demonstrated in a relevant environment; to include testing of safety function?	Maybe	
TRL 5	Has bench-scale equipment/process testing been demonstrated in a relevant environment?	Maybe	
TRL 4	Has laboratory-scale testing of similar equipment systems been completed in a simulated environment?	Yes	

TRL 3	Has equipment and process analysis and proof of concept been demonstrated in a simulated environment?	Yes	
TRL 2	Has an equipment and process concept been formulated?	Yes	
TRL 1	Have the basic process technology process principles been observed and reported?	Yes	

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3.7 Temperature sensing

3.7.1 Distributed temperature sensing

In this section, we review Distributed Temperature Sensing (DTS) for the purpose of well monitoring in the construction and injection phases of a CO_2 injection project.

DTS systems use fibre-optic cables to make high-resolution temperature measurements in-well.

3.7.1.1 Technology and function

A DTS system is an optoelectronic system using optical fibres as a linear sensor to measure a continuous temperature profile. It is the most mature technology in the suite of distributed fibre-optic sensing techniques.

The measurement technique most frequently uses Raman scattering, although some systems use Brillouin or Rayleigh scattering, from an optical fibre and typically measurements are made with a spatial resolution of 1 m and an accuracy of ± 1 °C with a resolution of 0.01 °C. Systems are available to make measurements for distances >30 km and with spatial resolution down to <0.5 m and spatial sampling down to 12.5 cm. Measurements are made on multimode fibres.

3.7.1.2 Interface with other systems

DTS can be used as a standalone solution or in conjunction with the DAS and point sensors. DTS is often deployed alongside DAS because both technologies can make measurements on different fibres in the same cable. This allows temperature and strain/strain-rate measurements to be made simultaneously.

3.7.1.3 Development history and status

The use of fibre-optic sensing in the oil and gas industry has expanded rapidly since the first optical fibre-based pressure sensor was installed in a well in 1993. The industry uses optical fibre sensors to monitor in-well parameters and the technology has been used in an increasing number of applications as technical advances have opened the door for new measurements. Today, fibre-optic sensors are used routinely to measure temperature throughout the wellbore. The use of DTS for environmental monitoring applications has also rapidly expanded over the past few years. Improvements in DTS performance, such as the fine resolution measurement, provide the capability to monitor processes where the scale of interest is much smaller than has traditionally been measured.

The installation requirements can vary significantly between industrial applications. However, DTS has been used for several years in the oil and gas industry for

- Well integrity surveys (Thompson et al., 2015; Buecker and Grosswig, 2017),
- Gas lift monitoring (Hemink and van der Horst, 2018),
- Production, injection and flow monitoring (Williams et al., 2015; Abdelazim, 2012; Lanier et al., 2003; Ouyang and Belanger, 2006; Patterson et al., 2017; Miller and Coleman, 2018),
- Cement integrity monitoring during cementation (Buecker and Grosswig, 2017)

Due to developments in cable technology and materials, measurements can be made in harsh environments. These ruggedized cables can be used in operating environments with temperatures up to 300°C and with pressures above 20,000 psi (Baldwin, 2014).

Cables are deployed in a range of deployment scenarios, cemented behind casing, strapped to production tubing or in production casing via wireline or slickline.

For offshore deployment, a dry tree well configuration or wet connectors can be used in fibre-optic installations.

3.7.1.4 Relevant and demonstrated environments

DTS has been deployed and demonstrated in the field. The measurement of downhole temperature has been identified as a key reservoir surveillance method (Paterson et al., 2011) and DTS has been used for over a decade as a key reservoir surveillance tool alongside other downhole measurements (Freifeld et al., 2014). DTS has several in-well applications relevant to CCS monitoring, namely

- Well integrity surveys to detect tubing leaks and channelling behind casing,
- Injection monitoring (Rangriz Shokri et al., 2019),
- Cement integrity monitoring during cementation (Ricard, 2020),
- Maintain stable injection conditions (Wiese, 2014).

The reservoir and injected CO_2 temperatures are unlikely to be identical and the properties of supercritical CO_2 vary significantly depending on temperature. Therefore, temperature recordings are useful to provide information on the in-situ and local conditions. Several CCS projects have DTS systems installed as part of their monitoring system:

- Injection well at Ketzin, Germany (Hennings, 2010; Wurdemann et al., 2010; Liebscher et al., 2013; Wiese, 2014),
- Monitoring wells at Cranfield, Mississippi, USA (Núñez-López, 2011; Doughty et al., 2013; Butsch et al., 2013),
- Two wells and more than 5 km shallow buried fibre at Otway, Australia (Zhang,2011),
- Injection and monitoring wells at Aquistore, Saskatchewan, Canada (Worth et al., 2014).

Processing of DTS data from the Aquistore CO_2 injection site from both the injection and observation wells indicates dynamic perturbations in subsurface temperature due to injection operations. This ultimately provides a predictive tool to better characterise reservoir behaviour, CO_2 injectivity and the spatial location of the subsurface CO_2 plume (Rangriz Shokri et al., 2019).

