Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

CHARACTERIZATION AND MONITORING TECHNOLOGIES FOR GEOLOGIC CARBON STORAGE

Plains CO_2 Reduction (PCOR) Partnership
White Paper

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Cooperative Agreement No. DE-FE0031838

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May 2022

PCO2R Partnership

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Characterization and Monitoring Technologies for Geologic Carbon Storage

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ACKNOWLEDGMENTS

The authors would like to acknowledge the hard work and dedication of several individuals and organizations, without whose help and support the research described in this report would not have been possible. We want to extend a special thanks to the following individuals:

- Colin McNabb-Seidl, Carrie C. Christianson, Matthew D. Harris, Jeffrey A. Noll, Timothy A. McRae, Lonny L. Jacobson, and Kevin Connors at the EERC for their participation in reviewing the final report and 23 fact sheets. Their contributions enhanced the utility and accuracy of the content of the fact sheets.

- Erik Borchardt (Business Development Manager) and Robert J. Laronga (Unconventional Domain Team Lead) at Schlumberger for their participation in a peer review of the final report and 23 fact sheets. Their comments greatly enhanced the utility and accuracy of many of the fact sheets, as well as provided additional technical information that would not otherwise have been possible to include.

- John Pinkett (Technical Sales Advisor – Wireline and Perforating) at Halliburton for his participation in a peer review of the final report and 23 fact sheets. His comments greatly enhanced the utility and accuracy of many of the fact sheets, as well as provided additional technical information that would not otherwise have been possible to include.

Finally, the authors recognize the tremendous efforts of Loreal Heebink, Erin Hoffert, Dr. Sherry Bollero, Bobbie Rakoczy, Macy Mack, and Kari Suedel at the EERC for their invaluable contributions in the preparation and finalization of this report.

This material is based upon work supported by DOE's National Energy Technology Laboratory under Award No. DE-FE0031838 and the North Dakota Industrial Commission (NDIC) under Contract Nos. FY20-XCI-226 and G-050-96.

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Plains CO_2 Reduction (PCOR) Partnership
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CHARACTERIZATION AND MONITORING TECHNOLOGIES FOR GEOLOGIC CARBON STORAGE

ABSTRACT

A broad variety of commercial geophysical technologies currently exist and are commonly employed in the oil and gas industry that can, and are, being adapted for application in the emerging field of geologic storage of anthropogenic carbon dioxide (CO_2). These technologies are useful for developing data that are critical for site characterization activities and for monitoring, verification, and accounting (MVA) of injected CO_2.

The goal of this work was to provide those involved in the planning and implementation of large-scale CO_2 storage projects with an objective, comprehensive, and updated database of critical information regarding the applicability of a variety of geophysical technologies to site characterization and MVA of injected CO_2. This document provides the information necessary to support decisions and facilitate communications between CO_2 storage operators and geophysical service providers. A review of 23 commercially available geophysical technologies was completed, and 23 fact sheets were compiled in order to provide a comprehensive, objective source that considers the specific applicability of each technology with respect to CO_2 storage. The fact sheets were designed to provide current geophysical technologies and are categorized into a working document that can be quickly referenced for high-level assessments of individual technologies for a given CO_2 capture and sequestration application. This task was funded through the Energy & Environmental Research Center Plains CO_2 Reduction Partnership.

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EXECUTIVE SUMMARY

In 2010, the Energy & Environmental Research Center (EERC) conducted activities to provide those involved in the planning and implementation of large-scale carbon dioxide (CO_2) storage projects with an objective and comprehensive database of critical information regarding the applicability of a variety of geophysical technologies to site characterization and monitoring, verification, and accounting of injected CO_2. In 2021–2022, the EERC conducted activities to provide an update for the previously reported information, necessary to support decisions and facilitate communications between CO_2 storage operators and geophysical service providers.

The project was completed through reviewing and updating four categories: 1) technology descriptions of downhole wellbore geophysical technologies, 2) evaluation of surface and combined surface and downhole geophysical technologies, 3) geophysical database, and 4) technology transfer. In total, 23 commercially available geophysical technologies were reviewed, updated, evaluated, and had fact sheets compiled. The fact sheets were created to provide a comprehensive, objective source that considers the specific applicability of each technology with respect to CO_2 storage. The fact sheets were designed to provide current geophysical technologies and to categorize them into a working document that can be quickly referenced for high-level assessments.

Key Points

- Individual fact sheets were created and/or updated for 23 commercially available geophysical technologies:
  - Information was obtained through publicly available literature, sales literature, interviews with service providers, technical papers, and journal articles.
  - Every attempt was made to minimize service company bias through the use of generic terminology and cross-referencing where applicable.

- Each fact sheet consists of the following sections:
  - General operational overview
  - Applications
  - Deployment logistics:
    - Tool limitations
    - Sources of measurement error
  - Lead time required to deploy technology

- Brief overview of selected case studies
- Price estimates
- References

- In order to facilitate fact sheet development, if a common or novel application, tool limitation, or source of error was listed for a given technology, it was included in that technology's fact sheet. A variety of similar geophysical technologies and tools are available from most service providers and between various service providers. This work does not compare and contrast measurements between various tools or service companies; rather, it is designed to give an overview of available technologies. Therefore, all applications and concerns must be discussed with a selected geophysical service provider on a case-by-case basis to ensure that the correct technology is deployed and valid data are acquired.

- Certain geophysical technologies require data processing or interpretation, which may require supplementary data. Although applications for each measurement category are presented, specifics on the interpretation methodologies from the tool output are not detailed nor are supplementary data requirements, as they can be highly site- or processing-specific, which is beyond the scope of this work.

- Many tool limitations and sources of error are listed as a method of quality control so that they may be addressed prior to technology deployment; however, they may not be applicable in many circumstances. Many service companies will address and correct these issues during data acquisition or processing; therefore, this may be of no concern.

- Pricing estimates are shown as low (<\$25,000), medium (\$25,000–\$100,000), and high (>\$100,000). Pricing can fluctuate drastically and can be affected by many variables, both technical (such as depth, reservoir pressure, measurement resolution) and nontechnical (such as geographic location, the oil and gas market within a given region, etc.). Price estimates were compiled from a variety of service providers, both through the course of this project and previous EERC experience, and are based on a generic North Dakota deployment in 2021.

- Fact sheets were peer-reviewed by two major oil and gas industry geophysical service providers (Schlumberger and Halliburton).

Technology, interpretation techniques, and best practices are constantly evolving within both the oil and gas and the emerging CO_2 capture and sequestration industries. While this work provides assessments of individual technologies, it was primarily designed as a means to facilitate informed discussions between geophysical service providers and CO_2 storage stakeholders. It is highly recommended that decisions regarding geophysical technologies not be based solely or partially upon the information presented in this work but be evaluated based on each unique project by both the CO_2 storage stakeholders and geophysical service providers. This task was funded through the EERC Plains CO_2 Reduction Partnership.

CHARACTERIZATION AND MONITORING TECHNOLOGIES FOR GEOLOGIC CARBON STORAGE

INTRODUCTION

A broad variety of geophysical technologies currently exists that may be useful for application to the emerging field of geologic storage of anthropogenic carbon dioxide (CO_2). Geophysical technologies may include downhole wellbore devices, surface-deployed devices, and/or combinations of the two. These technologies can be used to develop data that are critical for site characterization activities related to monitoring, verification, and accounting (MVA) of CO_2 in the subsurface once an injection project is operational. Geophysical technologies are typically developed and offered by oilfield service companies such as Baker Hughes, Halliburton, Schlumberger, Weatherford, and others. While these companies publish basic information on the general capabilities of their respective technologies, detailed evaluations require discussion and site-specific assessments to determine applicability to a site-specific project. Furthermore, no comprehensive, objective source in the literature currently considers the specific applicability of each technology with respect to CO_2 storage. An objective evaluation of the most commonly used and emerging commercial geophysical technologies in the oil and gas industry will provide CO_2 storage researchers, project managers, and other stakeholders with a previously unavailable tool to support decisions regarding the implementation of cost-effective site characterization and MVA.

METHODOLOGY

Technology Review

In total, 23 commercially available geophysical technologies were reviewed, evaluated, and documented in individual fact sheets. The fact sheet approach for each technology was chosen to facilitate database development and technology transfer and to increase the versatility of the information by allowing a concise standardized presentation of each technology. Table 1 presents the technologies reviewed by the Energy & Environmental Research Center (EERC) and their application to CO_2 capture and storage (CCS) in terms of characterization or MVA.

Table 1. Technologies Reviewed and Their Application to CCS

Fact Sheet Master List	Abbreviation	Application	
		Characterization	MVA
Capture Spectroscopy	CS	•	
Cement Bond Logs	CBL		•
Dielectric Dispersion	DD	•	•
Distributed Fiber Optics	DFO		•
Downhole Seismic (VSP, crosswell)	DS	•	•
Downhole Fluid Sampling, Temperature, and Pressure Testing	DSTP	•	•
Electrical Borehole Imaging	EBI	•	
Electromagnetic	EM		•
Gamma Ray	GR	•	
In Situ Testing and Sampling	ITS	•	•
Multifinger Caliper	MC		•
Microdeformation Monitoring	MDM		•
Microseismic	MS		•
Nuclear Magnetic Resonance	NMR	•	
Nuclear Porosity (neutron and density)	NP	•	
Pulsed Neutron	PN		•
Resistivity and Microresistivity	RES and MRES	•	•
Sidewall Coring Tools	SCT	•	
Sonic	SON	•	•
Spectral Gamma Ray	SGR	•	
Spontaneous Potential	SP	•	
Surface Seismic (2D, 3D, 4D)	SS	•	•
Ultrasonic Imaging	UI	•	•

Much of the information presented in the fact sheets, including pricing, was collected through literature review, discussions with geophysical service providers, and previous EERC experience, including Plains CO_2 Reduction (PCOR) Partnership experience gained during field validation and demonstration studies.

The major categories represented on each fact sheet are listed as follows:

- Overview
- Applications
- Deployment logistics:
  - Tool limitations
  - Sources of measurement error
- Lead time required to deploy technology
- Identification and brief review of selected CCS case studies and key findings (if applicable) with references

- Price estimate (representing a generic deployment in the North Dakota portion of the Williston Basin based on 2021 pricing)

- References

- Visual aids

Only commercially available technologies were reviewed. While multiple U.S. Department of Energy (DOE) CCS regional partnerships have investigated and deployed, or are developing, technologies for the purposes of monitoring injected CO_2, it was felt that large-scale commercial CCS operations would most likely focus on commercially available technologies contracted through geophysical service providers rather than developing and field-testing novel technologies (which have increased inherent risk and higher deployment costs and are considered unproven in many cases). It is also expected that regulatory agencies will not mandate the use of novel technologies during permitting of CCS sites. While novel technologies may, and likely will, prove beneficial for CCS MVA activities, they are not yet mature and lack the widely understood interpretation techniques that have been developed for commercial applications.

Commercially available geophysical technologies are especially important as they are one of the few technologies for which a vast knowledge base exists and are readily accessible through oil and gas industry service providers. Each individual fact sheet was compiled in such a manner as to supplement the two aforementioned works by expanding "geophysical technologies" into individual measurement categories, including applications, limitations, pricing, and lead time. It is anticipated that these fact sheets will provide CO_2 storage researchers, project managers, and other stakeholders a tool to quickly evaluate a technology's applicability to an individual project and facilitate informed discussions with service providers to ensure satisfactory results for characterization and MVA programs.

Fact Sheet Development

The fact sheets were constructed through a literature review, examination of multiple service providers' published sales materials and case studies, discussions with service providers, and the PCOR Partnership Phase II field validation experience.

A number of service providers are available for geophysical technologies, each with a host of technologies designed for specific applications, many of which develop and manufacture proprietary tools. Additionally, various forms of advanced and vintage tools exist and are in use within the oil and gas industry; therefore, not all applications are available for all tools of a given type. While many services are comparable among service providers, certain specific applications or measurements may be unique. Specific applications and requirements should be thoroughly discussed with the service company provider to ensure successful data acquisition and processing for a given application.

To facilitate fact sheet development, if a common, novel, or potential application or tool limitation was listed for a given technology, it was included in the fact sheet; however, this by no means implies that the service is available through all service providers and, if available, may require additional information or calibration to other data.

Tool limitations and sources of error are listed as a method of quality control and may not be applicable in many circumstances. Many service companies will address or correct these issues during data acquisition or processing; therefore, they may be of no concern to the end user. These issues are presented in the fact sheets so that they can be discussed prior to data acquisition.

Some technologies may be limited to certain operating environments. For example, oil-based drilling fluid, saltwater-based drilling fluid, or multiple technologies may be available that are each uniquely suited for a different operational environment. For the purpose of fact sheet development, if an application or limitation was listed or known to exist, it was included even though it may not be applicable for all available tools for a given technology.

Tool diameters; lengths; weights; and operational limitations, such as pressure and temperature ratings, exist and vary between each individual tool and service provider. Because of the sheer quantity of tools available, each with different operational ratings, operational ratings were not included in the fact sheets. While every tool is designed for operation in the oil and gas industry, which should be sufficient for most CCS applications, specific operational conditions at a given CCS site should be discussed with the service company provider.

A brief description of assorted case studies and associated citations obtained from a limited literature review pertaining to each geophysical category's application to CCS projects is presented where applicable. The case studies section is not all-inclusive, as much of the work has been previously published and summarized and is available through a variety of sources (DOE best practices manual, regional partnership web sites, Society of Petroleum Engineers papers, etc.); however, the section was included for increased fact sheet utility.

Pricing was based on 2021 pricing estimates reviewed through a variety of service providers and previous PCOR Partnership experience. A generic North Dakota well between 5000 and 10,000 feet in depth was used to estimate pricing for downhole geophysical technologies. Surface-deployed geophysical technologies were estimated on 2021 pricing for a North Dakota deployment. Pricing can fluctuate drastically depending on the oil and gas market and geographical location. 2021 North Dakota pricing was given for comparative purposes only, does not include rig operational time or associated costs (services provider costs only), and may not be representative of pricing in all areas. Typically, work is, and should, be bid out to a single company or multiple service companies during project planning, a process which will provide realistic pricing for a given application.

Technology, interpretation techniques, and best practices are constantly evolving within the oil and gas and CCS industries. Each individual fact sheet provides information to quickly evaluate a commercially available technology in terms of applicability for either site characterization or MVA. However, it is important to consider that each fact sheet should only be used as a guide to facilitate informed discussions with service providers so that CCS decision-makers can be informed consumers. It is designed to aid the stakeholders in ensuring the correct questions are asked, services selected, and risks discussed so that satisfactory results and project goals are achieved.

