The Importance of Geophysics and Seismic Analysis in CCUS Projects

Introduction

Whilst the concept of CCUS and the various different technologies implemented in its application are not new, the large scale application is in its infancy. The ability to confidently monitor the injected CO_2 in the subsurface is critical for both project integrity and the acceptance of the process in the general public, this is where the application of geophysics is likely to have a key role, along with other technologies.

Carbon Capture, Utilisation and Storage (CCUS) projects are envisaged to be a major part of the solution to meeting the 1.5 to 2.0°C temperature increase limits agreed at the Paris COP 21 meeting, and reaffirmed in Glasgow at COP 26. Through long-term, subsurface storage, the volume of carbon dioxide (CO_2) released into the atmosphere, from power generation and industrial processes can be dramatically reduced [1]. The use of CCUS is expected to be temporary, to be used during the transition, away from the use of fossil fuels towards renewable energy sources. CCUS can also be used to enable the clean production of hydrogen (blue hydrogen), which is likely to be a major source of energy within the next few decades.

The underground storage of CO_2 is not a new concept and the process of injection of CO_2 into the subsurface has been used by the oil and gas industry for several decades, albeit on a relatively small scale [2] and [1]. An example of this is utilization of CO_2 injection into a subsurface hydrocarbon reservoir for Enhanced Oil Recovery (EOR) processes, whereby injected CO_2 is used to lower oil viscosity and sweep hydrocarbons towards production wells. During this operation some of the injected CO_2 does not return to the wellbore and therefore remains trapped in the reservoir. However, when CO_2 is used for EOR purposes this would typically be considered under the Utilisation category of CCUS as opposed to Storage, particularly when the source of the CO_2 is field operations. However, there have also been a number of pilot CCUS projects, mostly in North America and a much smaller number of enterprise CCUS projects dedicated to storage of externally sourced CO_2, which would more reasonably fall under the Storage category.

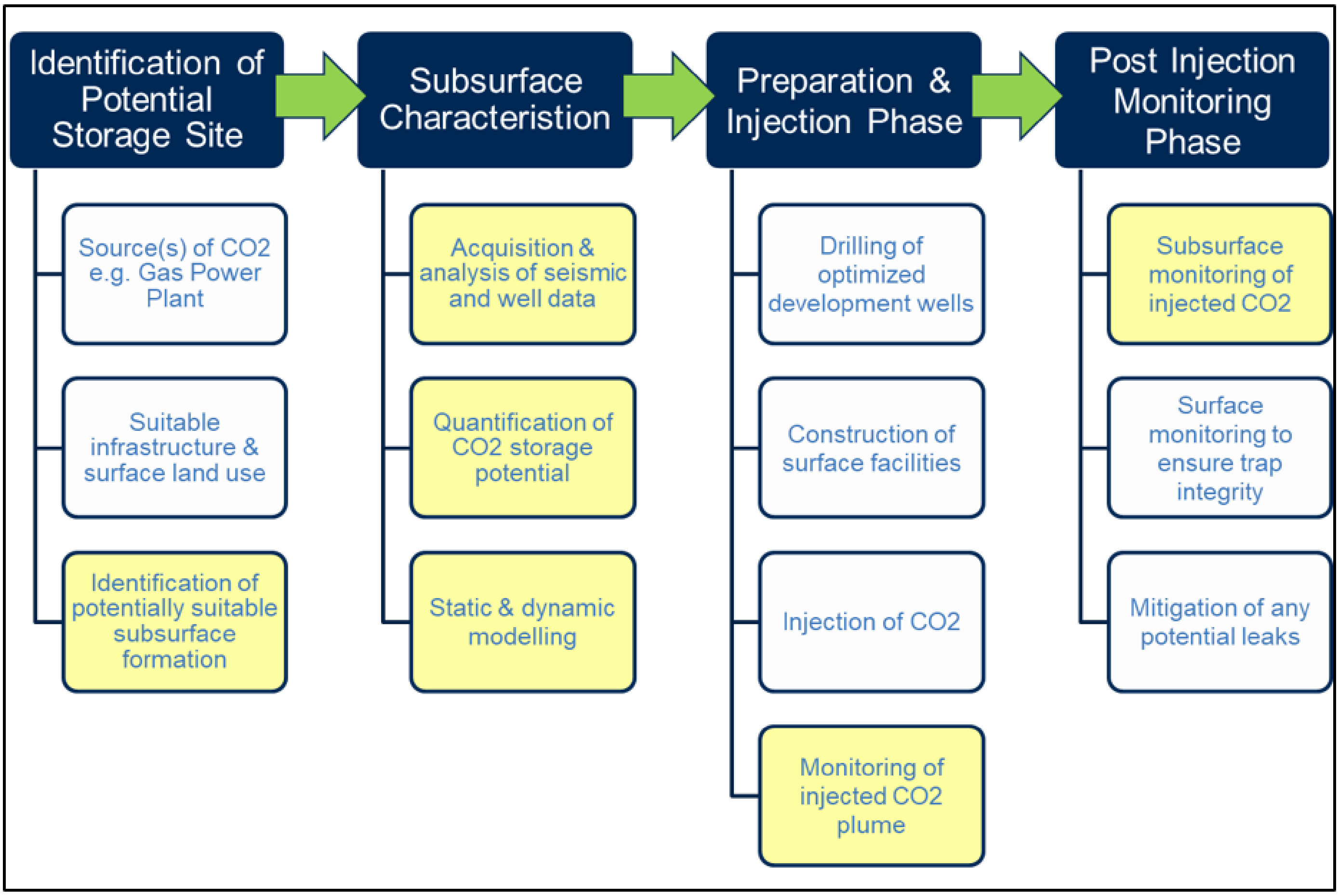
CCUS (or more appropriately CCS) projects can be broadly sub divided into three main categories, the first involves storage in a depleted hydrocarbon field, the second uses saline aquifers and the third salt caverns. The CO_2 storage capacity of depleted hydrocarbon fields is limited by the size of the trap associated with the original hydrocarbon field. However, the ultimate potential CO_2 storage capacity of other CCS projects is much larger, especially where saline aquifers are the storage target.