Monitoring in a CO_2 enhanced oil recovery (EOR) setting (the Chester 16 pinnacle reef located in Otsego County, Michigan) demonstrates three practical uses of DTS data in a CO_2-injection context (Gupta et al., 2020), namely:

- Warmback analysis is a useful tool for determining where the CO_2 is entering the reservoir from the injection well and can help verify zonal isolation in the wellbore.
- The nature of CO_2 migration vertically along the injection wellbore can be ascertained from the analysis of warmback periods.
- DTS detected the arrival of the CO_2 front at the monitoring well.

DTS data have been useful in identifying the arrival of a CO_2 plume at monitoring wells in an onshore Gulf of Mexico study area (Nunez-Lopez et al., 2014).

Onshore DTS surface deployments are made for environmental monitoring, for example, to measure soil moisture content (e.g., Abesser et al., 2020). Seafloor deployments of DTS are not usually made in industrial settings. However, they are sometimes made for research purposes in oceanographic studies (Sinnett et al., 2020). For CCS monitoring there are not expected to be major DTS surface applications.

3.7.1.5 Technology readiness and outlook

The TRL for DTS is assessed to be 8 since it has been applied to onshore CCS environments but not offshore (Table 7). DTS instrumentation developments continue for offshore applications. Suitable cables for such environments (harsh and high temperature) are available.

Table 7. TRL of DTS

Top-level question		Yes/No	If yes, then basis and supporting documentation
TRL 9	Has the actual equipment/process successfully operated in the full operational environment?	No	No offshore CCS applications
TRL 8	Has the actual equipment/process successfully operated in a limited operational environment?	Yes	CO_2 injection onshore, Rangriz Shokri et al., 2019; Gupta et al., 2020
TRL 7	Has the actual equipment/process successfully operated in the relevant operational environment?	Yes	CCS, Rangriz Shokri et al., 2019; Buecker and Grosswig, 2017
TRL 6	Has prototypical engineering scale equipment/process testing been demonstrated in a relevant environment; to include testing of safety function?	Yes	Since early 2000s. e.g. Lanier et al., 2003; Ouyang and Belanger, 2006; Abdelazim, 2012; Thompson et al., 2015; Williams et al., 2015; Buecker and Grosswig, 2017; Hemink and van der Horst, 2018;
TRL 5	Has bench-scale equipment/process testing been demonstrated in a relevant environment?	Yes	
TRL 4	Has laboratory-scale testing of similar equipment systems been completed in a simulated environment?	Yes	

TRL 3	Has equipment and process analysis and proof of concept been demonstrated in a simulated environment?	Yes	
TRL 2	Has an equipment and process concept been formulated?	Yes	
TRL 1	Have the basic process technology process principles been observed and reported?	Yes	

3.7.1.6 References

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3.8 Chemical sensing based methods

3.8.1 Conventional chemical analysis

Determination of dissolved CO_2 concentration in aqueous solutions plays a crucial role in the long-term commercialization of carbon capture and storage (CCS) that is limited by the perceived risks of long-term CO_2 storage. Wellbore leakage tops the list of these perceived risks. Wells are a direct, engineered path from the CO_2 storage reservoir to the surface, piercing the intervening sub-surface layers. Properly constructed wells provide a virtually impervious barrier to any unintended subsurface transmission. However, damage during well construction or CO_2 injection can allow CO_2 to escape from the reservoir into drinking water aquifers and the atmosphere.

The sensitivity of geochemical monitoring to CO_2 is significantly higher compared to geophysical methods. It allows for very sensitive detection of dissolved CO_2 and upcoming deep saline water. Conventional groundwater monitoring is typically performed by aquifer sampling in a deep well and following analysis in the laboratory, such as high-resolution Mass Spectroscopy, Titrimetric Tests, Colorimetric kits, etc [BP report 2012, https://doi:10.1111/j.1468-8115.2006.00138.x, MONITORING WELL COMPARISON STUDY: An Evaluation of Drect-Push VS Conventional Monitoring Wells (epa.gov)].

Stable carbon isotope analyses of dissolved inorganic carbon can contribute to detection leakage to the overlying aquifer. The leakage could be detected a few months after injection and occurred most probably through the defective annulus of an observation well (Kharaka, (2009) Appl Geochem 24(6):1106–1112). Generally, given the large area of the reservoir and the complexity of the heterogeneous subsurface geology, the employment of conventional sampling techniques is too costly and labour-intensive for CCS scenarios. Additionally, it is site/well and sampling dependent. Each well specific hydrogeology influences the sampling methods [https://doi.org/10.1007/s11053-017-9332-9]. Furthermore, traditional fluid sampling from deep aquifers requires pumping and disposal of formation fluid or wireline equipment such as double ball-lining. Even if the application of a U-tube system (Figure 17, https://doi:10.1029/2005JB003735, https://doi/10.1007/s12665-013-2744-x) requires less equipment and reduced effort but initially higher installation costs. Recommendations are therefore made for well specific evaluations before the adoption of the bailer passive sampling method. This raises the need for an in situ measurement system consisting of distributed sensors capable of collecting temporally and spatially resolved CO2 solubility data. The TRL levels of the geochemical sensors are generally pretty high since the testing is based on established laboratory techniques and relies on validated extraction approaches.