Summary

This work outlines commercially available geophysical technologies that have applications to CCS projects in terms of both characterization and MVA. While many service providers offer comparable technologies, specific measurement applications can vary between individual geophysical tools (within an individual service provider and among service providers). This work does not compare and contrast measurements between various tools or service companies. Rather, it is designed to give an overview of available technologies and their corresponding applications, limitations, pricing, and other applicable information. This will allow a CCS stakeholder to quickly evaluate whether a specific technology is suitable for a particular CCS project. It will also facilitate informed discussions among CCS stakeholders and service providers in order to ensure satisfactory results for characterization and MVA programs.

Geophysical technologies, interpretation procedures, and best practices can evolve rapidly in both the oil and gas and CCS industries. Furthermore, certain applications include an interpretation component that may require additional supplementary data. Therefore, it is often better to discuss specific project requirements and goals with service providers rather than specifying technologies to be utilized. This will ensure that expectations are met and that a more applicable or cost-effective solution is not available for a specific deployment. It is highly recommended that decisions regarding geophysical technologies are not based solely or partially on the information presented in this work but rather on each unique project.

Although applications for each measurement category are presented, specifics on the interpretation methodologies from the tool output are not detailed in this report as they can be highly site-specific and require a thorough understanding of geology, geophysics, petrophysics, and other scientific fields, which is beyond the scope of this work. Pricing can vary widely among logging programs, service companies, and geographic locations and over time; therefore, a competitive bidding system is typically used by operating and service companies to obtain geophysical work.

Each fact sheet represents a tool to provide those involved in the planning and implementation of large-scale CO_2 storage projects with an objective database of critical information regarding the applicability of a variety of commercially available geophysical technologies to site characterization and MVA (Table 2).

Table 2. Abridged Summary of Potential Applications for Commercially Available Geophysical Technologies*

Summary of Common Usages for Geophysical Technologies	CBL	CS	DD	DFO	DS	DSTP	EBI	EM	GR	ITS	MC	MDM	MS	NMR	NP	PN	RES and MRES	SCT	SGR	SON	SP	SS	UI
Assess Cement and/or Cement Bond Quality	•			•																			•
Assess Zonal Isolation Between Formations	•																						•
Identify Channeling and/or Microannuli	•			•																			•
Detect and Monitor Casing Corrosion, Damage, and Wear				•				•			•												•
Detect and Monitor Scale and/or Wax Buildup								•			•												•
Locate Perforations				•				•			•												•
Indicator for Wellbore Remediation Activities	•			•				•			•												•
Clay Analysis		•							•					•	•		•	•	•		•		
Lithological or Mineralogical Fractions and/or Weight Percent		•														•		•					
Lithology or Mineralogy		•							•						•	•	•	•	•	•	•		
Porosity Assessments or Analysis		•			•		•							•	•		•	•		•	•	•	
Geomechanical, Mechanical Rock Properties, and Stress Analysis					•		•			•	•	•	•		•			•		•		•	•
Seal Integrity Assessment				•	•	•				•		•	•					•				•	
Detection and Analysis of Faults or Fractures				•	•		•			•		•	•				•	•	•			•	•
Formation Dip and/or Strike					•		•										•	•				•	•
Sedimentary Structure/Rock Texture/Facies Analysis			•				•											•	•				•
Identify Anisotropy				•	•		•			•	•						•	•		•		•	•
Structural Imaging					•																	•	•
Analysis of Fracture Initiation, Propagation, or Closure Pressures										•		•						•					
Identification of Pore Size Distribution							•							•				•					•
Bulk Density															•			•					
History Matching				•	•	•				•		•				•						•	
Correlation Between Well and/or Multiple Runs with a Well				•					•								•	•	•		•		
Temperature and/or Temperature Profiles				•		•				•													
Synthetic Seismograms															•					•			
Permeability Assessment or Analysis		•			•		•			•				•	•	•	•	•	•	•	•	•	
Bound Versus Free Fluid Analysis														•				•					
Capillary/Pore Pressure Predictions		•			•	•				•				•				•		•		•	
Pressure Analysis or Pressure Gradient				•		•				•		•			•								
Formation Resistivity and/or Formation Fluid Resistivity							•										•	•			•		
Geochemical Analysis of Formation and/or Formation Fluids		•		•		•				•								•					
Fluid Saturation Assessment or Analysis		•	•		•	•				•					•	•	•	•		•	•	•	
Fluid Typing						•				•				•	•	•	•	•		•			
Fluid Density/Viscosity/pH Determination				•		•				•				•									
Pressure or Pressure Front Monitoring				•	•	•				•		•	•									•	
Plume, Plume Front, or Breakthrough Monitoring				•	•	•				•		•				•	•			•		•	
Monitor Fluid Saturation Changes			•		•	•				•				•	•	•	•			•		•	
Monitoring for Leakage				•	•	•				•		•	•			•	•			•		•	•
Injectivity Monitoring				•		•																	
Formation Fluid Salinity			•																				
Locate Well Completion Components				•				•			•												•
Logging while Drilling (LWD)		•			•				•	•				•	•		•		•	•			•
Monitor and/or Map Hydraulic Fractures or Induced Seismicity				•								•	•										

* Table 2 is presented as a quick reference guide relating to the corresponding geophysical technologies fact sheets. If a common, novel, or potential application was listed for a given technology, it was included on the fact sheet; however, this by no means implies that the service is available through all service providers. Listed applications may require additional information or calibration data. Only summarized applications are presented in Table 2; individual fact sheets provide expanded detail and applications. Fact sheets and Table 2 were constructed as a guide to facilitate informed discussions with service providers and should only be used as such.

CONVEYANCE SYSTEMS

Downhole Conveyance Systems

Cable/Wireline

Cable or wireline conveyance is the most common and, typically, the lowest-cost method of conveyance for downhole geophysical tools. Wireline conveyance requires either a rig or a crane on-site and utilizes a service company-provided wireline cable, winch, and acquisition system to provide both a mechanical and electrical connection to the downhole tools, thereby allowing real-time data evaluation. Two basic types of cables can transmit an electrical signal to the tools downhole: multiconductor and single conductor.

Multiconductor lines are constructed to withstand working loads of up to 20 klbf and transmit an electrical signal through four to seven conductors. The conductor lines are protected by armored wires that are wound around the core. Common sizes range from 0.377" to 0.548" in diameter and can increase slightly if the outer wires are protected by a polymer sheath.

Single conductor cables are similar in design to multiconductor cables but only have one conductor. The size of the single conductor lines ranges from 0.1" to 0.313" in diameter and can support working loads of up to 7735 lbf. Because of their size, single conductor cables can be used in pressurized wells, making them ideal for pressure testing, noise and pulsed neutron logging, fluid sampling, and flow monitoring.

Operationally, geophysical logging tools are lowered to a measurement depth utilizing their own weight and then retrieved using the winch system while measurements are taken. Wireline is typically suited for boreholes with deviations less than approximately 60° but has been successfully deployed in wellbores with deviations in excess of 70°. If present, deviation should be discussed with the service provider prior to any deployment, as some tortuous wellbore trajectories can cause concern.

Digital Slickline (DSL)

Similar to cable/wireline conveyance, DSL conveyance requires either a rig or a crane on-site and utilizes a service company-provided winch, DSL cable, and radio frequency (RF) transceivers (for surface and downhole data acquisition). DSL using RF communications have been used in oil and gas operations since 2016. DSL conveyance can be used as a replacement service for perforating runs, production logging, plug setting (explosive and nonexplosive), etc. Common material selections include a polymer-coated high-breaking strength alloy slickline, a coupled RF antenna and transceiver for surface data acquisition, and a downhole transceiver for tool sensor communication.

One of the features that separates DSL is maintaining the connection in a coated pipe or scale that hinders the tool from contacting the inner wall. Deepwater applications normally require a cable to be run from the surface to the wellhead on the sea floor. DSL logging operations can acquire all the data required without the need for communication to be “hardwired.” Another opportunity leveraged against traditional conveyance systems is the ability to have real-time depth control and confirmation that downhole equipment has been pulled or set with in situ pressure, temperature, vibration, and downhole stress.

Since the introduction of DSL, the distribution has been 60% slickline with heavy jarring and 40% replacement of e-line services performing diagnostic logging or plug setting and perforating. As the technology progresses, more applications will be realized and applications to CCS will most likely include well completion and plug setting operations.

Coiled Tubing (CT)

CT is a wireline alternative that can be deployed with or without a rig or crane on-site. CT is used primarily in the cased-hole environment to convey logging tools through doglegs and bends and into the horizontal section of a well. While this conveyance method is more costly, the coiled tubing provides higher compressional strength and rigidity, allowing for operation in deviated, horizontal, or tortuous boreholes. CT may offer an operational benefit as some service providers offer optical electrical systems that allow for simultaneous electrical and distributed-temperature system measurements. CT can provide either a mechanical-only connection, for memory tools that record and store data downhole within the tool, or a mechanical and electrical connection for nonmemory geophysical tools that record and transmit data to a surface acquisition unit when real-time data evaluation is necessary.

Logging While Drilling (LWD)

Advancements in geophysical evaluation technology and drilling bottomhole assembly (BHA) components have allowed for LWD tools to communicate real-time borehole data to the surface without involving wireline or cable conveyance. LWD can be risky and expensive but has the advantage of measuring properties of a formation before drilling fluids deeply invade the zone. In difficult or highly deviated wellbores, LWD measurements ensure the subsurface data is captured if wireline operations are not possible. Timely LWD data can also be used to guide well placement so the wellbore remains within the zone of interest.

Drill Pipe

Drill pipe conveyance, also commonly referred to as pipe-conveyed logging, utilizes drill pipe to which the geophysical tools are mechanically attached using specialized adapters to lower the tools to the desired measurement location. After the tools are positioned, a specialized connector, known as a “wet connect,” is attached to a wireline cable (used to provide the electrical connection to the logging tools) and is pumped down the inside of the drill pipe from the surface until it engages a latching mechanism on the tools. The cable and the drill pipe are then simultaneously pulled out of the hole while data are acquired. Drill pipe conveyance is generally more costly and time-consuming than traditional wireline conveyance methods and is, therefore, typically only used in openhole logging operations with deviated or horizontal wellbores.

SUPPLEMENTAL CONVEYANCE METHODS

Tractor (wireline conveyance)

Tractor conveyance uses an additional mechanical propulsion tool, known as a "tractor," which is mechanically and electrically connected to the wireline-conveyed geophysical tool string. Tractor designs are available that allow logging while the tractor mechanically pushes or pulls the tool string; however, some systems require the tractor to be "shut down" before data acquisition can begin. Tractor technology is often a low-cost alternative for highly deviated or horizontal wells where keyseating and hole rugosity are not a concern, such as in a cased-hole environment. Tractor conveyance is commonly used for production logging, analysis behind casing logging, and perforation services in cased-hole environments in deviated wells.

Openhole tractor conveyance operations have been successfully completed in deviated and horizontal wellbores. Specifically, high success rates in some operational environments have been achieved to "log the curve," where the geophysical tools are not conveyed more than a few hundred feet into the horizontal section in openhole portions of horizontal wells within highly consolidated formations. While utilizing tractor conveyance can produce significant cost and time savings over drill pipe or coiled-tubing conveyance methods, the service provider should be consulted to determine applicability and fully evaluate and discuss the risk potential prior to any operations.

As mentioned, keyseating can be an issue when utilizing tractor conveyance in an openhole environment. Keyseating occurs when the cable wears into the borehole wall over a deviated section of borehole, creating a slot that is too small for the tool to pass. Once a slot has been cut, there are generally four possible mechanisms that cause the cable to be trapped: 1) differential sticking, 2) reactive slot swelling, 3) borehole stress, and 4) mechanical binding. Special attention must be paid to formation type, consolidation, and the yield stress in the formations where the tractoring operation will take place.

Pump Down (wireline conveyance)

Pump-down conveyance utilizes hydraulic pressure to push geophysical tools down deviated or horizontal portions of the wellbore while being connected to a wireline. Pump-down conveyance is typically the quickest and most cost-effective method for conveying geophysical tools or perforating guns into deviated or horizontal sections of the borehole in a cased-hole environment.

Memory (drill pipe or coiled-tubing conveyance)

Memory tools are used by many well-logging companies. A lithium battery is used to supply tool power while measurements are acquired and stored in onboard tool memory. A specified operation sequence (power up, open or closed calipers, etc.) is programmed into the tool at the surface, prior to deployment, with the sequence automatically initiating after a specified amount of time has elapsed, with drill pipe or coiled tubing providing the rigid mechanical connection for the tools. Once the logging interval is reached and the operational sequence has initiated, the tool begins recording data to internal memory, and the drill pipe or coiled tubing is pulled out of the hole at a slow rate while the well is being logged. Once the tool is returned to the surface, the data are downloaded, merged with the depth measurements related to the time domain, and processed.

Memory tools are typically used as a contingency service for openhole applications when hole conditions are of concern or to reduce well-logging times. Specialized drill bits and associated adapters utilizing pump-down deployment are available to accommodate memory-logging operations without pulling the drill pipe out of the hole to rig up logging equipment. This method of conveyance is ideal for highly deviated, horizontal, tortuous, or rugose boreholes or when fishing operations seem likely because of borehole conditions.

Summary

It is important to discuss special requirements (such as deviated or horizontal borehole well logging) and any deployment concerns (borehole problems, lost circulation zones, etc.) with the service provider during the planning stages and again prior to deployment of any downhole geophysical logging program. Expected and potential wellhead and downhole pressure is a special concern that should be thoroughly discussed with the service provider prior to deployment. Certain technologies and/or conveyance methods may be better suited to a given application than others. Specialized equipment is required, which is dependent on the expected wellhead pressure process. Typically, conveyance and pressure control is left to the discretion of the service provider; however, concerns and risks associated with conveyance systems and technologies should be fully discussed prior to deployment. Table 3 provides a summary guide for conveyance applications.