In order for meaningful scales of CCS to be achieved, saline aquifers will have to be utilised, in addition to depleted hydrocarbon fields. There are additional considerations concerning the different subsurface storage types. Saline aquifer reservoirs are likely to have a much lower efficiency factor (up to 6%, but more generally approximately 2%) by area compared to a depleted gas field, but can cover a much larger area and volume in the subsurface. Depth is also a very important consideration of CO_2 storage. The phase behaviour of CO_2 is important, as over certain depth, pressure and temperature ranges, CO_2 can be stored in a dense phase rather than gaseous phase, permitting up to four times the storage volume of gas given the same pore space in the subsurface. These densities tend to equate to relatively shallow depths in the subsurface (1,000 to 3,000 m).

The Potential Role of Geophysics in a CCS Project Life-Cycle

To understand the potential roles of geophysics in CCS and CCUS projects, it is important to consider the entire life cycle of such projects. Figure 1 shows the typical life-cycle of a CCS project where the aspects that may require some geophysical input are coloured yellow.

Figure 1: Typical Life-Cycle of a CCS Project



Source: GaffneyCline

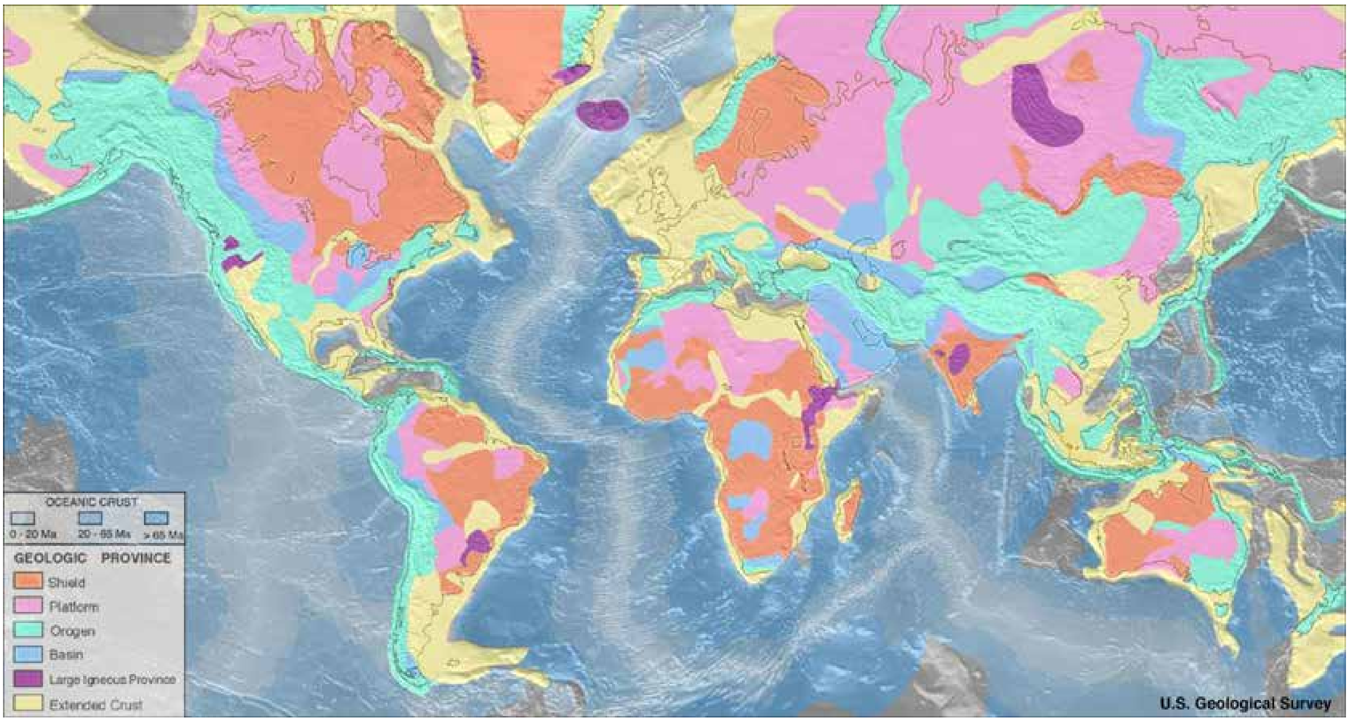
There are primary roles for geophysics during most stages of the project cycle [2]. The focus here is intentionally the uses of seismic data, but there are also likely to be roles for other geophysical tools and processes including gravity, satellite and tilt meter data. The latter are considerably cheaper relative to seismic data and may be used in areas where seismic data cannot be acquired, or where the dataset is very challenging due to surface or subsurface conditions. It is likely these types of dataset may be complementary rather than an alternative to seismic. A brief review of the project life-cycle shows that there are roles for several geoscience disciplines, not just geophysics, as well as reservoir engineering, facilities engineering and economic analysis.

The acquisition and analysis of seismic data is going to be key in characterising the nature and structure of the reservoir and estimating potential storage volumes. It is important to note that CCS projects using depleted hydrocarbon fields are highly likely to already be sufficiently characterised with well and seismic data prior to the injection of CO_2. Therefore, the initial identification and characterisation stages associated with saline aquifers or salt caverns are very different from those that are depleted hydrocarbon fields. There are numerous areas of the world that are associated with very mature hydrocarbon provinces such as the North Sea, which already has near blanket coverage of 3D seismic data. Whereas other areas globally have relatively sparse existing seismic datasets. It may prove however that even in areas with dense coverage of 3D seismic data, seismic reprocessing may be required, in order to optimise the data for the target interval, particularly if the CCUS target interval is located at a different depth to the hydrocarbon-bearing reservoirs.