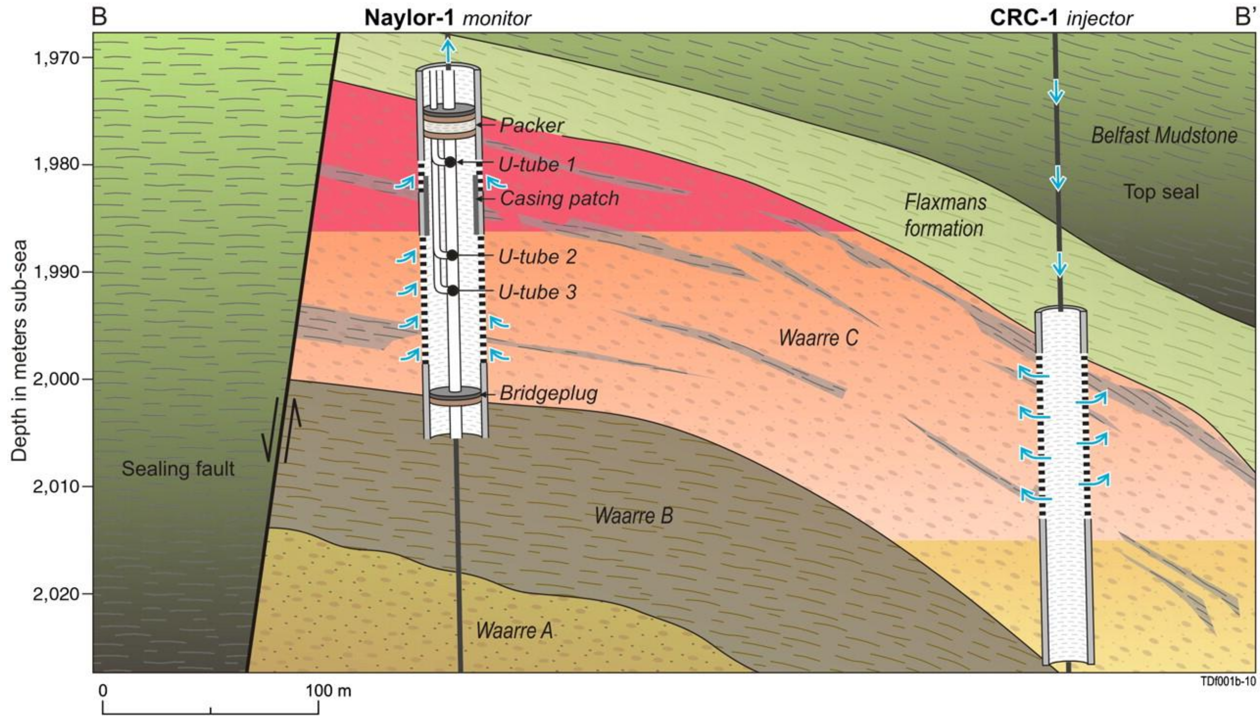

Figure 17. Schematic of an injection and a monitoring well, indicating wellbore perforations and U-tube inlets (Underschultz, 2011)

3.8.2 Distributed chemical sensing

3.8.2.1 Introduction and relation to other CTEs

The ability to ensure the long-term integrity of such wells is vital to ensuring the success of any CCS operation. Therefore, needs exist for robust monitoring at a carbon storage site to detect, locate, and quantify the migration of CO_2 and native storage formation fluids in the subsurface within and above the storage complex main seal. Realizations of distributed monitoring typically fall into one of two categories. In the first category, a large number of point sensors are deployed and connected to form a complex sensor network, while the second category consists of long-length sensors, connected to a readout unit capable of providing analytical information with spatial resolution through the length of the sensor. Associated with the latter method is lower cost and lower complexity, which generally renders it the approach of choice in most applications.

Distributed fibre optic sensor technology has surfaced as an innovative means of monitoring physical parameters in wellbores and other subsurface environments including temperature, pressure, and acoustics. Several fibre-optic monitoring technologies are currently at a high Technology Readiness Level (TRL)and successfully commercialized and field-deployed for a broad range of subsurface measurements including Distributed Temperature Sensing (DTS), Distributed Strain Sensing (DSS), and Distributed Acoustic Sensing (DAS)(Johannes, 2012; Koelman, 2011; Pearce, 2010; Johannessen, 2012; Palit, 2018). Such techniques provide indirect information about subsurface chemistry through integration with advanced physics-based models and machine learning / artificial intelligence methods, but the highest value information can only be obtained through direct chemical sensing technologies.