Table 3. Downhole Geophysical Well-Logging Conveyance Applications Guide

Technology	Vertical Wells	Deviated Wells <60°–70°	Deviated Wells >60°–70°	Tortuous Wells	Curve	Horizontal Wells	Flowing Wells
Wireline	Both	Both		Both			Both
DSL	Both	Both		Both			Both
CT	Both	Both	Both	Both	Both	Both	Both
LWD	Openhole	Openhole	Openhole	Openhole	Openhole	Openhole	
Drill Pipe		Openhole	Openhole	Openhole	Openhole	Openhole	
Tractor		Both	Both		Both	Cased Hole	Both
Pump Down		Cased Hole	Cased Hole	Cased Hole	Cased Hole	Cased Hole	
Memory	Both	Both	Both	Both	Both	Both	Both

Legend	
Openhole	(red)
Cased Hole	(green)
Both	(blue)

CAPTURE SPECTROSCOPY

Capture spectroscopy (CS) is used to analyze mineralogical and elemental yields of the downhole environment by detecting elemental concentrations achieved by measuring the captured spectrum of a variety of elements (Schlumberger, 2021a,b). Elemental spectroscopy tools apply a radioactive source to excite the formation (Halliburton, 2019) in order to measure elemental concentrations of silicon, iron, calcium, sulfur, titanium, gadolinium, chlorine, barium, and hydrogen.

CS enhances mineralogical and geochemical reservoir analysis, similar to techniques used for special core analysis. Spectroscopy is especially beneficial for analyzing complex reservoirs with laminated beds, correlating between wells, and determining mineralogy.

Applications

- Measure enhanced suite of elements in real-time, including Al; Ba; C; Ca; Cl; Fe; Gd; K; Mg; Mn; Na; S; Si; Ti; and metals, such as Cu and Ni (Schlumberger, 2017; Weatherford, 2020).

- Input accurate bulk mineralogy to software for lithofacies classification to target intervals with superior reservoir and completion quality (Schlumberger, 2017).

- Matrix properties for petrophysical evaluation, accurate density porosity calculation, gas identification through matrix-corrected neutron and density, and accurate formation fluid sigma (Schlumberger, 2017).

- Measure clay fraction independent of gamma ray (GR), spontaneous potential, and density and neutron measurements (Schlumberger, 2006).

- Analyze dry-weight lithology fractions: total clay, total carbonate, gypsum or anhydrite, QFM (quartz, feldspar, mica), pyrite, siderite, coal, and salt fractions for complex reservoir analysis (Schlumberger, 2006; Halliburton, 2019; Weatherford, 2020).

- Matrix properties: matrix grain density and matrix thermal and epithermal neutron values (used for more accurate porosity calculations) (Schlumberger, 2006; Halliburton, 2019; Weatherford, 2020).

- Matrix sigma for saturation analysis (Schlumberger, 2006; Halliburton, 2019).

- Geochemical stratigraphy for well-to-well correlation (Schlumberger, 2006; Halliburton, 2019).

- Recommend enhanced completion and drilling fluid based on clay versus carbonate cementation (Schlumberger, 2006).

- Predict quantitative lithology and pore pressure when used in conjunction with seismic data (Schlumberger, 2006).

- Improve estimates of permeability based on mineralogy (Halliburton, 2019).

- Estimate coalbed methane bed delineation, producibility, and in situ reserve (Schlumberger, 2006).

Deployment Logistics

Operating Environment: Openhole, Cased Hole

Tool Limitations

- Limited ability to detect basalt carbonation in freshwater reservoirs, unless a pronounced preferential release and/or binding of a specific major citation is induced by CO_2 injection (Zakharova and others, 2012).

- Temperature effects can significantly reduce the efficiency of the spectroscopy tool; higher temperatures result in poor signal-to-noise ratio and may cause a decrease in resolution. Maximum expected borehole temperature should be discussed with the service company representative during planning (Integrated Ocean Drilling Program, 2008). Verify the generation of tool being used as this issue has been addressed via better detector technology in new-generation tools (Schlumberger, 2017).

- In holes with severe washouts or in high-porosity sediments, the signal may be dominated by aluminum and hydrogen, which could alter the statistics of the elemental yields (Integrated Ocean Drilling Program, 2008).

- Some older generations of tools require chemical radioactive sources, whereas newer-generation tools have a powered neutron generator.

Sources of Error

- Interference on the measured spectrum from the borehole environment or the tool housing may affect measurements (Egbe and others, 2007).

Lead Time Required to Deploy Technology

Typically, CS logging services are included during the initial planning of the logging program, a few weeks to a few months before the estimated logging date. Because of CS's specialized use, not all companies may have CS tools available on-demand; therefore, sufficient time may be necessary to ensure tool availability.

Case Studies and Key Findings

CS logging has seen abundant use in the field since its inception and is widely used in the oil and gas industry for characterization purposes.

One such example is the evaluation of regional lithology for CO_2 storage in southeastern Ohio conducted to investigate the feasibility of carbon sequestration using information gathered from a single test well at a coal-fired power plant in the Appalachian Basin. A number of wireline tests, including elemental CS, were conducted to further analyze the geologic formations, lithologies, and natural gas shows (Meggyesy and others, 2008). Samples from sidewall coring were also taken and studied to find the best CO_2 storage units with influence from the geophysical testing results (Meggyesy and others, 2008).

Another example of characterization includes the Devonian Ohio Shale of eastern Kentucky, the state's most prolific gas producer. A study was conducted that focused on reservoir modeling and simulation for enhanced gas recovery and CO_2 storage capabilities (Schepers and others, 2009). The study utilized elemental CS and mineralogy x-ray diffraction measurements of samples taken from formations from the middle and upper Huron Member of the Ohio Shale. These analyses identified an eventual potential for enhanced gas recovery using CO_2 injection. The study concluded that continuous CO_2 injection could be viable; however, the huff 'n' puff scenario did not generate enhanced gas recovery (Schepers and others, 2009).

The contrasts in properties and the mixing behavior of CO_2 and brine provide unusual conditions for water–rock interaction during CO_2 injection and storage. The mineral dissolution rate is dependent on the degree of under-saturation of the solution and the kinetics of reaction (DePaolo and others, 2013). Precipitation of secondary minerals also depends on the solution saturation state. One of the difficulties in accurately estimating rock dissolution rates is knowing the actual mineral surface area that is involved in the dissolution reactions at any time. A way to determine the mineral surface area connected to fluids is to couple electromagnetic imaging and spectroscopy (e.g., focused ion beam scanning electron microsope and CS, respectively) with tomographic characterization of pore networks (Landrot and others, 2012).

In a comparison of CS tool measurements with lab-derived core data from the Weatherford Rock Formation Lab (United States) and Callisto Facility (United Kingdom), results were similar for formation sigma and all elemental concentrations (Pemper, 2020).

Price Estimates

- CS (low cost)

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CEMENT BOND LOGS

Cement bond logs (CBLs) are used primarily to assess bond integrity between the cement-to-casing and cement-to-formation interfaces by measuring the loss of acoustic energy as acoustic waves are attenuated through interactions at the cement interfaces and by the cement itself. The amount of attenuation relates to the fraction of the casing perimeter covered by cement (Bybee, 2007; Schlumberger, 2021; Baker Hughes, 2020). Typically, CBLs are performed on wells upon completion when required by state or federal regulations or to avoid potential well problems. Furthermore, CBLs may have applications to CO_2 storage in terms of both risk assessment and monitoring, verification, and accounting of new and existing wells, which may potentially intersect the CO_2 plume.

Cement is critical to mechanical well integrity by providing sufficient casing support within a wellbore, protecting the casing from fluid corrosion, and properly isolating production or injection zones. CBL measurements may provide an indication of poor cement coverage, poor bonding, or weakness in the cement. The detection of poor cement, or the absence of cement, can indicate remedial action is needed, thus avoiding potential well problems and their associated costs (Schlumberger, 2021).

Cement bond measurements are typically also sensitive to the effect of a microannulus (a small annular gap that can form between the casing and cement sheath, approximately 0.01 to 0.1 mm) (Bybee, 2007). This problem usually develops because of variations in temperature and pressure after the cement begins to set. A microannulus can allow drilling, produced, or injected fluids to flow outside of the casing into unwanted subsurface zones during operations (Schlumberger, 2021).

Ultrasonic CBL tools may be more prudent than CBL–variable-density log tools for acquiring logs in wells near CO_2 plumes or in those being utilized as CO_2 injectors. Ultrasonic tools are less sensitive to microannuli (leak paths), distinguishing between liquid- and gas-filled channels, directly measure casing quality (thickness, corrosion, wear), and radially map cement placement, aiding in the determination of proper wellbore isolation of the zone of injection.

Applications

- Determine cement bond quality between the casing, cement, and formation to confirm zonal isolation (PETROLOG, 2006; Bybee, 2007).
- Locate free pipe and identify top of lead and tail cement (Halliburton, 2016; Schlumberger, 2007; Weatherford, 2016, Baker Hughes, 2020).
- Evaluate cement bond quality radially in deviated and horizontal wellbores.
- Detect casing collars.

- Locate areas with direct casing-formation contact (absence of circumferential cement contact with casing).

- Indicate remediation activities (Bybee, 2007).

Deployment Logistics

Operating Environment: Cased Hole, Downhole

Tool Limitations

- Many CBL tools require a fluid-filled wellbore so that acoustic coupling between the tool and the casing, cement, and/or formation can occur. However, advanced CBL tools, which may not be available from all service companies, do exist that utilize pad-mounted sensors, thereby negating the need for a fluid-filled borehole and/or tool centralization (PETROLOG, 2006).

- Data accuracy can be influenced by a nonuniform cement sheath around the casing (Edgson and Mehta, 1983).

- If a microannulus is present, the cement-to-formation interface may be difficult to analyze.

Sources of Error

- Many CBL tools need to be centralized in the borehole for accurate measurements. Steel centralizers, attached to the tool to provide proper centralization within the casing, must have the same diameter as the inside of the casing. Completion information should be discussed with the service provider prior to operations to ensure proper centralization (PETROLOG, 2006; Edgson and Mehta, 1983).

- CBL measurements can be negatively impacted by dense fluids within the wellbore.

- A microannulus can develop if the casing contracts when wellbore pressure is lowered below the pressure present when the cement was initially cured. A microannulus may appear during the bond log but may not be present under normal operating conditions because of increased wellbore pressure during production or injection. Alternatively, a microannulus which is normally present may not be detected during a bond log if the wellbore pressure is increased over normal operating conditions.

Lead Time Required to Deploy Technology

Casing bond evaluations are considered a standard cased-hole evaluation service and are run in most newly completed wells to confirm zonal isolation of production or injection zones from other aquifers or reservoirs. Typically, services are selected during the initial planning stages of the drilling or logging program a few weeks to a few months before the estimated well completion date; however, since cement bond evaluation service is considered a standard logging service for nearly all cased-hole service companies, the service could be requested on-demand with as little as 6 hours of lead time.

Case Studies and Key Findings

A two-phased development plan offshore of Sarawak, Malaysia, involved an extensive well integrity assessment. The potential leakage points were the cement-to-formation interface and the casing-to-cement interface. CBLs, sustained annulus pressure (SAP), and impact of subsidence to the current development wells were analyzed, and the results were incorporated into the well evaluations (Tiwari and others, 2021). The construction material used for casing and cement were non-corrosion-resistant and could create a potential leakage pathway for injected CO_2. It was concluded that none of the existing producers could be converted into CO_2 injectors and all needed to be permanently plugged and abandoned.

A study in Alberta, Canada, utilized CBL tools to evaluate CO_2 and gas leakage potential along wellbores. A suite of casing inspection logs were evaluated against CBLs to detect both internal and external corrosion for 500 wells known to have casing failure (Watson and Bachu, 2007). The CBL evaluation was used to confirm that the majority of wellbores were well cemented and zonally isolated in the deeper sections of the wellbore, thus reducing the probability of leakage through the casing from deep, uncompleted reservoirs (Watson and Bachu, 2007).

Price Estimates

- CBL (low)

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DIELECTRIC DISPERSION

Dielectric dispersion (DD) logging based on single-frequency measurements was introduced in the late 1970s (Calvert and others, 1977), primarily to determine water-filled porosity independent of RES as well as salinity independent of water saturation (i.e., water saturation can be determined in freshwater environments). Many oil and gas operators were pleased with the results because of the ability to evaluate reservoirs where the contrast between water salinity and hydrocarbon was low. However, by the early 1990s, the interest in this technology declined because of many wellbore environmental problems, such as borehole rugosity, that caused a lack of robustness in measurements compared to the first-generation dielectric tools.

DD tools operate in a similar fashion to electromagnetic propagation tools used to measure RES. The difference of phase and amplitude caused by the emitted and received electromagnetic waves allows for the calculation of the permittivity and the conductivity of the medium (Calvert and others, 1977; Rau and others, 1991). The difference is due to a combination of two effects: the permittivity and conductivity of the medium and the array of the receivers. Therefore, for a given permittivity and conductivity, a specific propagation loss will exist (Berry II and others, 1979).

New-generation tools utilizing DD technology provide several features specifically designed to overcome the shortcomings of previous tools (Hizem and others, 2008). The updated features include a new-style antenna array set on a fully articulated pad that is run in contact with the borehole wall, eliminating many environmental effects that hindered DD logging in the past. Multifrequency measurements allow for evaluation of the change in DD properties as a function of frequency. Inversion of DD data allows for the separation and quantification of the different effects influencing the dielectric measurement, such as water volume, water salinity, and rock texture (Archie parameters).

While most applications in the past have been for oil and gas, multifrequency DD also has relevance to carbon sequestration in saline aquifers. Direct formation water volumes and salinity are a crucial piece of information for subsurface modeling and regulatory compliance during the characterization phase prior to CO_2 injection. When coupled with other geophysical characterization technologies, such as nuclear magnetic resonance, water-filled pore volumes, salinity, and permeability, estimates can be combined for a more comprehensive storage reservoir assessment.

Applications

- Directly measure water volume independent of water RES.
- Solve for water salinity with water volume measurements.
- Evaluate petrophysical (Schlumberger, 2013; Baker Hughes, 2021).
- Measure rock texture from Archie *mn* exponent log for determining saturations beyond the invaded zone.

- Cation exchange capacity (CEC) to account for the effect of clay volume in siliciclastics (Schlumberger, 2013).
- Detect water-filled porosity in thin beds with robust measurements.
- Evaluate ultra-heavy hydrocarbons in low-RES waters (Herlinger Jr., 2019).
- Effectively measure water saturation and salinity in carbonates (Herlinger Jr., 2019).
- Evaluate Residual oil saturation in presalt wells (Herlinger Jr., 2019).
- CO_2, water, and chemical floods for enhanced oil recovery (EOR).
- Sequester CO_2.