Subsurface Characterisation of CO_2 Storage Formations

In order to inject CO_2 into the subsurface, a porous and permeable lithology is required. These are the same requirement as a hydrocarbon bearing reservoir, in order for the oil or gas to flow towards production wells. The vast majority of the world's sedimentary basins , which are likely to be dominant in CO_2 storage, have been identified and delineated to some extent (Figure 2) and so the focus is likely to be selecting optimal storage locations, within already identified and established sedimentary basins and in proximity to a source of CO_2.

Figure 2: Distribution of Geological Provinces



Source: USGS – https://earthquake.usgs.gov/data/crust/maps.php archived version https://web.archive.org/web/20150203073142/https://earthquake.usgs.gov/data/crust/maps.php

The application of geophysics in the characterisation of the subsurface for use in the storage of CO_2 is very similar to methods used in traditional oil and gas fields. The primary use of seismic data has historically been in the delineation of the subsurface and establishing the nature, shape and size of the trapping structure. The methods and processes used in these workflows are very well established and can be directly employed in the subsurface characterisation of CO_2 storage locations.

Historically, it was only possible to have high confidence in the reservoir quality at well locations and the geological variation between the wells could only be estimated. However, where the seismic response can be calibrated to some feature of the reservoir such as porosity, saturation or net to gross at the wells, it is sometimes possible to predict the lateral variability of the reservoir between and away from wells in the field area.

This can also be true of the fluid type. Under certain reservoir conditions it is possible to predict where gas, oil or brine are located within the subsurface. It should be noted that it is only possible to be confident in this interpretation with calibration to well control and in certain geological conditions. Without well control there are numerous artefacts that can mislead the interpreter. Typically, greater volumes and higher qualities of data tend to result in higher confidence interpretations.

Therefore, in order to characterise a CO_2 storage location with confidence, numerous wells and 3D seismic data are required as a minimum. Where existing and depleted oil and gas fields are to be re purposed as CO_2 storage locations, it is highly likely that seismic and well data already exists. However, with newly identified potential storage locations wells and seismic data will have to be acquired, processed and analysed.

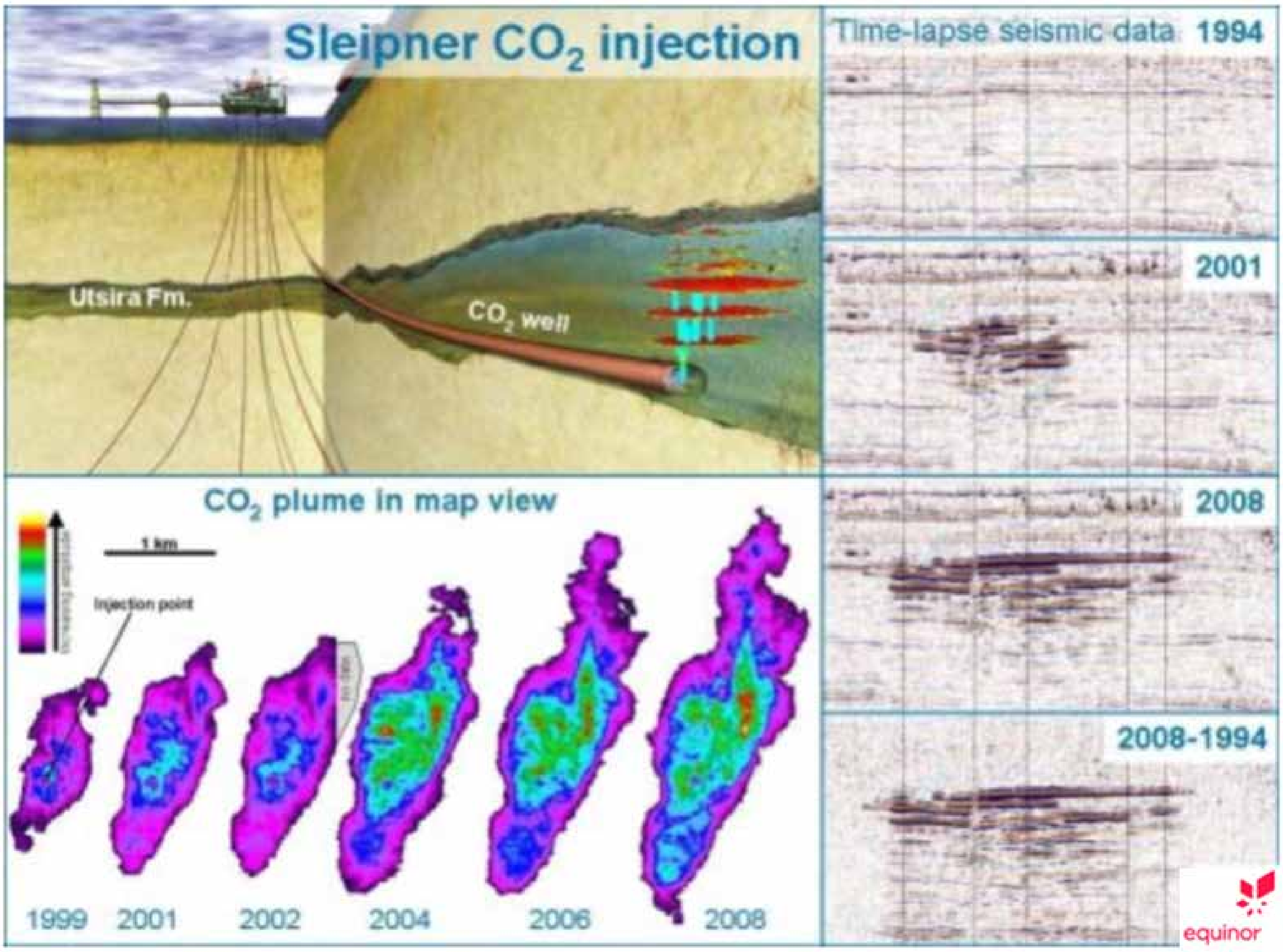
Monitoring of CO_2 in the Subsurface During Injection Phase