Distributed Chemical Sensing (DCS) is an alternative fibre optic-based technology holding tremendous promise for subsurface application, but also one that is relatively immature. Current leading DCS approaches integrate functional sensor layers with optical fibres to generate measurable responses to chemical analytes of interest (HIngelrs 2014). Despite promising results in a controlled laboratory environment, inherent technical challenges to field deployment have recently emerged including:

1. Insufficient selectivity to analytes of interest (e.g. CO_2) given complex chemistries of the subsurface.
2. Instability of sensing layer functionalized optical fibres in direct contact with subsurface analytes.
3. Difficulties with scaled manufacturing of sensing layer functionalization techniques with optical fibres.

Accelerated progress of DCS to true field deployment requires alternative sensing modalities which overcome the challenges associated with engineered functional sensor layers via their elimination.

3.8.2.2 Function

DCS using direct spectroscopic analysis can be performed in a distributed manner through near-IR and Raman techniques as enabled by recent patented advances in photonics-based advanced manufacturing and novel optical fibres. More specifically, ultrafast femtosecond laser processing will be combined with engineered hollow-core (photonic crystal) optical fibres for realizing periodic gas-phase access to the hollow core. Limitations of sensing layer based DCS techniques can be overcome as follows:

4. Near-IR and Raman spectroscopy methods provide selective signals to specific chemical analytes.
5. Enhanced stability in the subsurface by eliminating the requirement for thin film-based sensing layers.
6. Reel-to-reel laser processing techniques that are readily scaled to multi-km length scales of optical fibres.

Advantages of the proposed technique include the ability to use fs-based laser processing to optimize the periodicity, physical configuration, and optical characteristics of gas access channels to the optical fibre hollow-core. In addition, the same processing technique can produce additional in-fibre devices (Fibre Bragg Gratings, Fabry Perot Interferometers, etc.) as needed to optimize sensitivity and spatial characteristics of distributed measurements (range, resolution, etc.). The flexible method can even produce multi-parameter functionality such as temperature, strain, and acoustic measurements. Multi-parameter functionality is of unique value in cases where subsurface chemistry is highly sensitive to temperature and pressure, and in cases where both chemical and physical parameters are of interest to inform subsurface modelling and real-time monitoring practices

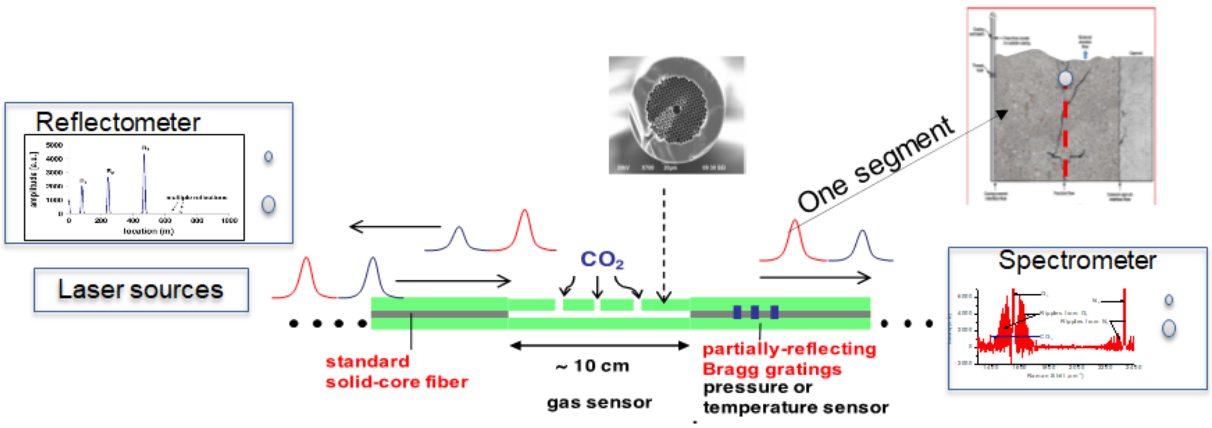

Figure 18. CO_2 detection by spectroscopy in slotted HoF aided by FBGs for multipoint detection

3.8.2.3 Casting of the CTE

There is limited literature on using Raman spectroscopy with photonic crystal fibre to detect CO_2. In Buric et. al. 2008, spontaneous gas-phase Raman scattering using a hollow-core photonic bandgap fibre (HC-PBF) is first reported. In this paper, the gases detected are O_2, N_2 and natural gases such as methane, propane and ethane. Yang, Bond et. al. (2013) achieved detection of 0.04% CO_2 using Raman signal in HC-PBF. In two papers by Hanf et. al. in 2014, CO_2 is detected in a mixture of gases using Raman signal in HC-PBF. They achieved a detection limit of 140ppm using 630nm wavelength and 4ppm using 532nm wavelength. The same group published a review article in 2017. In Chow et. al. 2014, CO_2 is detected as a component gas in human breath analysis using Raman HC-PBF. The detection limit is 45ppm using 800nm wavelength. Alternatively, James et. al. 2015 reported the detection of CO_2 among a gas mixture using Raman signal in a metal-coated hollow fibre. Their detection limit is 140ppm.