Deployment Logistics

Operating Environment: Openhole, Downhole

Tool Limitations

- Accuracy at the highest frequency corresponding to 0.002-ft^3/ft^3 (0.002-m^3/m^3) water-filled porosity (Schlumberger, 2013).
- Determining water salinities in the range of 0 to 20,000 ppm is a limitation for standalone DD, however this is not a limitation of other DD applications or of joint determination of salinity in combination with other measurements.
- Permittivity ranging from 1 to 100 (Schlumberger, 2013).
- Conductivity ranging from 0.1 to 3000 mS (Schlumberger, 2013).
- Depth of investigation ranging from 1 to 4 inches.
- Frequencies ranging from 20 MHz to 1 GHz.
- Temperatures reaching 350°F (177°C) (Schlumberger, 2013).
- Borehole sizes ranging from 6 to 22 inches (Schlumberger, 2013).
- Water salinities higher than 20,000 ppm may require additional measurements such as formation Sigma and Cl^-.
- Cased-hole environments.

Sources of Error

- Salinity results can possibly be affected by the high conductivity of clay-bound water. Further work has been proposed to improve the salinity inversion in shale (Bean and others, 2013).

- Older-generation single-frequency dielectric propagation tools can be very sensitive to borehole rugosity.

- Accurate determination of formation water salinity in oil-based mud (OBM) may be limited depending on environmental factors (Bean and others, 2013). Adequate prejob planning is recommended to address any potential issues.

- In permeable formations, the possibility of invasion of drilling fluid into the zone of measurement must be determined and accounted for in the interpretation.

Lead Time Required to Deploy Technology

DD tools are commercially available through major oilfield service providers. Typically, services are selected during the initial planning stages of the drilling or logging program a few weeks to a few months before the estimated deployment date. Additionally, extensive prejob forward modeling and simulation work are recommended prior to deployment and data acquisition to evaluate the feasibility of successful data acquisition and processing.

Case Studies and Key Findings

Oil and gas operators in the United Arab Emirates have utilized DD technology to assess multiple CO_2 and/or water EOR projects located onshore Abu Dhabi. The dielectric, nuclear magnetic resonance (NMR), and conventional well log data were used to construct a volumetric petrophysical model and estimate different matrix and pore fluid components (Jibar and others, 2020). This approach enabled the operators to identify zones and layers with different reservoir quality, pore systems, permeability, and fluid saturation.

In Saudi Arabia, CO_2 flooding was used to recover additional oil left behind after waterflooding. Parameters such as lithology, porosity, salinity, and water saturation were needed to quantify remaining oil saturation (ROS) before and after CO_2 flooding (AlOtaibi and others, 2017). The dielectric tool provided measurements that were independent of salinity in the swept interval. The values were used to compare the result with water saturation calculated from induction RES to increase certainty and to help in selecting sampling points for the formation tester operation. The results in Figure 1 showed a reasonable agreement between the two results of RES and dielectric in both zones (1 and 2). Dielectric logging is gradually replacing NMR log-inject-log for ROS measurement, especially in the situations where connate and injected water salinities can be vastly different (Schmitt and others, 2011).

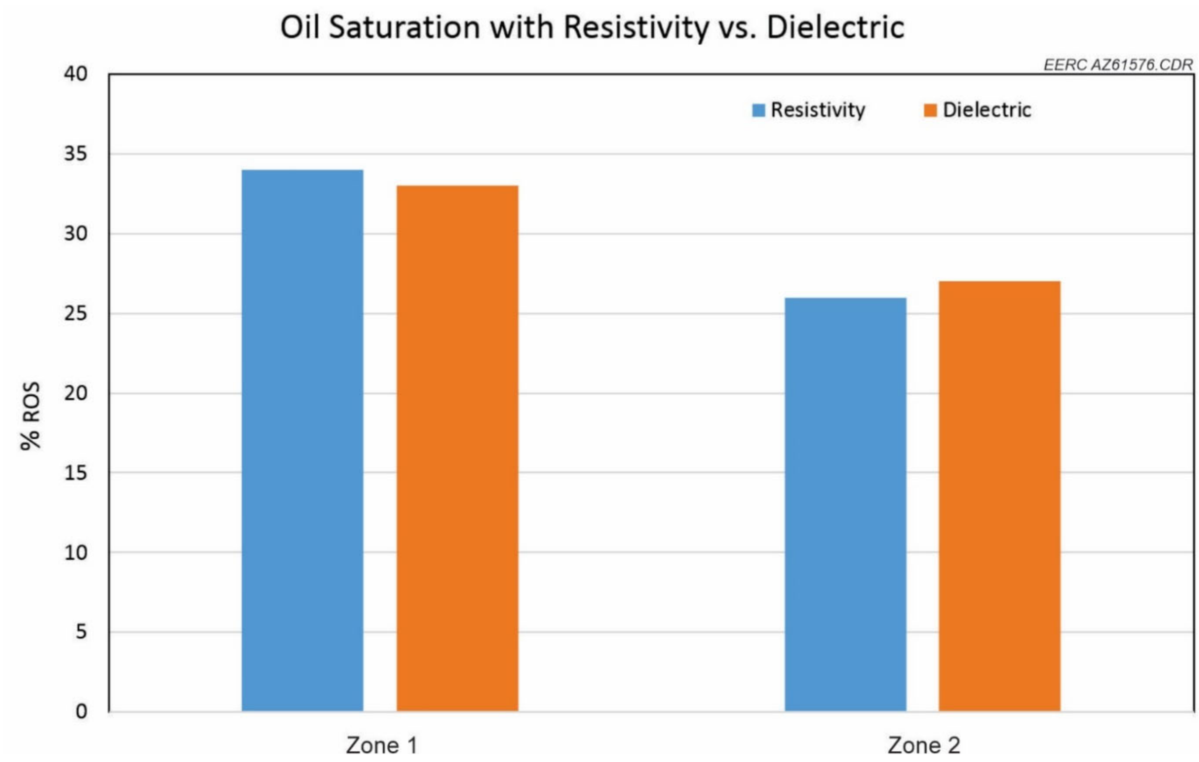

Figure 1. Results of ROS comparison between RES and dielectric measurements in Zones 1 and 2 prior to CO_2 EOR in oil fields previously waterflooded in Saudi Arabia (AlOtaibi and others, 2017).

Price Estimates

- Pricing is expected to be similar to that of advanced openhole geophysical technologies, such as NMR, capture spectroscopy, etc., and is expected to include prejob feasibility modeling and simulation, acquisition, equipment mobilization, and data processing.

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DISTRIBUTED FIBER OPTICS

Distributed fiber optics (DFOs) are deployed along the length of the borehole to monitor changes in pressure, temperature, acoustic energy, and chemical concentrations. Individual or multiple fibers can be wound in the same cable for downhole deployment. A wide array of applications to oil and gas exist, from hydraulic fracture monitoring to production and injection performance, and even reservoir characterization. There are also applications related to CCS, like monitoring CO_2 plume movement and measuring the aforementioned parameters associated with injection.

Distributed temperature systems (DTSs) are a relatively old technology used for temperature profiling behind casing. A new generation of fiber-optic sensors, such as distributed acoustic systems (DASs), distributed pressure systems (DPSs), distributed chemical systems (DCSs), and distributed strain systems (DSSs), are either commercially available or currently being developed (Koelman, 2011). Select service providers are able to map the location and orientation of DFOs as they are installed without the need for a subsequent wireline mapping run (Halliburton, 2020). Fiber-optic cables and distributed-fiber Bragg grating systems allow temperatures and other parameters, such as pressure, to be measured along the cable's length in contrast with point-by-point measurements, which utilize a network of individual temperatures and pressure sensors.

There are many field-proven applications to CO_2 sequestration and EOR. A few examples are shallow reservoir characterization, CO_2 plume tracking, and subsurface CO_2 leakage. Some possible applications that have not been validated are deep reservoir characterization and CO_2 plume tracking, surface CO_2 leakage, and well integrity issues associated with cement and/or corrosion. The key for future applications is to bundle a selection of fibers into a single cable suitable for downhole deployment and optimized for monitoring a variety of in situ data (Abdulaziz and others, 2021).

DISTRIBUTED TEMPERATURE SYSTEMS

DTSs measure temperature gradients along the length of a borehole. Distributed temperature sensing can be an important tool for analyzing where and how a CO_2 plume moves once injected into the subsurface (Soroush and others, 2021). The temperature profile can show which portion of the injection interval is actually injecting CO_2 and which parts are not (Halliburton, 2020a,b).

There are advantages to using distributed temperature systems compared to traditional temperature logging technologies, such as predicting sweep efficiency for a CO_2 EOR project; predicting the plume growth in a deep saline aquifer; and leakage monitoring, which is noninvasive to injection or other monitoring operations (Halliburton, 2020a,b). Sweep efficiency is the measure of the effectiveness of an EOR process that depends on the volume of the reservoir contacted by the injected fluids (Schlumberger, 2021).

Typical installations of DTS are permanent and use either a pump-down method in a preinstalled conduit or an installed, fixed cable (Jaaskelainen, 2009). However, DTS can alternatively be deployed postcementing on wireline, slickline, injection tubing, or coiled tubing in existing wellbores. DTSs, available through multiple oilfield service providers, are capable of operating as deep as 15,000 meters, with temperature resolutions of 0.1°F/°C or less (Weatherford, 2020) and can incorporate point pressure measurements and/or DASs. A single surface acquisition unit can be used to log data from multiple wells on a continuous cycle for large monitoring applications (Weatherford, 2020). Remote monitoring applications may also be applicable to DTS technology.

Applications

- Detect water or gas breakthrough (Weatherford, 2020).
- Measure distributed temperature (Weatherford, 2020; Schlumberger, 2017; Baker Hughes, 2021).
- Monitor water, steam, or gas injection performance (Weatherford, 2020).
- Assess cement quality by analyzing temperature data during curing process.
- Determine wellbore fluid production or injection rates (Weatherford, 2010).
- Locate perforated intervals.
- Identify well problems, such as flow behind casing, and detection of leaks, hydrates, asphaltenes, and paraffin (Weatherford, 2020; Hurter and others, 2007).
- Characterize production contribution of well zones or segments, including oil, water, and gas (Weatherford, 2020).

- Measure immediately after installation and throughout the life of the well without recalibration (Weatherford, 2020).

- Detect CO_2 leakage through sealing formations (Hurter and others, 2007; Freifeld, 2007).

- Monitor thermal perturbation, allowing differentiation between CO_2 and water (Freifeld, 2007).

- Analyze injection rates per perforated interval using thermal tracers.

- Determine fluid saturations (Freifeld, 2007).

- Use available technology. Temperature sensing is presently the predominant measurement employed in DTSs; however, multiple service providers offer the ability to detect acoustic energy, pressure, and strain measurements on the same fiber optic. Point sensors are also available that can be deployed on the same fiber-optic line as DTS.

Deployment Logistics

Operating Environment: Downhole, Cased Hole

Tool Limitations

- Analysis and interpretation, which require a good knowledge of the geologic and downhole environment, may be required (Johnson and others, 2006; Schlumberger, 2021).

- The fiber-optic cables installed permanently cannot be removed, modified, or repaired after installation.

- Mechanical damage to the cable can occur during installation.

- Technology is capable of sensing temperature only, unless pressure and distributed acoustic sensors are included with the deployment; applicability should be assessed prior to deployment. Thermal modeling of an injection scheme may be necessary to determine applicability.

- Point measurement DTSs require additional hardware.

- Thermal perturbation monitoring requires the additional installation of a linear heater.

Sources of Error

- Absorption and impurities within the fiber-optic and mechanical strain and/or damage can cause a reduction in light transmission causing measurement error (Liteway Inc., 2002).

- Misinterpretation of data may result in false dynamic assumptions about a reservoir or well.

- The DTS system operating wavelength band can be changed by the presence of hydrogen. The sensitivity to dynamic differential attenuation effects can, to some extent, be mitigated using specialized equipment and materials (Jaaskelainen, 2009).

- Mechanical and chemical exposure during installation can reduce the service life of a DTS system (Jaaskelainen, 2009).

Lead Time Required to Deploy Technology

DTSs are a specialized service that may not be available through all service providers. Typically, DTS services are selected during the initial planning of the well drilling and completion operations. Applicability and installation concerns should be discussed with the service provider in the planning stages of the project to ensure equipment and personnel availability during installation. There may be special requirements during casing and cementing operations, which must be communicated with the respective service providers performing these operations early in the planning stages. Wireline or coiled tubing postcementing deployments in existing wellbores require less coordination between service providers and, therefore, planning; however, market availability may require long lead times and should be discussed with service providers well in advance of deployment.

Case Studies and Key Findings

Nuñez-Lopez and others (2014) used DTS data to monitor temperature and CO_2 flow within injection zones as well as detection of CO_2 leakage to overburden in the U.S. Gulf Coast. The injection site had received more than 5 million metric tonnes of CO_2, and temperature measurements were acquired along two observation wells. Over 500-million temperature measurements were acquired during the study period from November 2009 through November 2010 and September 2011 to January 2012. Results indicated that DTSs can be a useful supporting tool when used in combination with pressure monitoring and imaging technologies.

Wiese (2014) correlated heat transfer and thermodynamic conditions to DTS data in Ketzin, Germany, in a CO_2 project. The DTSs data were separated into two categories: mean value and spatial derivation. The combination of the two allows determined heat transfer for all operational conditions along the entire well. The key takeaways from this project were to install the DTS cables with well-defined buckles, e.g., by way of centralizers, that would increase the accuracy of transferring the correlations between different well segments.

Mawalkar and others (2019) presented the results of real-time DTS and multilevel pressure data to monitor CO_2 migration into the reservoir in a CO_2 EOR project in northern Michigan. The DTSs data were analyzed during the initial injection of ~101,000 metric tonnes of CO_2 during January 2017 and December 2018. They used warmback analysis to determine where CO_2 enters into the reservoir as well as to monitor its vertical migration. Relatively quick warmback periods above and below the perforated intervals indicated that CO_2 did not migrate outside of the target formations. DTSs were also able to detect the CO_2 front at the monitoring well in conjunction with pressure, gas saturation, and wireline temperature logging.

Richard and Pevzner (2018) used DTS data to monitor the location of thermal anomalies for a range of Australian CCS research projects. Temperature measurements were acquired from wellhead to bottomhole for 13 days. The setup was capable of detecting a 0.7°C anomaly very quickly and a 0.1°C anomaly after data processing. The experiment showed promising prospects for DTSs in the context of monitoring, cost reduction, and detection of events that enable informed decision-making.