A key part of any CO_2 injection project will be the ability to monitor the movement and ultimately the final location of the CO_2 plume in the subsurface. There are several reasons why this is important. It needs to be ensured that firstly, the CO_2 is being injected into the intended formations, secondly, the CO_2 is not leaking into other geological formations, along faults or through well bores and thirdly, the potential storage capacity of the reservoir is optimised.

The acquisition and interpretation of seismic data is likely to have a key role in the monitoring of the injected CO_2. Over the last 10 to 15 years the application of 4D seismic data has been used to an increasing extent in the monitoring of production from oil and gas fields. In this application comparison of multiple 3D or 'monitor' surveys acquired over the life of the field and compared to an initial 'baseline' survey allowing the movement of different reservoir fluids to be modelled as hydrocarbon production progresses. For this to be reliable, it is essential to have well control to calibrate any responses, but it is possible to use a 4D seismic dataset to see how the production of hydrocarbons or the injection of water has progressed over the life of the field. 4D seismic data are often also used to identify un-swept areas, which are areas where hydrocarbons have not yet been produced. Areas that have been swept of hydrocarbons would show differences to a baseline survey because the fluids within them have changed e.g. from gas to water, whereas un-swept areas on the monitor survey would remain very similar to the baseline survey.

The application of 4D seismic technology to monitoring the injection of CO_2 is very similar. The injection of CO_2 into a formation would likely change the petro-elastic properties of the reservoir sufficiently to be measureable on a 4D dataset, when compared to a baseline survey because the fluid will have changed. For example, a change from pore space filled with saline water to CO_2 is associated with a reduction in density. Interpretation of the data could show where the CO_2 has been injected and if it had remained within the intended formation. Figure 3 shows an example of the use 4D seismic data for monitoring the injection of CO_2 at the Sleipner Field from 1994 to 2008 [3]. It must be noted however that whilst similar some additional considerations may be required for monitoring CO_2 injection, such as distinguishing between CO_2 as a gas phase and CO_2 in a super critical state, which by nature is closer in density to other reservoir fluids such as saline water and oil.

Figure 3: Observation of CO_2 Injection at the Sleipner Field



Source: [3]. Thanks to Equinor for permission to use the illustration and seismic images. The 1994 image shows the pre-injection baseline survey and the 2008 survey is an example of a monitor survey acquired 14 years after injection began. The amplitude maps show how the injected CO_2 plume has evolved over time.

Typical 3D and 4D seismic acquisition (such as at Sleipner) involves very dense datasets. In 2016 and 2017 a feasibility study was conducted, which used a sparse, semi-permanent seismic array of 96 nodes to monitor the extent of CO_2 injection at the Bell Creek oil field located in Montana, USA. The proof of concept study was conducted by the Energy & Environmental Research Center (EERC) [4]. Typically 3D and 4D surveys are acquired using multiple intersecting lines of receiver arrays resulting in many thousands of data points which are processed to result in a 3D cube of seismic data. In this study, 96 receiver nodes were installed in fixed positions, at variable spacing over the field area and a single weight drop source was installed in the center of the array. Each shot resulted in point data at each receiver location. Data were acquired on a weekly basis from each receiver and the results from 26 locations were studied in detail. The results were compared to simulation models and a 2D seismic line for verification. Overall the results were mixed. Some nodes gave very similar results to those expected from the simulation model, whereas a smaller number gave false positive or false negative results. The main issues of the study were that incoherent and cultural noise was an issue but was mitigated by processing and changes to the acquisition method. Further refinements to the method and supplemented with other data types this approach may provide a very cost effective way to monitor injected CO_2 in the subsurface. The main benefit of this approach is that data could be acquired, processed and analysed much more frequently than a full 4D dataset. This would allow a higher frequency understanding of CO_2 migration in the subsurface. However, the resolution of the data is much lower as it is a point dataset, compared to a spatially continuous 4D dataset.

During 2014 and 2015 the U.S. Department of Energy funded a project near Citronelle, Alabama to test the application of downhole geophone arrays using fibre optic cables, alongside other non-geophysical techniques such as leak detection through temperature sensing [5]. The results of the study showed that optical fibres used for distributed acoustic sensing (DAS) resulted in a high resolution VSP image which surpassed the quality of more traditional VSP acquisition methods. In addition, time lapse acquisition of the VSP using the new technique was successful for monitoring CO_2 and could potentially be used in both the injection and post-injection monitoring phases of a CO_2 storage project. The project also investigated cross-well seismic surveys using the same fibre optic technique, but these were not successful due to high field and cultural noise levels, which acted to mask any response arising from the injection CO_2 [5]. The lessons learnt from this study included information regarding the optimal times to acquire this type of data to maximise the chances of useful datasets.