For distributed gas sensing, Sumida et.al. 2005 first reported distributed fibre-optic sensing of H_2 gas by coating a H_2-absorptive polymer film on fibre which changes fibre optical response on presence of H_2. Ye et. al. 2009 used multiple segments of fibres joined by gas cells and used frequency shift interferometry to implement multipoint detection of gases including CO_2. In this implementation, the detection points are discrete rather than continuously distributed. Belal et. al. 2014 used IR absorption at 2um in hollow fibre combined with optical time-domain reflectometry (OTDR) that discerns the location of absorption to achieve distributed CO_2 sensing. Garcia-Ruiz et. al. 2017 used photothermal effect due to minute temperature change along optical fibre on the absorption of light by CO_2 and used OTDR to achieve distributed sensing of the temperature change as a way to detect the CO_2 in a distributed way.

Table 8. Overview of chemical sensing technologies, their applications and limitations

	Technologies	Application	Limitations
FO sensing	Fiber Optic OTDR + Brillouin / Raman / Rayleigh scattering (Yamate, *J. Lightw. Technol.*, 2017)	• Distributed temperature, acoustic/vibration sensing	• No gas sensing
FO sensing	Discrete Fiber Bragg Gratings (FBGs) (Liang, *Optik*, 2017), (Baldwin, *Opto-Mech. Fiber Optic Sensors*, 2018)	• Pressure and temperature • Flow velocity	• No gas sensing
Gas sensing	Semiconductor/ capacitive/ catalytic/ electro chemical (Manasa, *Mater. Res. Express*, 2019; Yamazoe, 2003; Ishihara, *J. Electroceramics*, 1998; Azad, *J. Electrochem. Soc.* 1992; Fergus, *Sens. Actuat. B*, 2008; Boudaden, *IEEE Sensors*, 2016; Hoefer, *Sens. Actuat. B*, 1994)	• Gas sensing, including CO_2	• Requires electronics/electrical connections • Often incompatible with harsh environment
Gas sensing	Series of discrete gas cells + interferometry (Ye, *J. Lightw. Technol.*, 2009)	230 ppm acetylene	• Bulky, complex implementation • Incompatible with harsh environment • Very difficult to scale up
FO Gas sensing	Target-species sensitive fiber coating + OTDR (optical time domain reflectometry) (Sumida, *Sens. Actuators B*, 2005)	1% H_2	• Cross-sensitivity to environmental changes • Coating compatibility Issues • Not flexible: specific coating for each specie
FO Gas sensing	Photothermal + OTDR (Garcia-Ruiz, *Opt. Express*, 2017)	100% acetylene @ 0.07 atm. pressure	• Cross-sensitivity to environmental temperature: • Not true distributed sensing
FO Gas sensing	Raman, IR , OTDR (Hanf, *Anal. Chem.*, 2014), (Quintero, *Sensors*, 2018) Belal, *IEEE Photon. Technol.Lett.*, 2014)	4 ppm CO_2; 2% CO_2; Atmospheric CO_2	• Single location point only

In the current inception, the sensitivity/selectivity of Raman/IR is combined with true distributed sensing and scale-up capability of slotted HoFs + multipoint optical detection. IR and/or Raman interrogation in HoFs of several volatiles in small volumes has been previously demonstrated (Yang 2021). Some of the advantages of these fibres are to support larger optical modes and enhance light-matter interactions by several orders of magnitude enabling ppm level of detection as light and chemicals travel in the same medium with increased overlap (Yang 2021). Furthermore, there are also examples of compact NIR systems which can be extended to HoFs gas detection (Chan, 2012). FBGs have also been used for stress/pressure (S/P) and temperature (T) sensor quite frequently by the oil industry: the reflected signal is specific to a wavelength and any S/P/T change will be reported in the wavelength shifts at the reflected output. Herein, they can be used for a complementary function, as S/P/T sensor but also as a temporal detector as the arrival time of the reflected signal is correlated to the distance travelled.

3.8.2.4 Technology readiness

The proposed technology is a novel concept to DCSthat is early-stage, requiring laboratory validation and prototype development as well as initial field validation activities. The proposed project seeks to leverage new photonics based advanced manufacturing methods and unique capabilities for hollow-core optical fibre design and fabrication, to demonstrate initial successes that will be required for further technology maturation. The proposed design in fact enables quasi-distributed chemical sensing.

The current TRL of the proposed technology is estimated at ~3 because the basic spectroscopic techniques, fs-based laser processing methods, and custom hollow-core optical fibres are well-known and demonstrated individually but have not been previously integrated with the optical fibre platform in the context of DCS applications. It is anticipated that there will be substantial innovation and novelty in the optimized on-fibre integration of these individual technology elements such that intellectual property will be developed by the team and a TRL of ~4-5 will be achieved. Because the proposed approach does not suffer from the inherent limitations in scaling and field deployment when compared with conventional sensing layer based DCS technology, it is also anticipated that subsequent follow-on programs will be successful in deployment and ultimately commercialization effort.