Johnson and others (2006) conducted a study that coupled DTS and temperature–pressure simulations to determine flow profiles from multilayered reservoirs in production gas wells in order to gain a better understanding of the thermodynamic conditions within each layer of the reservoir. The study found that DTS can be successfully and practically used for evaluating the flow contributions of individual production or injection zones. They also found that it is very important to know the local geothermal gradient for decreasing the uncertainties of DTS temperature-based flow rate calculations (Johnson and others, 2006).

Carbon dioxide and DTSs have been studied by Hurter and others (2007), who examined the suitability of DTS systems to monitor the fate of injected CO_2. The bulk thermal conductivity of porous rocks saturated with water or brine decreases as CO_2 concentrations increase within a reservoir (Hurter and others, 2007). The study found that CO_2 leakage and saturation in storage reservoirs can be successfully monitored using DTS systems.

Freifeld (2007) investigated the applicability of DTS and thermal perturbation sensors for CO_2 geologic sequestration, including vertical distribution of CO_2 and leakage into cap rock or around a casing. The study concluded that it is possible to detect CO_2 distributions/saturations and leakage using DTS because of the variances in thermal properties associated with CO_2 saturation.

Price Estimates

- Permanently installed casing containing DTS and pressure sensors (high)
- Coiled tubing or wireline deployments in existing wellbore (low; per run)

DISTRIBUTED ACOUSTIC SYSTEMS

Distributed acoustic systems (DASs) turn a standard telecom fiber deployed over an entire well path into a permanent array of microphones. The sound waves registered by the array reveal CO_2 flow patterns, which can provide valuable insight for plume monitoring or possible well integrity issues with cement bond to the casing. Also, downhole acquisition through DASs are inherently simpler and safer than acquisition with geophones (Koelman, 2011).

Rapid development has occurred in instrumentations, sensing cables, and general application to seismic exploration. DASs record seismic energy; such receivers have a certain directivity pattern in which they are more sensitive to seismic waves propagating along the cable axis compared to energy arriving broadside (Correa and others, 2017). Baseline seismic surveys coupled with precise measurements from DASs can be a cost-effective solution when it comes to detecting and remediating CO_2 leakage along the wellbore.

Installations of DASs are commonly permanent and use either a pump-down method in a preinstalled conduit or an installed, fixed cable (Jaaskelainen, 2009). However, DASs can, alternatively, be deployed postcementing on wireline, slickline, or coiled tubing in existing wellbores. Multiple service providers offer DASs that are capable of operating as deep as 32,000 feet (Schlumberger, 2016) and can incorporate point pressure measurements and/or DTSs. A surface acquisition unit can monitor multiple wells simultaneously (Schlumberger, 2018, Weatherford, 2020). Remote monitoring applications are also available and applicable to DASs.

Applications

- Monitor injections so that injectate reaches intended zones. Detection of gas breakthrough (Weatherford, 2020).
- Distribute acoustic measurements (Weatherford, 2020; Schlumberger, 2016; Baker Hughes, 2021a,b; Halliburton, 2017).
- Monitor water, steam, or gas injection performance (Weatherford, 2020).
- Assess cement quality by detecting CO_2 leakage paths.
- Determine wellbore fluid production or injection rates (Weatherford, 2010).
- Locate perforated intervals.
- Identify well problems, such as flow behind casing and detection of leaks, hydrates, asphaltenes, and paraffin (Weatherford, 2020; Hurter and others, 2007).
- Characterize production contribution of well zones or segments, including oil, water, and gas (Weatherford, 2020).

- Measure immediately after installation and throughout the life of the well without recalibration (Weatherford, 2020).

- Identify available technology. Acoustic energy is the main source of data acquired through DASs. However, geophones are also available that can be deployed with similar spacing along the wellbore.

Deployment Logistics

Operating Environment: Downhole, Cased Hole

Tool Limitations

- Analysis and interpretation, which require a good knowledge of the geologic and downhole environment, may be required (Johnson and others, 2006; Schlumberger, 2021).

- The fiber-optic cables installed permanently cannot be removed, modified, or repaired after installation.

- Mechanical damage to the cable can occur during installation.

- Installation of source vibrators or dynamite charges along with a vertical seismic profile (VSP) survey is necessary for acoustic coupling with DASs.

- Technology is capable of sensing acoustic energy only, unless pressure and distributed acoustic sensors are included with the deployment; applicability should be assessed prior to deployment. Seismic and acoustic velocity interpretation of an injection scheme may be necessary to determine applicability.

Sources of Error

- Injection tubing can cause vibrations during the acquisition of the VSP (due to dynamite or vibroseis energy waves impacting the tubing string), which adversely affects the acquired DAS data (Kelley and others, 2020).

- Misinterpretation of data may result in false dynamic assumptions about a reservoir or well.

- Mechanical and chemical exposure during installation can reduce the service life of a DAS (Jaaskelainen, 2009).

- Acoustic energy generated from dynamite can be weaker when compared to those generated from vibrators with applications to VSP DASs.

Lead Time Required to Deploy Technology

DASs are a specialized service that may not be available through all service providers. Typically, DAS services are selected during the initial planning of the well drilling and completion operations. Applicability and installation concerns should be discussed with the service provider in the planning stages of the project to ensure equipment and personnel availability during installation. There may be special requirements during casing and cementing operations that must be communicated with the respective service providers performing these operations early in the planning stages. Wireline or coiled tubing postcementing deployments in existing wellbores require less coordination between service providers and, therefore, planning; however, market availability may require long lead times and should be discussed with service providers well in advance of deployment.

Case Studies and Key Findings

The South West Hub In-Situ Laboratory in Western Australia performed experiments focusing on the controlled release of a small amount of CO_2 into a shallow fault zone, monitoring evolution and movements of the plume. The project's focus is on studying the impact of faulting on carbon dioxide migration patterns in shallow geologic conditions and designing the monitoring approach for early detection and monitoring of a potential out-of-storage CO_2 leakage. The primary method for monitoring was a combination of VSP and DASs. The results suggest that the downhole seismic (DS) using a combination of inexpensive and scalable DASs and small sources provides a reliable and cost-effective surveillance solution for early warnings in the event of unwanted leakage of gas from a CO_2 reservoir (Tertyshnikov and others, 2019).

A project in Michigan aimed to assess the effectiveness of DAS-based VSP technology for delineating CO_2 injected into Silurian-age pinnacle reefs. a time-lapse DAS VSP was implemented at the Chester 16 reef to detect approximately 85,000 tonnes of CO_2 injected into the formations. This DAS VSP study was partially successful for detecting CO_2 injected into the Chester 16 pinnacle reef. For DAS VSP technology to clearly detect the injected CO_2, the injected fluid must cause a change in acoustic impedance (velocity and/or density) large enough to cause a change in reflection coefficient that can be visibly detected (Kelley and others, 2020).

Price Estimates

- Permanently installed casing containing DASs and pressure sensors (high)
- Coiled tubing or wireline deployments in existing wellbore, (low; per run)

DISTRIBUTED PRESSURE SYSTEMS

Distributed pressure systems (DPSs) measure pressure gradients along the length of a borehole at locations where sensors are placed. Pressure is one of the most important downhole measurements, and flow can be directly calculated from pressure with high confidence (Smart Fibres, 2018). The pressure profile can show which zones are receiving CO_2 injection and optimizing operations during EOR.

Direct pressure exposure induces changes in the optical fiber properties in different ways by modifying the index of refraction, inducing strain along the direction of light propagation, and modifying wavelength dispersion (Hocker, 1979). Advancements in materials and protective coatings have increased the resistance to electromagnetic interference and chemicals (Aoms, 2019).

Typical installations of DPSs are permanent and use either a pump-down method in a preinstalled conduit or an installed, fixed cable (Jaaskelainen, 2009). DPSs are available through oilfield service providers and are capable of operating in pressure environments as high as 20,000 psi, with pressure resolutions of <0.005% of full scale (Smart Fibres, 2018) and can incorporate point pressure measurements and/or DTSs. A single surface acquisition unit can be used to log data and transfer to other well surveillance systems.

Applications

- Improve reservoir modeling (Smart Fibres, 2018).
- Distribute pressure measurements (Smart Fibres, 2018).
- Monitor water, steam, or gas injection performance (Weatherford, 2020b).
- Determine wellbore fluid production or injection rates (Weatherford, 2020a).
- Locate perforated intervals.
- Measure immediately after installation and throughout the life of the well without recalibration (Weatherford, 2020b).
- Identify available technology. Pressure sensing is presently the predominant measurement employed in DPSs. Point sensors are also available that can be deployed on the same fiber-optic line as DPSs.

Deployment Logistics

Operating Environment: Downhole, Cased Hole

Tool Limitations

- Analysis and interpretation, which require a good knowledge of the geologic and downhole environment, may be required (Johnson and others, 2006; Schlumberger, 2021).

- The fiber-optic cables installed on behind casing are permanent and cannot be removed, modified, or repaired after installation.

- Mechanical damage to the cable can occur during installation.

- Technology is capable of sensing pressure only, unless temperature and distributed acoustic sensors are included with the deployment; applicability should be assessed prior to deployment.

- Multizone/point measurements in multilateral wells.

- Sensing in deep high-pressure/temperature wells.

Sources of Error

- Absorption and impurities within the fiber-optic and mechanical strain and/or damage can cause a reduction in light transmission causing measurement error (Liteway Inc., 2002).

- Misinterpretation of data may result in false dynamic assumptions about a reservoir or well.

- Unfortunately, uncoated optical fibers are almost insensitive to hydrostatic pressure and, therefore, its direct measurement by merely exposing the fiber to the pressure field cannot achieve high sensitivity (Budiansky, 1979; Rogers, 1988).

- Mechanical and chemical exposure during installation can reduce the service life of a DPS system (Jaaskelainen, 2009).

Lead Time Required to Deploy Technology

DPSs are a specialized service that may not be available through all service providers. Typically, DPS services are selected during the initial planning of the well drilling and completion operations. Applicability and installation concerns should be discussed with the service provider in the planning stages of the project to ensure equipment and personnel availability during installation. Special requirements may exist during casing and cementing operations that must be communicated with the respective service providers performing these operations early in the planning stages. Wireline or coiled tubing postcementing deployments in existing wellbores require less coordination between service providers and, therefore, planning; however, market availability may require long lead times and should be discussed with service providers well in advance of deployment.

Case Studies and Key Findings

Shell utilized a permanent fiber-optic, wellbore-fluid-level monitoring system that consisted of DPSs and DTSs for an oil and gas well it operates in Oman. Multiple fluid contacts were successfully monitored and observed. The system provided real-time data to the reservoir engineers, informing their production optimization decisions and delivering significant value (Staveley and others, 2017). Even though the project focused on oil, water, and gas contacts, applications exist to other fluids, such as CO_2/brine or CO_2/oil. The initial deployment was under a final trial development phase, which progressed the technology to commercially supply multiple well systems soon after acquiring the first data set.

Price Estimates

- Permanently installed casing containing DPS and pressure sensors (high)
- Coiled tubing or wireline deployments in existing wellbore (low; per run)

DISTRIBUTED CHEMICAL SYSTEMS

Depending on the coating, distributed chemical systems (DCSs) are capable of detecting various molecules in diverse media under extreme conditions. Different coatings may change color in the presence of certain molecules. For example, a segment of fiber exposed to air may be purple, but in the presence of CO_2 it changes to orange. Distributed chemical sensing can be an important tool for monitoring groundwater and the vadose zone during CO_2 injection. The chemical changes observed can show where CO_2 leakage is occurring and possible migration paths.

There are advantages to using DCSs compared to traditional methods, which apply a more direct analysis of groundwater (sampling followed by laboratory analysis) or in the vadose zone, where chemical sensors monitor gas flux in only one location, are not cost effective for large areas or long-term monitoring (IOS, 2021). If a gas is leaking between sampling and lab analysis periods, then it would be difficult to ascertain exactly when the leak started. Employing DCSs should mitigate issues and assumptions associated with directly sampling and analyzing sources of drinking water.

DCSs are not yet commercially available in the oil and gas industry, but testing has shown that it can provide reversible detection of H_2O, CO_2, and H_2S molecules (TNO, 2013). Remote monitoring applications may also be applicable to DCS technology.

Applications

- Use distributed chemical measurements (TNO, 2013; IOS, 2021).
- Monitor freshwater zones (IOS, 2021).
- Detect changes in reservoir chemistry and migration of fluid contacts.
- Characterize production contribution of well zones or segments, including oil, water, and gas (TNO, 2013).
- Detect CO_2 leakage through sealing formations (IOS, 2021).

Deployment Logistics

Operating Environment: Downhole, Cased Hole

Tool Limitations

- Analysis and interpretation, which require a good knowledge of the geologic and downhole environment, may be required (Johnson and others, 2006; Schlumberger, 2021).
- The fiber-optic cables installed permanently cannot be removed, modified, or repaired after installation.

- Mechanical damage to the cable can occur during installation.

- Technology is capable of sensing molecules and chemical composition only, applicability should be assessed prior to deployment. Chemical and pressure–volume–temperature (PVT) modeling of an injection scheme may be necessary to determine applicability.

Sources of Error

- Absorption and impurities within the fiber-optic and mechanical strain and/or damage can cause a reduction in light transmission causing measurement error (Liteway Inc., 2002).

- Misinterpretation of data may result in false dynamic assumptions about a reservoir or well.

- Chemically induced refractive index (RI) changes may break the light guidance condition, leading to optical power variations (Lu and others, 2019).

Lead Time Required to Deploy Technology

DCSs are not yet a commercial technology in the oil and gas industry and, as such, any trial would need significant lead time.

Case Studies and Key Findings

A field demonstration of CO_2 leakage detection was conducted with a pulse-like CO_2-release test in a shallow aquifer (IOS, 2021). The water chemistry parameters that were monitored included alkalinity, pH, and dissolved inorganic carbon (DIC). These were analyzed by obtaining periodic groundwater samples and a fiber-optic CO_2 sensor for the real-time in situ monitoring. Measurements taken with the fiber-optic CO_2 sensor displayed obvious signals of leakage, demonstrating the potential of real-time in situ monitoring of dissolved CO_2 for leakage detection at a geologic carbon sequestration site. Water sample measurements of groundwater pH, alkalinity, DIC, and dissolved CO_2 clearly deviated from their baseline values, showing CO_2 leakage. While both methods were successful in detecting each controlled CO_2 release, the fiber-optic CO_2 sensor is the only method capable of providing real-time in situ data opposed to periodic water sample.

Price Estimates

- Unknown, but likely quite high as the technology is not commercially available.