DAS was also used for monitoring injected CO_2 in a pilot CO_2 storage scheme located in Saskatchewan, Canada called 'Aquistore' [6]. In this study, several different variations of the technique were used to acquire 2D and 3D VSP data in order to compare different acquisition techniques, and comparisons were also made to traditional acquisition techniques. The results showed that DAS data resulted in improved signal to noise over some traditional acquisition methods and that DAS data can be used for monitoring of injected CO_2 using time-lapse acquisition. Furthermore, 2D and 3D VSPs can be used for CO_2 monitoring in the subsurface [6]. The results of these studies are encouraging as it adds to the tool kit available for CO_2 monitoring, during both the injection and long term storage and monitoring phases. The acquisition, processing and analysis of 2D and 3D VSP datasets is likely to be significantly cheaper than 4D seismic datasets, but this will be balanced by the acquisition costs of wells which varies depending on the local conditions. Although cost considerations are important economic factors, the use of 4D data is one of the technologies that may help with societal acceptance of the concept of CCS, at least in the early stages of implementation.

It is also possible to monitor CO_2 injection with equipment in wells, such as pressure gauges. This approach is feasible in depleted oil and gas fields with a large numbers of existing wells. However, the cost of drilling numerous wells for the purposes of monitoring CO_2 may be prohibitive, depending on the surface conditions and depth of the target formation. In other areas the costs of drilling numerous wells will be considerably cheaper than the costs of acquiring 3D or 4D seismic data. This will have to be considered during the early planning stages of a potential project.

Monitoring subsurface pressures during the injection phase will be a critical part of the injection process. Geomechanical studies will be required prior to injection of CO_2 in order to estimate the pressures at which fracturing may occur, or reactivate any existing pre-faults. Ensuring that faults and fractures are not re activated will be a key part of ensuring the trap integrity is not compromised. Seismic data can be used under certain conditions to infer pressure variation in the subsurface, but down-hole pressure gauges in wells will give the most accurate readings. However, this data will provide sparse sampling compared to seismic data, so will likely be used in conjunction.

Passive seismic, also known as microseismic may have applications in the monitoring of injected CO_2. Microseismic events such as the creation or re activation of faults and fractures, which are induced by pressure changes associated with the injection of CO_2 can be recorded by permanent sensors. Given an adequate number of sensors over a wide enough area of the reservoir and sufficient detection precision, this technique can potentially provide an understanding of CO_2 plume movement in the subsurface. As a consequence of the number of sensors required, this technique may be more suited to depleted hydrocarbon fields or where CO_2 injection is being used as an EOR tool.

The acquisition, processing and analysis of well and seismic data are typically associated with relatively high costs and these will have to be factored into any potential projects. There are some tools that are typically much cheaper and may still be able to provide reasonably high resolution data. Geo-spatial satellite data and tiltmeters now offer sufficient resolution to detect surface elevation changes of 1 to 3 mm which occur in response to injected fluids, in both onshore and offshore environments. These methods are not widely used at the moment for monitoring of injected fluids but there are a few examples of successful implementation, such as at the In Salah Field, Algeria. Increases in surface elevation would indicate areas where CO_2 has been injected and subsidence indicates areas of fluid withdrawal.

It is possible that gravity data may also be useful. Where CO_2 replaces brine, the density of the column of rock would be reduced. The limitations of the gravity method are the resolution and depth of investigation. It is unlikely that significant density variation would be observed upon gravity data where porosity of the reservoir is below 10% or less than 10 m in thickness. Furthermore, a reservoir at a depth greater than 2,500 m, is also unlikely to yield a gravity response.

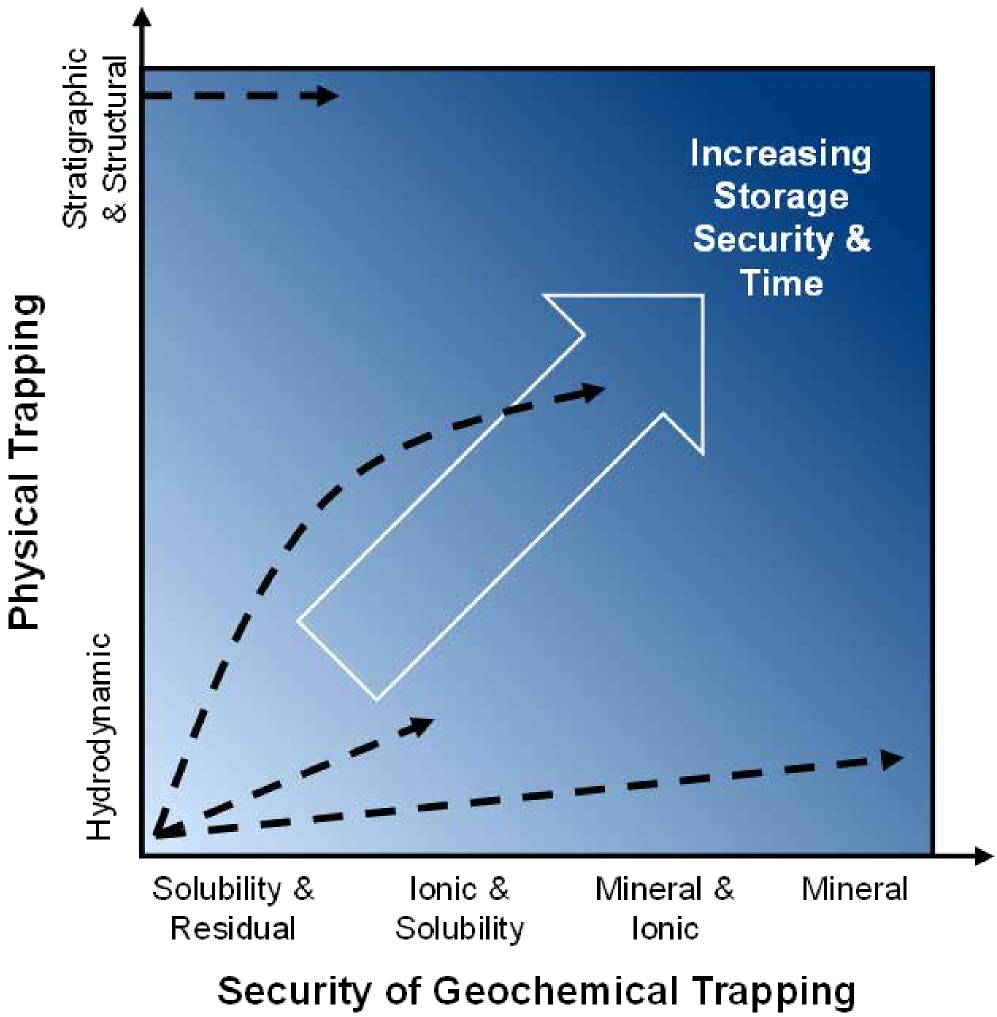
Satellite elevation, tiltmeter and gravity data are unlikely to be standalone methods of observation as they do not provide the high resolution possible with 4D seismic data or direct measurement capabilities of wells, but may be suitable, lower cost, supplementary datasets.