Some of the key challenges that will need to be resolved include (1) possible spectral interferences and environmental noise that could mask the signal; (2) low signals and (3) microchannel impairments, (4) greying of the fibres. We will address these challenges by (1) isolating the noise with laser modulation, multivariate analysis methods to help reveal complicated signatures, and spectral filters; (2) evaluate amplification schemes that might be easier with the complimentary NIR technique; (3) replace microchannels with open volume gaps at end of HoF sections to capture signal in transmission and reflection mode (FBG or mirror), (4) additional protection shielding around the opening and periodical photobleaching that is demonstrated to restore the fibre performances.

Table 9. TRL of DCS

Top-level question		Yes/No	If yes, then basis and supporting documentation
TRL 9	Has the actual equipment/process successfully operated in the full operational environment?	no	
TRL 8	Has the actual equipment/process successfully operated in a limited operational environment?	no	
TRL 7	Has the actual equipment/process successfully operated in the relevant operational environment?	no	
TRL 6	Has prototypical engineering scale equipment/process testing been demonstrated in a relevant environment; to include testing of safety function?	no	
TRL 5	Has bench-scale equipment/process testing been demonstrated in a relevant environment?	no	
TRL 4	Has laboratory-scale testing of similar equipment systems been completed in a simulated environment?	Yes	
TRL 3	Has equipment and process analysis and proof of concept been demonstrated in a simulated environment?	Yes	Tested Raman with slotted HoF with CO_2 in Reflection and transmission with FBG
TRL 2	Has an equipment and process concept been formulated?	Yes	Setup in the lab; modeling performed
TRL 1	Have the basic process technology process principles been observed and reported?	Yes	

Scaling to a TRL 4-5 would not require a large investment effort as it would be a natural continuation of existing effort in the laboratory. Extending to TRL6 and up would require a larger use of resources as closer interaction with expert operators in the deployment would be required. The space between CO_2 injection casing and borehole wall is very limited (~ few 10s of mm) making it very challenging for sensor implementation. Nonetheless, fibres have been deployed downhole for DAS or DTS. Also, much of the development depends on the conops, defining where the fibres are allowed to be, either outside the casing with spacers or within the annulus (on-shore cs off-shore CSS systems). We expect to rely on such large expertise to adapt our fibres for distributed chemical sensing, expecting similar costs for deployments.

Having the opportunity to test using observation wells or abandoned wells with no flow potential could be an intermediate step to help us evaluate the validity of cables deployment, their lifetime in more benign conditions and the ability to flush them or replace them, and thus build confidence towards penetrating real injection fields well and operation in more adverse conditions.

Various configurations are being evaluated, that would have different impacts on cost and effort, including:

1. A limited number of HoF detection points at the bottom of the storage well to monitor only the well's capturing capacity with considering failures along the well itself. This would be the most affordable approach but most limited. The cost would reside in the splicing of Hof to solid-core fibres plus armoring and deployment in the well.
2. Interleaved HoF with solid core fibre and FBGs where splicing of the sections is the main shortcoming as it leads to coupling losses. Nevertheless, this can be optimized using standard fibre/telecommunication industry techniques and could be adapted to open access ports for monitoring CO_2 leakage diffusion at specific critical locations or by desired distribution patterns.
3. Only slotted HoF using reel-to-reel fs-laser processing where the advantage is the use of a uniform long fibre. The limitations are in the current lack of such lengths since the fabrication is costly although is possible to develop a process if there is are interested customers, a market or and mission criticality.

The interrogation and detection system would always s be at top of the well and in all cases would have consist of a fixed wavelength laser with 100mWs of power to sustain losses along the well and an optical detector/spectrometer with fine resolution and high sensitivity to read a variation of the signal from farthest points. These systems are available off-the-shelf and can also be combined with other available collection apparatuses

3.8.2.5 Outlook

The short-term goal is to assess commercially available IR/Raman fibres, FBGs, and time-domain reflectivity techniques to detect CO_2 leakage. Holey fibres at 532nm and 785nm will be used first, since they are commercially available and match our Raman laboratory systems (other wavelengths could be exploited if deemed important with the cost of less common equipment and more expensive fibers we will measure the Raman signal at various lengths (up to several meters) to appreciate the diffusion properties in the fibres and effect on performances. NIR spectroscopy systems will be available in parallel at ~1570nm (strongest NIR absorption line of CO_2) for cross-validation. Openings or channels along the holey fibres should ease gas penetration and will be studied to help with the detection if necessary. Once the feasibility has been established with commercial or in-house fibre, we will determine the detection range for CO_2 for specific fibre architectures. The fibers will be also tested in harsh conditions (supercritical CO_2) expecting to discern the signal from water or other gases such as CH_4 since Raman lines are actually fairly separated: CO_2 at 1280cm^{-1}, CH_4 at 2900cm^{-1} at water at 3500cm^{-1} aprt of our studies will We wish to examine the viability of combining HoFs with FBGs if time permits, leveraging tunable lasers, spectrum analyzers and fast detectors readily available in the optics labs. At the end of this work, we will have experimental evidence on the ability of using HoFs for the spectroscopic detection of CO_2 and about their arrangement with fibre Bragg gratings for the signal timestamp retrieval by reflectometry. The evaluation of the loss vs. fibre length will be a critical result, tightly correlated to the allowed limit of detection that can be achieved.