DISTRIBUTED STRAIN SYSTEMS

Distributed strain systems (DSSs) detect strain variation events along the entire length of the wellbore. Analyzing these events over an elapsed time can quickly pinpoint well integrity issues, pressure responses, and flow rates. Distributed strain sensing can be an important tool for analyzing mechanical stresses induced on well equipment during CO_2 injection. Instances of tubular buckling or burst can be visualized through strain measurements (Pearce and others, 2009).

The advantages of using DSSs compared to other DFOs and logging technologies is the knowledge that the structural integrity of the well is being continuously monitored. An alarm or warning is automatically sent whenever preset measurement values are reached (Inventec, 2021). Deformations registered in environments adjacent to the fiber-optic cable can also be translated into pressure and flow readings.

Typical installations of DSSs are permanent and use either a pump-down method in a preinstalled conduit or an installed, fixed cable (Jaaskelainen, 2009). DSSs are available through multiple technology providers and can measure strain at ±2500 με and have a common fatigue life of $>1\times10^8$ cycles at ±2000 με (Luna, 2019). A single surface acquisition unit can be used to log data from multiple wells on a continuous cycle for large monitoring applications (Luna, 2019). Remote monitoring applications may also be applicable to DSS technology.

Applications

- Detect deformations and stress changes adjacent to the wellbore.
- Convert strain measurements to pressure and flow rate.
- Identify distributed strain measurements (Luna, 2019; OFS, 2017).
- Detect induced fractures from a monitoring location (Jin and others, 2021).
- Locate perforated intervals.
- Recognize areas of depletion within the reservoir.
- Constrain near-wellbore fracture networks to better understand production or injection performance (Jin and others, 2021).
- Use available technology. Strain sensing is presently the predominant measurement employed in DSSs. Point sensors are also available that can be deployed on the same fiber-optic line as DSS.

Deployment Logistics

Operating Environment: Downhole, Cased Hole

Tool Limitations

- Analysis and interpretation, which require a good knowledge of the geologic and downhole environment, may be required (Johnson and others, 2006; Schlumberger, 2021).

- The fiber-optic cables installed permanently cannot be removed, modified, or repaired after installation.

- Mechanical damage to the cable can occur during installation.

- Technology is capable of sensing strain only, unless pressure and distributed acoustic sensors are included with the deployment; applicability should be assessed prior to deployment.

- Point measurement DSSs require additional hardware.

Sources of Error

- Absorption and impurities within the fiber-optic and mechanical strain and/or damage can cause a reduction in light transmission causing measurement error (Liteway Inc., 2002).

- Misinterpretation of data may result in false dynamic assumptions about a reservoir or well.

- The Brillouin frequency shift depends on the material composition and, to some extent, the temperature and pressure of the medium (Hveding and others, 2018).

- Light scattering, such as Rayleigh band and Stokes Raman, is not affected by strain (Hveding and others, 2018).

- DSSs have higher spatial resolution but lower temporal resolution compared to DAS measurements (Jin and others, 2021).

Lead Time Required to Deploy Technology

DSSs are a specialized service that may not be available through all service providers. Typically, DSS services are selected during the initial planning of the well drilling and completion operations. Applicability and installation concerns should be discussed with the service provider in the planning stages of the project to ensure equipment and personnel availability during installation. There may be special requirements during casing and cementing operations that must be communicated with the respective service providers performing these operations early in the planning stages. Wireline or coiled tubing postcementing deployments in existing wellbores require less coordination between service providers and, therefore, planning; however, market availability may require long lead times and should be discussed with service providers well in advance of deployment.

Case Studies and Key Findings

Fiber-optic-based DSS Rayleigh frequency shift methods were used to evaluate near-wellbore fracture characteristics (Jin and others, 2021). Strain variations along the borehole were shown to be related to borehole pressure changes at each perforation cluster with high spatial resolution and temporal sampling rates during shut-in and reopening well operations. Importantly, significant differences were observed for the two different types of stimulation completion designs of the monitored well. The time-dependent relation between borehole pressure and strain change provided important insights into the near-wellbore fracture network. These insights can be directly applied to CO_2 injection and monitoring changes in the near-wellbore and far-field conditions.

A fiber-optic strain-imaging tool was able to quantify in real-time, with high spatial resolution and accuracy, the detailed change in the pipe shape as it deforms through the use of thousands of FBG (fiber Bragg grating) strain sensors on a single joint of pipe (Pearce and others, 2009). The results were displayed in a series of laboratory, shop, and field-scale tests. The shape of the tested pipe was interpreted as it underwent various modes of deformation: tension/compression, bending, and ovalization.

Price Estimates

- Permanently installed casing containing DSS and pressure/temperature sensors (high)
- Coiled tubing or wireline deployments in existing wellbore (low; per run)

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Downhole fluid sampling, temperature, and pressure testing (DSTP) is similar in application to in situ sampling and testing technologies. DSTP is primarily suited for, and most cost-effective as, a monitoring technology but has limited application for characterization in terms of baseline pressure and temperature measurements and geochemical analysis. DSTP consists of installed pressure or temperature transducers or fluid-sampling equipment either inside a wellbore or cemented with the casing in order to create a permanent or semipermanent well-testing system during initial well completions.

Both novel and commercial DSTP technologies have applications to CO_2 storage projects. The novel U-tube technology is an example of a permanently or semipermanently installed downhole fluid sampling device deployed in a wellbore to provide the ability to periodically acquire fluid samples (Freifeld and others, 2009; Jenkins and others 2012). In the case of the U-tube, nitrogen is used to push the fluid to the surface for sampling (Figure 2). Similar technologies have been developed and commercialized for the oil and gas industry and are sometimes referred to as a "smart casing" or "smart completion" technology, which can also include a multitude of pressure, temperature, distributed temperature, flow measurement, and flow control devices.

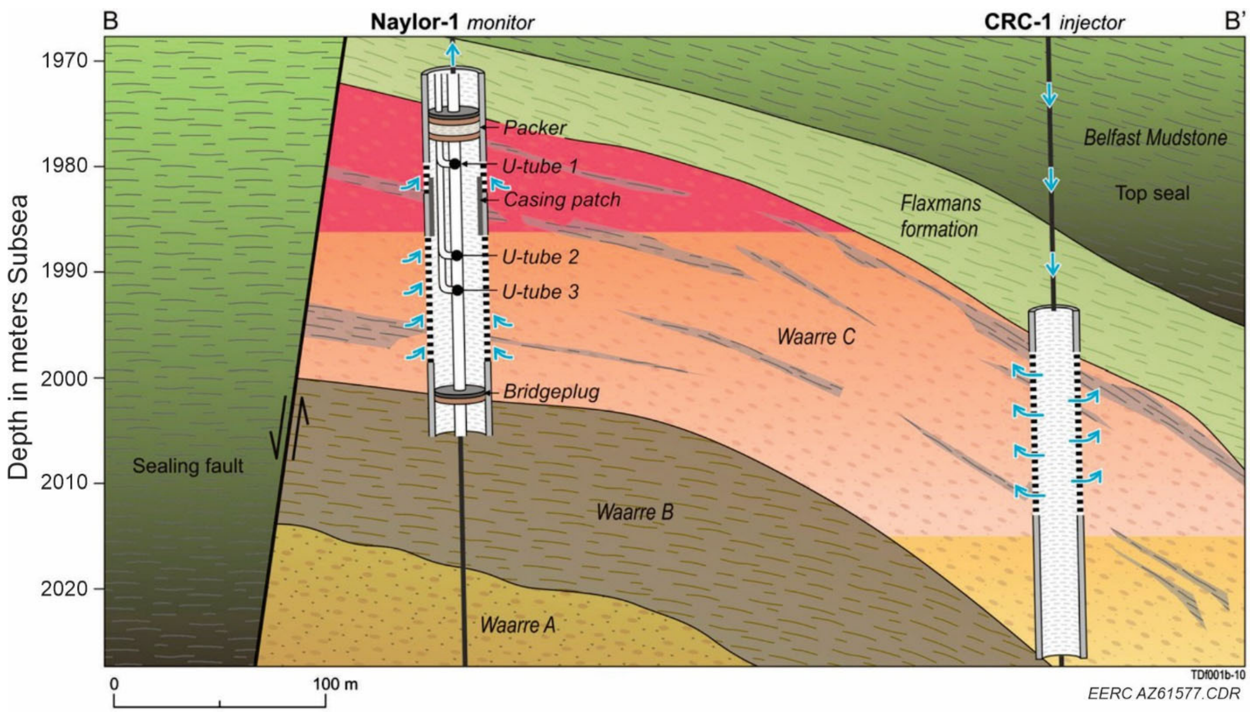

Figure 2. Schematic of the BHA at the Naylor-1 monitoring well indicating wellbore perforations and U-tube inlets. U-tube 1 accesses the free gas cap (red) through leaks in a casing patch, installed during production. U-tubes 2 and 3 are capable of collecting water samples from the light orange zone (Jenkins and others, 2012).

Downhole temperature and pressure measurement devices are utilized in the oil and gas industry as either permanent downhole monitoring systems to provide real-time continuous reservoir and production monitoring systems or through temporary deployment on wireline, slickline, or coiled tubing for well testing and other applications (Schlumberger, 2018). Fluid-sampling systems are also commonly paired with tracer injection to detect out-of-zone leakage and analyze how injected fluid moves through a reservoir. These same devices may prove beneficial for CO_2 injection monitoring and storage activities. Remote monitoring capabilities further increase the utility of the technology.

Applications

- Conduct pressure monitoring and pressure buildup surveys (Environmental Protection Agency, 2004; Schlumberger, 2018; Halliburton, 2020).

- Determine the arrival time of a CO_2 plume front to capture and record geochemical changes as the plume passes by the observation borehole (Freifeld and others, 2005).

- Determine CO_2 and other fluid saturations.

- Perform long-term groundwater, well, and formation integrity monitoring, including trace analysis (Schlumberger, 2018).

- Identify out-of-zone leakage or pressure communication.

- Assist with a fault or fracture analysis.

- Identify loss of injectivity.

- Provide baseline measurement data for monitoring program.

- Provide history-matching data and identify any deviation from an expected performance, which may require further investigation or remediation.

- Detect casing damage and assess zonal isolation issues.

Deployment Logistics

Operating Environment: Cased Hole

Tool Limitations

- Technology requires borehole penetration of the zone in which measurements are needed.

- A new borehole may be required to install technologies that do not interfere with normal operations within the wellbore.

- Physical and cost limitations on the number of zones that can be sampled or measured.
- Fluid sampling requires on-site personnel during sampling procedures.
- On-site fluid analysis is not currently integrated with commercially available sampling systems.
- The plume extent cannot be tracked other than identifying when the plume front passes an observation well or when pressure communication occurs.
- Optimizing the location of monitoring wells requires accurate modeling and simulation activities.
- Hydrate formation and freezing may hinder sampling operations.
- Fluid samples must be purged in order to obtain a representative sample, which reduces the volume of fluid recoverable during a single sampling operation (Freifeld and Trautz, 2006).

Sources of Error

- Full geochemical analysis of all fluids introduced during the wellbore completion process is necessary in order to accurately evaluate fluid samples and to identify fluid contamination and/or interactions with the samples of downhole fluids (Freifeld and Trautz, 2006).
- Fluid sampling requires the use of pressurized sample chambers to more accurately replicate in situ conditions. While sampling methodologies can be developed to prevent a pressure drop from formation pressure until analysis is performed, it is necessary to overpressure the fluid during sampling operations (sometimes significantly in deep reservoirs).
- Fluid samples may undergo temperature changes during and after sampling operations.
- Fluid samples contaminated with drilling fluids during sampling operations may be difficult to detect prior to laboratory analysis.

Lead Time Required to Deploy Technology

DSTP systems are considered a specialized technology and may not be available from all oilfield service providers. Extensive prejob modeling and simulation work may be necessary in order to optimize well placement, and remote monitoring may require third-party integration.

Typically, DSTP services are selected during the initial planning of the well drilling and completion operations. Applicability and installation should be discussed with a service company representative in the planning stages of the project to ensure equipment and personnel availability during installation. There may be special requirements during casing and cementing operations, which must be communicated with the respective service providers performing these operations in the planning stages.

Case Studies and Key Findings

The CO_2CRC Otway Project in southeastern Australia installed permanent gauges in the CRC-1 (Stage 1) and CRC-2 (Stage 2) injection wells and a complex BHA, including a U-tube sampler, in the Naylor-1 monitoring well. Approximately 150 days after the start of injection, arrival of CO_2 and chemical tracers injected into the CRC-1 well were observed at U-Tube 2 installed in the Naylor-1 monitoring well. Water samples collected from the U-tube sampler showed the pH decreasing sharply with increasing CO_2 content (Jenkins and others, 2012). The movement of fluid interfaces between fluids of differential densities injected in the well were determined by using multiple downhole pressure gauges. By placing the gauges across the perforations, the amount of contact a fluid has with the perforations could be monitored, which can be used as an input for reservoir simulations to determine sweep efficiency (Paterson and others, 2016). The study also demonstrated the reliability and stability of the gauges over several years with continuous, high-frequency pressure and temperature recordings.

A study conducted at the Frio Field east of Houston, Texas, involving CO_2 injection into a brine-saturated sandstone evaluated fluid samples from a U-tube sampler during the injection phase of the project (Hovorka and others, 2004). Gas-soluble tracers, as well as gas and aqueous chemistry analytical methods, were employed. The study successfully utilized a U-tube sampler, a novel mechanism, to obtain high-frequency, minimally altered samples of two-phase fluids in the wellbore during injection.

Price Estimates

- Smart casing pressure, temperature, and distributed thermal (high)
- Smart casing dual-zone fluid sampling (high)
- Downhole pressure and temperature deployment within wellbore (low) (Environmental Protection Agency, 2004)

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ELECTRICAL BOREHOLE IMAGING

Electrical borehole imaging (EBI) is based on dipmeter technology that has been commercially available since the 1950s. EBI tools use an array of electrodes on pads that are pressed against the borehole wall. The tool sends an electrical current into the formation, and the resulting measured electrical potential between each electrode can produce a RES map of the borehole walls when combined with caliper, accelerometer, and magnetometer readings (Asquith and Krygowski, 2004).

During processing, borehole images are created by assigning a color map to different ranges of RES values (Figure 3). Inherently low-RES features, such as shale or fluid-filled fractures, are displayed as dark colors, while high-RES features, such as nonporous rock, are displayed in shades of brown and yellow, with the highest RES appearing as white. Borehole images are best used in combination with cores, other well logs, and reservoir information to aid and enhance reservoir interpretation (Asquith and Krygowski, 2004).