Storage of CO_2 During the Post-Injection Phase

After the injection phase is complete, CO_2 storage projects will enter the post-injection / monitoring phase. During this time, no further CO_2 will be injected, but it will be important to understand the location of the injected CO_2, at least in the short term to ensure trap integrity. With the cessation of CO_2 injection, there are unlikely to be rapid pressure changes within the reservoir and so the potential for fault reactivation or fracturing is much less likely than during the injection phase.

In the early stages of CO_2 storage, the trapping mechanism is typically physical i.e. the CO_2 is trapped below low permeability seals by buoyancy, in the same way that hydrocarbons are trapped. Over time other mechanisms will act to stabilise the CO_2 [2]. Solubility trapping occurs where the CO_2 dissolves in formation water and over longer periods some fraction (potentially all) of the CO_2 will be converted to stable carbonate minerals (mineral trapping). These non-physical (or Geochemical) forms of CO_2 trapping and storage are very low risk because the CO_2 cannot escape to the surface under buoyancy [2], but it may take thousands of years for a significant portion of the CO_2 to be converted, depending on subsurface conditions and injected volumes (Figure 4).

Figure 4: Evolution of Storage Security Following Injection of CO_2



Note: Dashed lines represent examples of different storage security pathways from physical to geochemical.

The acquisition of an additional 4D seismic monitor survey immediately post-injection is likely to be useful during the very early stages of this phase as they could be used to track any additional subtle movements of the CO_2 plume. For a given CCS project, it is understood that there will likely be some period over which the operator has some residual responsibility to confirm stability of the CO_2 plume. 4D data is potentially a key technology in this phase of project life. It is likely that given sufficient time the CO_2 plume will become relatively inactive and it is unlikely that additional seismic surveys will be of significant value once stability has been confirmed.

In addition to seismic monitoring methods, any downhole pressure gauges in wells could be used to support the subsurface monitoring on an ongoing basis. Potential CO_2 movements or leaks would be indicated by pressure reductions, which could be measured by the project operator. In addition to pressure gauges, geochemical monitoring could occur over a relatively wide area at the surface location of a storage project, through airborne or ground coupled recording devices. Any elevated CO_2 levels would be recorded and reported to the operator. However, the more desirable outcome would be to identify any potential leak points before they occur so that mitigation actions can be implemented. 4D seismic data is very useful in that it allows the entire subsurface above the reservoir to be monitored and so leaks within the subsurface can be detected, before they ever reach the surface. The ongoing 4D seismic monitoring of a CO_2 storage is likely to be associated with relatively high costs compared to downhole pressure gauges or geochemical surveys and so there will need to be a balance between costs and ongoing monitoring. The satellite, tiltmeter and gravity methods could also be used during the post-injection monitoring phase and would also be associated with a lower cost, compared to 4D seismic.

Limitations of Seismic Data in Imaging CO_2 in the Subsurface

Where seismic data are used in traditional exploration and development of hydrocarbons, there are clear data limitations, which are similar in the application to monitoring CO_2 in the subsurface. The extent of the limitations are due to numerous factors and some have been mentioned already.

The surface conditions in the area where the seismic data (2D, 3D and 4D) is to be acquired is one of the first considerations. It is typically the case that data acquired offshore tends to provide a better image than data acquired onshore. In offshore areas there aren't typically any obstacles to acquisition apart from existing installations (production platforms etc.) or adverse weather. However, onshore there are numerous considerations. For example, areas of forest may have to be cleared before data can be acquired and desert areas, swamps or tundra can cause issues with the image due to variable velocities in the shallow subsurface. The acquisition of onshore data can also be adversely affected by the presence of rivers, towns and cities.