Longer-term plans seek to enable highly sensitive CO_2 detection in the deep subsurface with high selectivity, stability, and sensitivity. More specifically, the goal will be to demonstrate

1. Successful detection of <1% CO_2 in a complex gas mixture representative of subsurface environmental conditions at a length of >1km from the source and detector in a lab environment.
2. Successful demonstration of multi-point measurements of CO2, consisting of at least 5 individual sensor elements spaced no more than 5m apart on a single optical fibre.
3. Repeatability, linearity and grasp of any hysteresis effect to provide a solid reference and confidence in the detection
4. Successful field validation in an observation well first and subsequently a shallow monitoring well for controlled CO2 gas release in the well.

Ultimately, the proposed DCS technology is anticipated to be capable of selective monitoring of CO_2 in complex subsurface conditions at levels <100ppm and multi-km depths with at least 1m spatial resolution. Because near-IR and Raman spectroscopic techniques are being utilized, future research can also enable multi-component speciation, detection, and quantification of additional analytes of interest in subsurface environments through wavelength division multiplexing with multivariate data analytics methods. The proposed technology can be applied to detect, locate, and quantify migration of CO_2 and formation fluids within and above the storage complex main seal through surface deployment within monitoring wells. Given the large dynamic range of detection offered by the Raman approach (can easily tweak applied power or integration time) we could provide a mean of detecting CO2 trapped in hydrocarbons or formation water that would be at much higher levels – up to few mol %

3.8.2.6 References

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4 Discussion

4.1 Overview

We examined and reported on what we regard currently as the most relevant CTEs for developing the low-cost, early-warning, CCS monitoring system of DigiMon, in terms of technologies for field measurements. For the selection, the focus has been on the suitability of CTEs for off-shore use, their suitability when it comes to large-scale CO_2 storage sites, their suitability for application in the near future (hence focusing on technologies with high TRL), and last but not least general affordability. An exception to the focus on methods with high TRL, was the inclusion of several distributed fibre sensing methods still at an initial development phase. These methods are included because we regard them as valuable to explore and develop, and representing monitoring methods with a high potential for providing valuable information with minimal environmental footprint and ability to reduce costs in the near the future.

When ranking the CTEs for use in the DigiMon system, key performance parameters are maturity, applicability, affordability, and also the flexibility of a CTE when it comes to its use as part of an early-warning system for a CO_2 storage site.

Different CTEs can sometimes provide the same type of data or information about the storage operation. This particularly applies in cases where point sensors have a distributed counterpart, e.g. for seismic methods or temperature measurements. Often these CTEs have different sensitivities, accuracies and related costs. Depending on the requirements of the risk analysis a hybrid CTE layout might be one of the appropriate outcomes when designing the monitoring plan.

Table 10 presents an overview of the reviewed applications and CTEs together with the resulting TRLs.

Table 10. CTE and TRL overview.

Application	Class	CTE	TRL	Note
Surface and seabed reflection methods	Seismic reflection surveys	Conventional hydrophone of in case of OBN multi component sensors	9	Mature technology
		DAS	5-6	Recent experiments show good potential
Borehole seismic methods	VSP	Conventional VSP	9	Mature technology
		DAS-VSP	8	Good results only used onshore sofar
	Crosshole tomography	Conventional sensors (Novel SV source)	5-6	In testing phase at different environments
Passive seismic methods	Microseismics	Geophone/hydrophones	9	Mature technology
		DAS	7-8	Operational but not applied
	Ambient Noise Interferometry	Geophone/hydrophones	4-5	
		DAS	4-5	
Microgravity	Microgravity at the seafloor	Point-based, mobile, microgravity sensors	9	Mature technology
Seafloor deformation	Measurements at the seafloor	Pressure sensors	9	Mature technology
		Tiltmeters	4	Good results, only used for other applications sofar
		DSS	4-5	Good results, only used for other applications sofar
Downhole Pressure sensing	Measurements in well	Conventional pressure sensors	8-9	Commercially available but lack long term use in CCS
		DPS	5-6	
Temperature sensing		DTS	9	Mature technology
Chemical sensing		Conventional sensors	9	Mature technology
		DCS	3	

4.2 Application

For large-scale, industrial CCS operations, monitoring plans and their related activities are expected to be designed around risks. These risks should have been identified by extensive risk assessment workflows. The goal of monitoring activities will be to keep risks at an acceptable level so operations can continue in a safe and cost-efficient manner.