Many analyses or interpretations produced from EBI require additional information, such as porosity, sonic (SON), RES, and GR logs; knowledge of local geology; and core analysis to produce accurate results. Therefore, it is necessary to thoroughly discuss the types of supplementary data required for the specific type of analysis or interpretation desired with the service company representative during the planning stages of the project (Baker Hughes, 2021c).

Applications

- Structural geology, such as detection, identification, classification, analysis, and orientation of faults; healed, open, drilling-induced; and natural fractures systems, including determination of fracture density and fracture aperture (Asquith and Krygowski, 2004; Baker Hughes, 2021c; Schlumberger, 2013) (Figure 4).

- High-resolution quantified imaging in boreholes with nonconductive fluids and OBM (Weatherford, 2017b; Schlumberger, 2014; Halliburton, 2021; Baker Hughes, 2021a,b).

- Complement to coring and formation testing programs through depth matching and orientation for whole cores, reservoir description for intervals not cored, information about the reservoir before core analysis is available, depth matching and orientation for sidewall core samples, and modular dynamics tester (MDT) probe settings (Schlumberger, 2013; Baker Hughes, 2021c) (Figure 5).

- Interpreting stratigraphy, such as bedding dip and strike (Asquith and Krygowski, 2004).

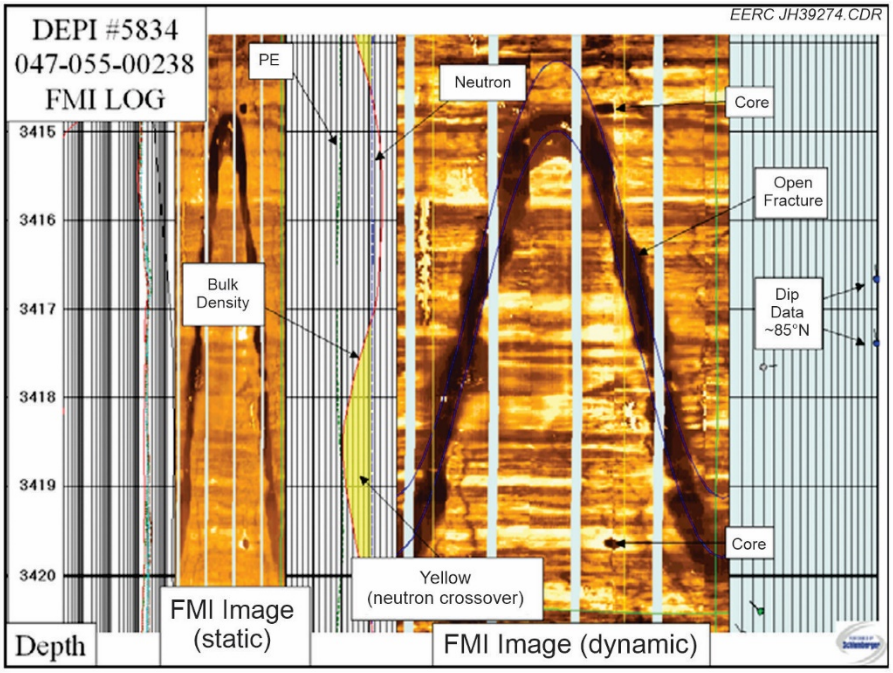

Figure 3. An EBI log example showing a 5-foot-long open fracture or fault (Edmonds, 2004).

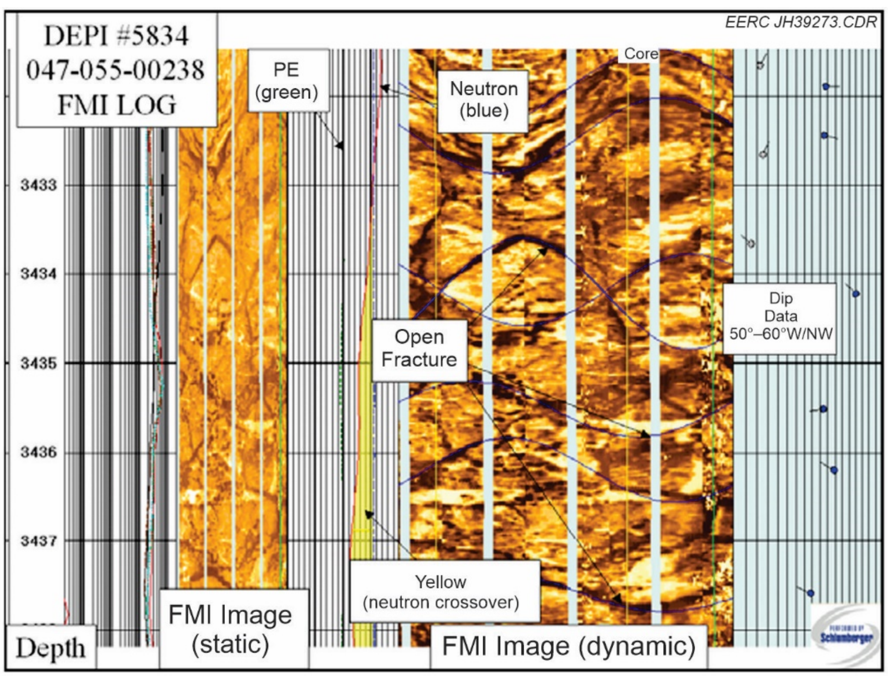

Figure 4. An EBI log example showing a fracture intensity of two fractures per foot (Edmonds, 2004).

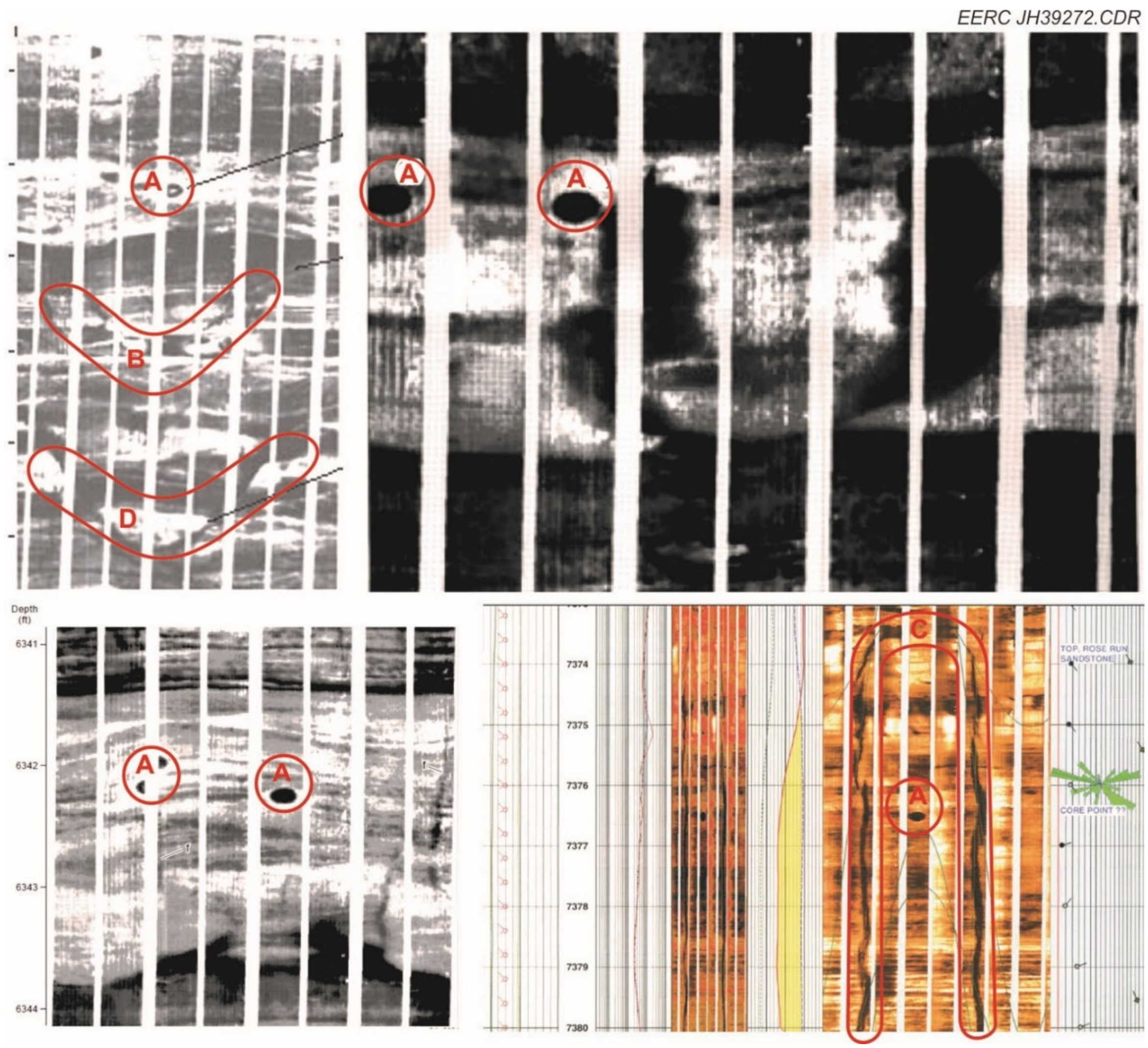

Figure 5. Multiple images of EBI logs, which illustrate a) the location and orientation of sidewall core samples taken on a previous run, b) an open natural fracture, c) a drilling-induced vertical fracture, and d) a small fault (Hardage and others, 1998; Riley and others, 2008).

- Interpretation of sedimentary structure (features such as burrows, clasts, vugs, and breccias) (Asquith and Krygowski, 2004).
- Analysis of sediment and deposition, such as dip, paleocurrent directions, paleotransport direction, characterization of depositional environment, facies description, definition and characterization of sedimentary bodies and their boundaries, recognition of anisotropy, permeability barriers, permeability paths, and recognition and evaluation of thinly bedded reservoirs (Schlumberger, 2007; Asquith and Krygowski, 2004).
- Analysis of rock texture, such as qualitative vertical grain-size profile, carbonate texture, and detection and evaluation of secondary porosity (Schlumberger, 2007).

- Compartmentalizing and analyzing permeability and directional permeability (Schlumberger, 2007; Asquith and Krygowski, 2004).

- Identifying and analyzing geomechanics drilling-induced fractures and mud weight selection.

- Interpreting in situ stress from borehole breakouts (pad caliper measurements) (Asquith and others, 2004).

- Detecting and measuring features too small for conventional logs. Vertical resolutions can be 0.2 inches or less (Schlumberger, 2007).

Deployment Logistics

Operating Environment: Openhole, Downhole

Tool Limitations

- Requires inclinometry data to be acquired simultaneously in order to orient the images for interpretation.

- EBI must be run sequentially after obtaining whole core to locate and orient sidewall cores in the same interval. If only utilizing sidewall cores, EBI should be run prior to assisting in the selection of representative coring points in the zone of interest.

- Areal coverage of the borehole is a function of the width of electrode arrays, number of pads, and the borehole diameter. In general, 40%–80% of the borehole face is imaged in typical boreholes (Asquith and Krygowski, 2004; Schlumberger, 2007). To increase borehole coverage, multiple logs can be conducted over the same interval and later combined through processing, or multiple tools, which are azimuthally offset, can be deployed on the same tool string.

- Because of the high-resolution data and large data bandwidth, logging speeds are typically run at approximately 1800 ft/hr (Asquith and Krygowski, 2004).

- Mud resistivities above 50 ohm-m are unsuitable for most electrical borehole images, although commercial tools are now available that are suitable for operation in high-RES mud systems (Weatherford, 2017a; Schlumberger, 2013; Baker Hughes, 2021c; Asquith and Krygowski, 2004).

- Ideal condition for EBI acquisition is a ratio between formation and mud RES of less than 1000 (Weatherford, 2017a; Schlumberger, 2013; Baker Hughes, 2021c; Asquith and Krygowski, 2004).

- EBIs can only be acquired in an openhole environment.

- Increased technological capabilities have resulted in tools capable of providing the same resolution in boreholes with either OBM or water-based mud.

- EBI produces a surface image of the borehole wall only. The depth of investigation is shallow to nonexistent, <1 to 3.5 inches (Weatherford, 2017a; Schlumberger, 2013; Baker Hughes, 2021c).

Sources of Error

- EBI tools are pad-type tools that are sensitive to borehole rugosity. Poor pad contact with the borehole wall leads to poor or nonexistent data quality.

- Pad pressure plays a role in data quality; however, this is controlled by the on-site service company representative. Any areas of lost circulation, large known washouts, or other hole problems should be discussed prior to operations with the on-site service company representative prior to logging.

- Tool sticking may drastically affect data quality or lead to gaps in data.

- Buildup of hydrocarbons and waxes on the pads may lead to poor data quality for certain tool types (Weatherford, 2017a; Schlumberger, 2013; Baker Hughes, 2021c).

- Shale-filled fractures can appear as open fractures (Asquith and Krygowski, 2004).

- Drilling-induced fractures may be difficult to distinguish from natural fractures.

Lead Time Required to Deploy Technology

EBI is not considered a standard openhole reservoir evaluation service. Typically, EBI services are selected during the initial planning of the logging program a few weeks to a few months before the estimated logging date to ensure tool availability. During the initial planning stages, drilling fluid properties and type should be discussed with the service company representative to ensure that the operating environment is compatible with the tool selected and to ensure tool availability.

Case Studies and Key Findings

An operator in West Texas wanted to characterize the occurrence and distribution of natural fractures along the lateral of a well (Kumar and others, 2019). A two-stage approach that consisted of EBI to collect MRES images and dipole SON data resulted in a borehole acoustic reflection survey for processing using 3D far-field SON service (Schlumberger, 2020). The combined effort successfully mapped the location, orientation, and length of natural fractures up to 40 feet around the wellbore. The operator was able to import the fracture data into a reservoir model to improve fracturing and stimulation operations.

Price Estimates

- EBI (low–medium)

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Tools utilizing electromagnetic (EM) technology are based on the physics of pulsed eddy current and provide quantitative metal loss computation from multiple barriers separately (Rourke and others, 2013). Advanced modeling and simulation software can be used to predict job-specific tool responses to allow effective job planning and comparison of simulated model/nominal decays with actual responses from the tool that enables the calculation of wall thicknesses of each barrier independently. The simulated model decays can be used to estimate electrical conductivity, magnetic permeability, and thickness of tubing and casing.