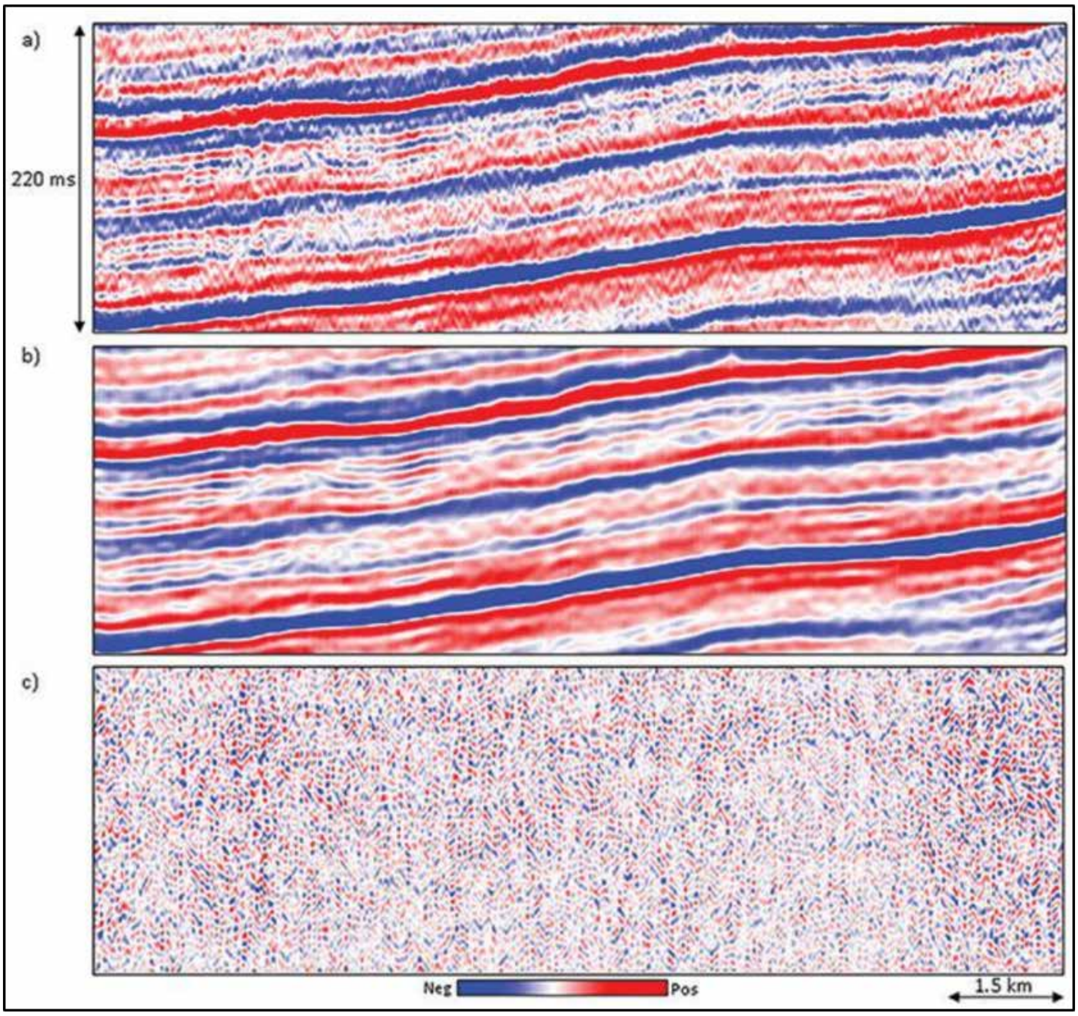
In the subsurface, the type of geology in the overburden, above the target reservoir has a large impact on the quality of the seismic data at the target interval. Very complex structures tend to result in poorer quality data compared to simple layer cake geology. The lithology also has a large impact, highly variable lithologies or certain rocks types such as salt, tend to reduce image quality compared to more homogeneous rock types. Typically, geological formations with low porosity and or permeability tend not to show a strong 4D response. It is unlikely that formations with very low porosity and permeability will be selected as optimal storage locations for CO_2, at least in the early stages of implementation. It is notoriously challenging to get a good image below salt, but data acquisition and processing methods continue to improve and are resulting in better imaging below salt and in areas of highly complex geology. Salt intervals do however tend to provide very good seal properties to any underlying formations and so would be ideal in the respect of also providing a good seal for a CO_2 storage project.

The nature of the target layer itself will also affect the image. Due to the vertical resolution of seismic data, If the interval is very thin i.e. less than 15 to 20 m or has a low density contrast compared to the overlying units it may be challenging to image the interval in detail, but it may still show some 4D response.

In the application of 4D seismic data as an observation or monitoring tool, it is important to consider the repeatability of seismic acquisition. In order to be most useful, 4D monitor surveys should be acquired and processed in exactly same way as the initial baseline survey. This might be challenging in environments, such as desert areas with shifting sands for example. In offshore locations, it may be possible to install a seismic array on the seafloor, which can be left in place and utilised for the acquisition of the baseline and each subsequent monitor survey, resulting in extremely high repeatability and potential cost savings. Four component (4C) seismic surveys (which measure P- and S-Wave motion) may offer additional benefits where there is potentially a limited seismic response to the injection of CO_2.

Permanent arrays can be used onshore as was achieved in the pilot Aquistore project [7], but is typically associated with more issues associated with movement or loss of array components. Noise variation between baseline and subsequent monitor surveys can be a particular problem if steps are not taken to mitigate noise at the acquisition stage. Unexpected noise can lead to additional steps having to be taken at the processing stage which may reduce the ability of the data to show effects of the CO_2 injection, which can be very subtle in certain circumstances (or even undetectable). Noise does however tend to be more of an issue onshore. If care is not taken to remove as much noise possible during acquisition and processing then any subtle effects of injected CO_2 and plume migration may be obscured or masked altogether. Figure 5 is an example of the detrimental effect that noise can have on a subsurface seismic image.

Figure 5: Example of Effect of Noise on Seismic Sections



Source [8]. a) Presents the original 'noisy' data. b) Shows the effect of filtering, which acts to remove the noise. c) Shows the difference between the upper and middle images.

The 4D response (changes over time) are dependent upon the replacement of brine with CO_2 having a density contrast sufficient to be recorded within the monitor survey. In CCS projects, CO_2 is injected at a 'super-critical' liquid phase. Analysis shows that this density contrast is observable under the right conditions (such as the Sleipner example above), but does not offer the same density contrast as is commonly observed between gas and brine. The density of brine is also variable from one location to another as a function of salinity and temperature/pressure, which will be made more complicated with mixing of CO_2 and brine. It might well be prudent to measure the density of the brine in potential storage locations and model the potential 4D response by honouring the particular geological parameters. Through this approach it will be possible to predict the quality of the 4D response to see if a response is likely or not.