Depending on the type of risk and the type and characteristics of the storage site, certain monitoring applications might be required. For example; When during CO_2 injection into a saline aquifer, fault reactivation of a known fault, away from a well is deemed a risk, microgravity or seafloor deformation monitoring could be used to indicate movement of fluids or buildup of pressure near that fault. Or, if a higher resolution of the CO_2 plume would be required, (time-lapse) seismic surveys could be used. Or, microseismics could be used to measure an increase of (low intensity) seismicity over the fault. Any threshold in required resolution and uncertainties should be determined in the risk assessment and analysis studies. These requirements should then be translated into the appropriate monitoring approach.

For any immediate industrial storage applications, the CTEs with a high TRL score can become part of the monitoring plan. E.g. seismic methods, mainly making use of conventional sensors, microgravity, DTS, etc. But also CTEs which are not yet at TRL 8 or 9 might be included, e.g. as a supporting technology to a mature CTEor to facilitate further development of the technology if results in other applications are promising.

When designing an optimized setup to monitor the development of a certain risk, there is also the possibility to combine monitoring data from various CTEs in inversion workflows. A workflow making use of data from multiple CTEs could outperform the capability of a single CTE by providing independent measurements of the same processes or illuminating multiple processes simultaneously. A TRA of various types of combinations of data streams and workflows is not covered in this report. However, this report will serve as a valuable tool in the continued work within DigiMon for integrating the different CTEs into the overall DigiMon monitoring system.

4.3 Current and future work in DigiMon

Within DigiMon, improvements on the individual CTEs covered in this TRA is obtained through developments in instrumentalization, software and processing techniques. Through these efforts, the applicability of the technologies is sought to be improved either by enhancing the accuracy and sensitivity of the methods or implementing measures to improve the operational efficiency and reduce acquisition costs. The outcome of the work on the individual system components is included in this TRA. A dedicated summary of the specific developments within DigiMon will be provided in a report (D1.11 Project report on WP1 outcomes relevant to other WPs).

For system integration, the (inversion) results will be analyzed with dedicated uncertainty quantification of the system components alone and in combination, also considering information obtained from WP1 (D1.11), this TRA (task 2.3) and the SEL analyses (WP 3).

Sensitivity studies and uncertainty quantification of CTEs and the inversion of their data streams are underway (tasks 2.4 and task 2.6). Data from field experiments and synthetic data of the Smeahea site are extensively used in these studies. This work also includes further development of seismic methods by combining data from conventional seismic sensors with DAS measurements and the development of techniques like cross-hole tomography

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Appendix

5.1 CTE description template

Template for use of CTE describtions (in chapter 3, after DOE G 413.3-4A9-15-2011)

INTRODUCTION

Technology Reviewed

Provide a detailed description of the technology that was assessed.

TRA Process

Provide an overview of the approach used to conduct the TRA. Reference applicable planning documents.

RESULTS

Provide the following for each CTE assessed:

Function

Describe the CTE and its function.

Relationship to Other Systems

Describe how the CTE interfaces with other systems.

Development History and Status

Summarize pertinent development activities that have occurred to date on the CTE.

Relevant Environment

Describe relevant parameters inherent to the CTE or the function it performs.

Comparison of the Relevant Environment and the Demonstrated Environment

Describe differences and similarities between the environment in which the CTE has been tested and the intended environment when fully operational.

Technology Readiness Level Determination

State the TRL determined for the CTE and provide the justification for the TRL. Using the template for TRL table (after Technology Readiness Assessment (TRA)/Technology Maturation Plan (TMP) Process Implementation Guide, Revision 1, U.S. Department of Energy Office of Environmental Management, Washington, D.C., August 2013) as below.

Table 11. Template for TRL table.

Top-level question		Yes/No	If yes, then basis and supporting documentation
TRL 9	Has the actual equipment/process successfully operated in the full operational environment?		
TRL 8	Has the actual equipment/process successfully operated in a limited operational environment?		
TRL 7	Has the actual equipment/process successfully operated in the relevant operational environment?		
TRL 6	Has prototypical engineering scale equipment/process testing been demonstrated in a relevant environment; to include testing of safety function?		
TRL 5	Has bench-scale equipment/process testing been demonstrated in a relevant environment?		
TRL 4	Has laboratory-scale testing of similar equipment systems been completed in a simulated environment?		
TRL 3	Has equipment and process analysis and proof of concept been demonstrated in a simulated environment?		
TRL 2	Has an equipment and process concept been formulated?		
TRL 1	Have the basic process technology process principles been observed and reported?		

Estimated Cost/Schedule

State the estimated cost and time requirements, with associate uncertainties, and programmatic risks associated with maturing each technology to the required readiness level.

Expected cost to operate the CTE in an industry scale environment (This does not come from DOE G 413.3-4A9-15-2011, it was added specifically for this TRA)