The ability to confidently monitor the injected CO_2 plume in the subsurface is likely to be a pre requisite in future, large-scale CCS projects. 4D seismic data is certainly one of the key tools, but will likely require support from other geophysical and non-geophysical methods, such as observation wells in order to achieve high confidence.

Conclusions

The capture and injection of CO_2 into subsurface geological formations has been proposed as a fundamental part of the pathway to reducing CO_2 emissions during the energy transition. Outside of the oil and gas industry, there is limited understanding that CO_2 injection into hydrocarbon bearing reservoirs has been occurring for several decades, albeit in a relatively small scale and commonly associated with enhanced oil recovery.

Over the last decades the number of CCUS projects in development has significantly increased, and many more are planned, particularly in North America, Europe and Asia Pacific [10]. Along with this increase, the tool kit for monitoring CO_2 in the subsurface has kept pace to the extent that it has been demonstrated that a variety of methods (both geophysical and non-geophysical) that can accurately monitor injected CO_2 in the subsurface (Table 1). Technology and understanding continue to evolve, but are generally considered sufficient at present for the safe and long-term sequestration of CO_2 in the subsurface [1]. It falls to experienced technical staff to select and apply the appropriate range of technologies to the particular scenario.

Table 1: Selected CO_2 Monitoring Techniques

Method	Type	Application Phase(s)	Location of Measurement Tool
4D seismic imaging (timelapse 3D)	Seismic (spatially continuous)	Injection, post-injection	Surface
Sparse, semi-permanent seismic array (timelapse)	Seismic (sparse/point)	Injection, post-injection	Surface
Downhole geophone arrays (timelapse)	Seismic (VSP)	Injection	Downhole
Passive / microseismic monitoring	Seismic (Passive)	Injection	Downhole
Downhole pressure measurements	Direct measurement	Injection, post-injection	Downhole
Well log measurements of brine salinity or CO_2 saturation	Direct measurement	Injection	Downhole
Tiltmeter - ground elevation measurements	Geo-spatial	Injection, post-injection	Surface
Timelapse gravity measurements	Gravity	Injection	Surface / Air
Near surface air measurements of CO_2 concentration	Geochemistry	Injection, post-injection	Air
Measurements of CO_2 levels in surface soils	Geochemistry	Injection, post-injection	Surface
Measurements of CO_2 levels in porewater	Geochemistry	Injection, post-injection	Downhole / Near Surface
Electromagnetic measurements of conductivity variations	Direct measurement	Injection	Downhole
Measurement of temperature variations caused by CO_2	Direct measurement	Injection	Downhole
Infrared monitoring for characteristic CO_2 signal	Direct measurement / observation	Injection, post-injection	Surface

Source: Edited after [9 & 2]. Selected CO_2 monitoring techniques and the phases at which they can be applied in a CCUS project lifecycle.

The current limiting factor to the widespread proliferation of CCUS projects is more associated with economic factors than technological factors and it may be that adjustments to government policies are required before this approach to limiting CO_2 emissions can scale-up sufficiently to meet the targets set out during the COP21 meeting. The ability to confidently monitor the injected CO_2 in the subsurface is critical for both project integrity and the acceptance of the process in the general public.

References

[1] Safe Geologic Storage of Captured Carbon Dioxide – DOE's Carbon Storage R&D Program: Two Decades in Review," National Energy Technology Laboratory, Pittsburgh, April 13, 2020.

[2] B. Metz, O. Davidson, H. de Coninck, M. Loos and L Meyer (Eds.) Carbon Capture and Storage, IPCC, 2005. Cambridge University Press, UK. pp 431.

[3] J-S. Fritz (Eds), ECO2 Briefing paper No. 1. The Scientific Basis for Offshore CCS. April 2012. Accessed at: http://www.eco2-project.eu/ECO2%20BriefingPaper1%2004.2012.pdf, in July 2022.

[4] S. Burnison, A. Livers-Douglas, C. Barajas-Olalde, L. Jin, H. Vettleson, J. Hamilton and C. Gorecki, Final report of a scalable, automated, semipermanent seismic array (SASSA) method for detecting CO_2 extent during geologic CO_2 injection, U.S. DOE, Grand Forks, ND, 2017.

[5] R. Trautz, T. Daley, B. Freifeld, P. Cook, M. Robertson, T. Coleman, J. Greer and D. Miller, Distributed Fiber Optic Arrays— Integrated Temperature and Seismic Sensing for Detection of CO_2 Flow, Leakage and Subsurface Distribution: Final Report, U.S. DOE, 2018.

[6] D. E. Miller, T. M. Daley, D. White, B. M. Freifeld, M. Robertson, J. Cocker and M. Craven, Simultaneous Acquisition of Distributed Acoustic Sensing VSP with Multimode and Single-mode Fiber-optic Cables and 3C, CSEG RECORDER, vol. 41, no. 6, pp. 28-33, June 2016.

[7] L. A. N. Roach, D. J. White, B. Roberts and D. Angus, Initial 4D seismic results after CO_2 injection start-up at the Aquistore storage site, GEOPHYSICS, vol. 82, no. 3, p. B95–B107, May-June 2017.

[8] S. Chopra and K. J. Marfurt, Causes and Appearance of Noise in Seismic Data Volumes. AAPG Explorer, Geophysical Corner Article, vol. 35, No. 10, October 2014.

[9] D.N. Espinoza, S. H. Kim and J. C. Santamarina, CO_2 Geological Storage – Geotechnical Implications, KSCE Journal of Civil Engineering (2011) 15 (4): 707-719.

[10] The International Association of Oil & Gas Producers (IOGP), Map of Global CCUS Projects, Overview of Existing and Planned CCUS Facilities. SKU: GRA002_220131. January 2022.