The EM processing principle is based on empirical equations developed using collective data measured at various well completion scenarios. These data are normalized and presented as thickness curves, along with visual representation of the normalized curves in a colored visualization map (Rourke and others, 2014). The normalized data are based on the average nominal thickness of the pipe. For example, color codes such as green represent nominal pipe condition, red represents a metal reduction, and blue refers to an increase in metal (completion items, packers, collars, etc.).

EM tools paired with a multifinger caliper and ultrasonic will provide comprehensive results to detect corrosion intervals and identify the corrosion extent in multiple pipes (Ajgou and others, 2019). It can also be a very cost-effective solution when assessing the mechanical integrity of the well during general maintenance intervals or if a possible breach is suspected.

Applications

- Quantitatively evaluate corrosion damage in single casing strings (Schlumberger, 2009).
- Qualitatively evaluate of multiple casing strings (Schlumberger, 2009, Baker Hughes, 2020).
- Estimate corrosion rate, identify casing corrosion behind tubing, and determine inner radius behind scale (Schlumberger, 2009).
- Determine the percent of metal loss in one to five concentric pipes (Halliburton, 2019).
- Vertical, horizontal, and deviated wells through multiple conveyance systems (Halliburton, 2019; Baker Hughes, 2020).
- Quantitatively evaluate three-pipe thickness and fourth pipe (GOWell, 2021).
- Log memory and slickline in oil, gas, and water wells under operating conditions (Baker Hughes, 2020).
- Individual thickness for up to four tubing/casing layers, damage profile, wall loss, GR depth correlation, pressure profile, temperature profile (Baker Hughes, 2020).

- Monitor corrosion during CO_2 injection without pulling the tubing for evaluation.

- Provide a temperature and pressure profile, and determine depth of sustained casing pressure (Baker Hughes, 2020).

Deployment Logistics

Operating Environment: Cased Hole

Tool Limitations

- EM tools have low spatial resolution and have a lack of response to nonmagnetic scale. EM tools require a relatively high amount of power, which makes the tool difficult to deploy in memory mode.

- EM tools lack localized investigative capability and are best used to investigate corrosion across larger areas of pipe.

- EM tools are only applicable to carbon steel and low-alloy steel; pulsed eddy current integrates over a relatively large footprint. As a result, the smallest defect that can be detected has a diameter of about 50% of the insulation thickness (between 30- and 120-mm insulation thickness) (Crouzen and others, 2006).

Sources of Error

- Electromagnetic properties of tubular can vary with material composition, stress, strain, and aging.

- Erroneous setup information, such as wrong jacket material or thickness, is one of the most common errors observed in the field and can lead to suboptimal results or even false positives (Demers-Carpentier and others, 2021).

Lead Time Required to Deploy Technology

EM is readily available and can be supplied in a relatively short time, depending on the service provider. Typically, EM services are deployed through the tubing and do not require a workover prior to running. During a consultation with the service provider, tubing size, well completion equipment, and all other well components should be discussed to avoid problems with tool deployment and data quality.

Case Studies and Key Findings

A Middle East operator examined a number of wells that displayed records of SAP. The operator needed to assess the casing integrity through the tubing prior to the workover rig move. The main objective was to detect the casing failure in the outer pipes and to inspect if it had reached the internal pipe as well. An EM pipe-thickness detector was able to identify that the source of annulus pressure was due to intensive metal loss in the outer 9-5/8" casing and inner 7" casing metal loss (Ajgou, 2019).

An operator had a well experiencing an Annulus B to Annulus C pressure communication and, therefore, could not be produced. The operator wanted to determine the extent of the corrosion using an EM pipe-examiner tool, which indicated a shallow metal loss anomaly within a few feet of the surface-casing hanger. Additional subsequent surface diagnostics were performed, which indicated the anomaly's shallow location. Since the problem was identified near-surface, a rigless external casing repair could be performed, which will save the cost and avoid the risk associated with using a rig to cut and pull multiple strings of pipe (Halliburton, 2017). In the future, the operator plans to continue using the EM pipe-examiner tool in an effort to survey and prioritize wells for additional proactive corrosion monitoring and prevention.

Price Estimates

- EM (low–medium)

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GAMMA RAY

Natural gamma ray (GR) measurements are one of the most widely used measurements for reservoir characterization and correlation. The GR log measures the natural radioactivity of the formation, measured in American Petroleum Institute (API) units calibrated to the API test facility in Houston, Texas.

GRs are high-energy electromagnetic waves that are emitted spontaneously by some radioactive elements. In a geologic setting, GRs are primarily emitted by radioactive potassium, thorium, or uranium. The GR tool measures the combined contribution of all naturally occurring radioactive elements present in the formation, which, in most sedimentary rocks, reflects the shale content of the formations because of the natural tendency of radioactive elements to concentrate in clay and shale. Clean rocks (rocks with low clay content) tend to have a low level of radioactivity (Schlumberger, 1991, 2021; Asquith and Gibson, 1982).

Applications

- Define bed boundaries, permit correlation of beds between wells, and permit correlation between multiple runs within a well because of the ability to conduct GR measurements in both an openhole and cased-hole environment (Schlumberger, 1991).
- Give a qualitative indication of bed shaleyness, and estimate formation clay content (Schlumberger, 1989, 2004; Asquith and Gibson, 1982; Weatherford 2016a).
- Aid in lithology identification (Schlumberger, 1991; Baker Hughes, 2020).
- Provide cased-hole perforation depth control.
- Provide qualitative evaluation of radioactive mineral deposits (Schlumberger, 1991).
- Measure azimuthal GR (Schlumberger, 2018; Weatherford, 2016b; Baker Hughes, 2021; Halliburton, 2017).
- Correlate well-to-well details in openhole and cased-hole conditions (Weatherford, 2016a).
- Monitor radioactive tracers for injection and stimulations (Schlumberger, 2016; Baker Hughes, 2020).

Deployment Logistics

Operating Environment: Openhole, Cased Hole

Tool Limitations

- GR tools are one of the most robust and widely used reservoir evaluation tools on the market and can be run in nearly any downhole environment. Multiple environmental factors can shift the GR reading; however, the relative values remain constant.

Sources of Error

- Clean formations containing radioactive contaminants, such as volcanic ash, granite wash, or dissolved radioactive salts, will cause a high GR reading, although shale is not present. Some carbonates or feldspar-rich rocks have been found to have a high GR reading (Schlumberger, 1991).

- The density of the formation affects the GR log. Two formations having the same radioactive material per unit volume, but having different densities, will show different radioactivity levels. If all else is equal, a formation with a lower density will appear to be slightly more radioactive (Schlumberger, 1991).

- Increased hole diameter, standoff distance, washouts, or mud weights will decrease the GR reading because of the increased volume of GR-absorbing material between the formation and the detector (Schlumberger, 1991). This effect is typically corrected for during processing.

- Drilling mud containing potassium chloride (KCl) will increase the total GR reading (Weatherford, 2009).

- The presence of casing, the casing thickness, and cement thickness decrease the GR reading.

- Tool size can affect the GR reading (Schlumberger, 1991).

- If run in combination with logging tools containing radioactive sources, multiple repeat passes performed over a short time interval can excite the formation, causing the GR reading to temporarily shift. Therefore, when GR is measured in combination with tools containing radioactive sources, oftentimes the first pass will provide the most accurate data.

Lead Time Required to Deploy Technology

GR logging services are considered standard and/or are required for most openhole logging services and some production or cased-hole evaluation services. GR logs are typically included during the initial planning of the logging program, a few weeks to a few months before the estimated logging date; however, GR is a standard logging service for all well logging service companies and could potentially be ordered on-demand with as little as 6 hours of lead time.

Case Studies and Key Findings

At the Aquistore site in Canada, CO_2 is captured from a coal-fired power generation source and stored deep underground (Shokri and others, 2019). During the site characterization phase, GR measurements provided a final quality check for depth correlation, log-confirmed corrections, and differences between well logs and seismic horizons. The shale volume index used in the EERC model (Peck and others, 2014) was calculated based on data acquired from the GR log. The shale volume index then allowed the lithology of the Black Island to be divided into sand and shale members. An accurate representation of CO_2 injection performance was able to be estimated through GR measurements, along with other downhole tools, computer modeling, and reservoir characterization technologies.

Price Estimates

- GR log (low)
- GR is typically included as part of most basic logging services at no additional cost; however, depending on the logging program, GR may be run as an optional stand-alone service.

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SPECTRAL GAMMA RAY

Unlike the standard total GR logging service, the spectral gamma ray (SGR) logging service measures both the total GR count and the corresponding energy level of each GR in order to determine the individual concentrations of potassium (K), thorium (T), and uranium (U) in a formation (Schlumberger, 1989; Asquith and Gibson, 1982) (Figure 6).

Typically, the T and U concentrations are presented in parts per million (ppm) and the K concentration in weight percent. The average concentration of K in the Earth's crust is approximately 2.6%, U is approximately 3 ppm, and T is about 12 ppm. Specific minerals have characteristic concentrations of K, U, and T; therefore, SGR logs are often used to identify minerals or mineral types. These ratios can be ambiguous, so other data such as photoelectric adsorption coefficients, bulk density, neutron porosity, and SON measurements are used to determine volumetric mineral analysis for complex lithological mixtures (Schlumberger, 1989).

Applications

- Define bed boundaries and increase accuracy of correlation of beds between wells (Schlumberger, 1989).
- Give a qualitative indication of bed shaleyness, and estimate formation clay content (Schlumberger, 1989).
- Increased accuracy as a quantitative shale indicator over the standard GR log (Schlumberger, 1989; Fertl and Rieke, 1980).
- Increased accuracy for calculating the volume of shale in sandstone or carbonate (Schlumberger, 1989; Asquith and Gibson, 1982).
- Aid in lithologic (mineral) identification (Schlumberger, 1989; Fertl and Rieke, 1980).
- Identify and qualitatively evaluate radioactive mineral deposits (Schlumberger, 1989; Fertl and Rieke, 1980).
- Identify mineral and mineral type (Schlumberger, 1989, 2009; Dewan, 1983) (Figure 7).
- Identify clay type and calculate clay volumes (Schlumberger, 1989, 2009; Dewan, 1983) (Figure 7).
- Create volumetric mineral analysis of complex lithological mixtures when used in combination with photoelectric adsorption, bulk density, neutron porosity, and SON logs (Schlumberger, 1989).

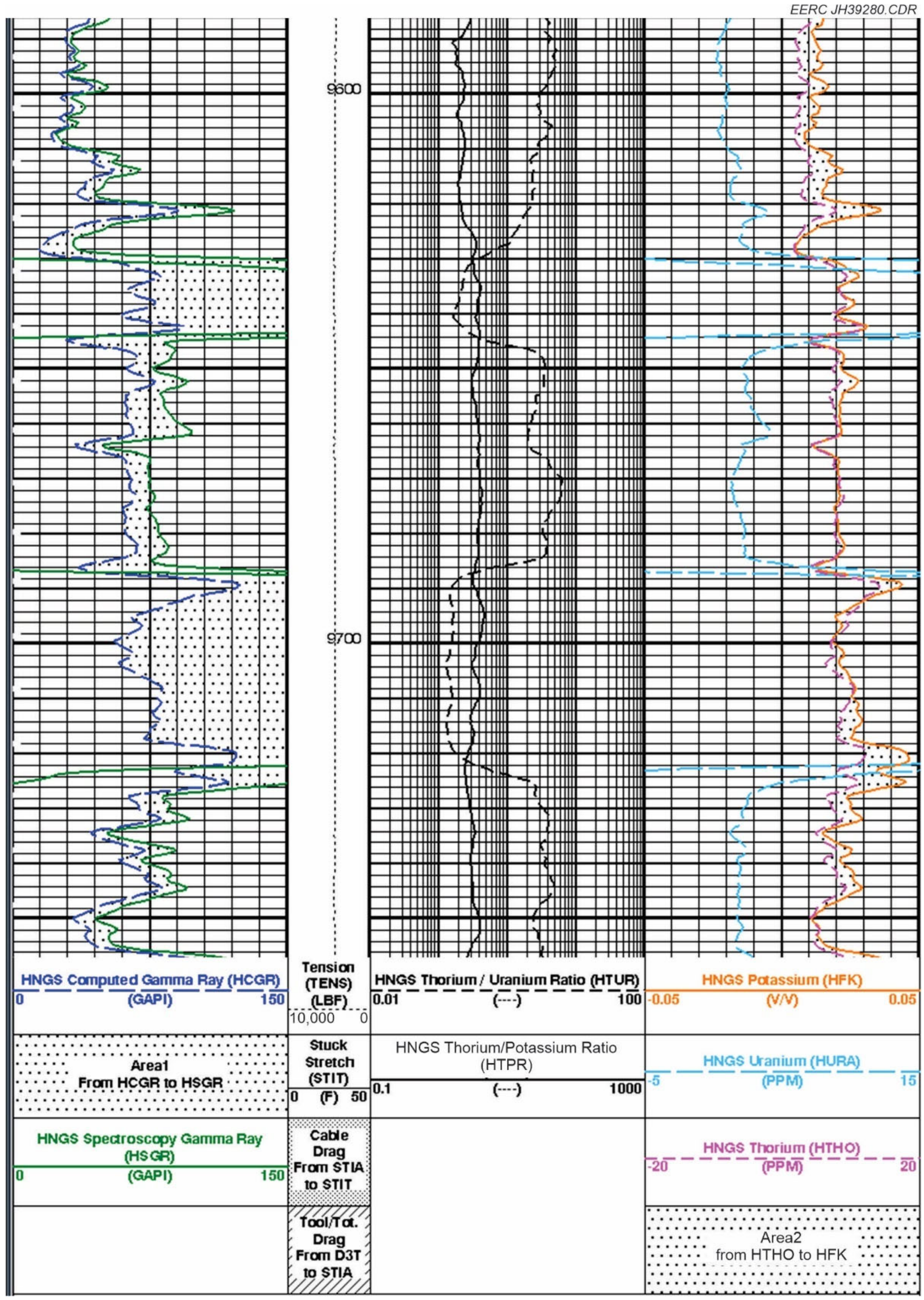

Figure 6. An SGR log example over the Bakken Formation in the Williston Basin. Track 3 (right) shows the percent of potassium (orange) and ppm of U (light blue) and T (pink). Track 1 (left) shows the total GR reading (green), which would be seen with a standard GR log. Track 2 (middle) presents the ratios of T/U and T/K, which are used for mineralogical identification. This log clearly illustrates that the high GR activity in the upper and lower Bakken shales is due to a relatively high concentration of U, which is not present in the surrounding formations.

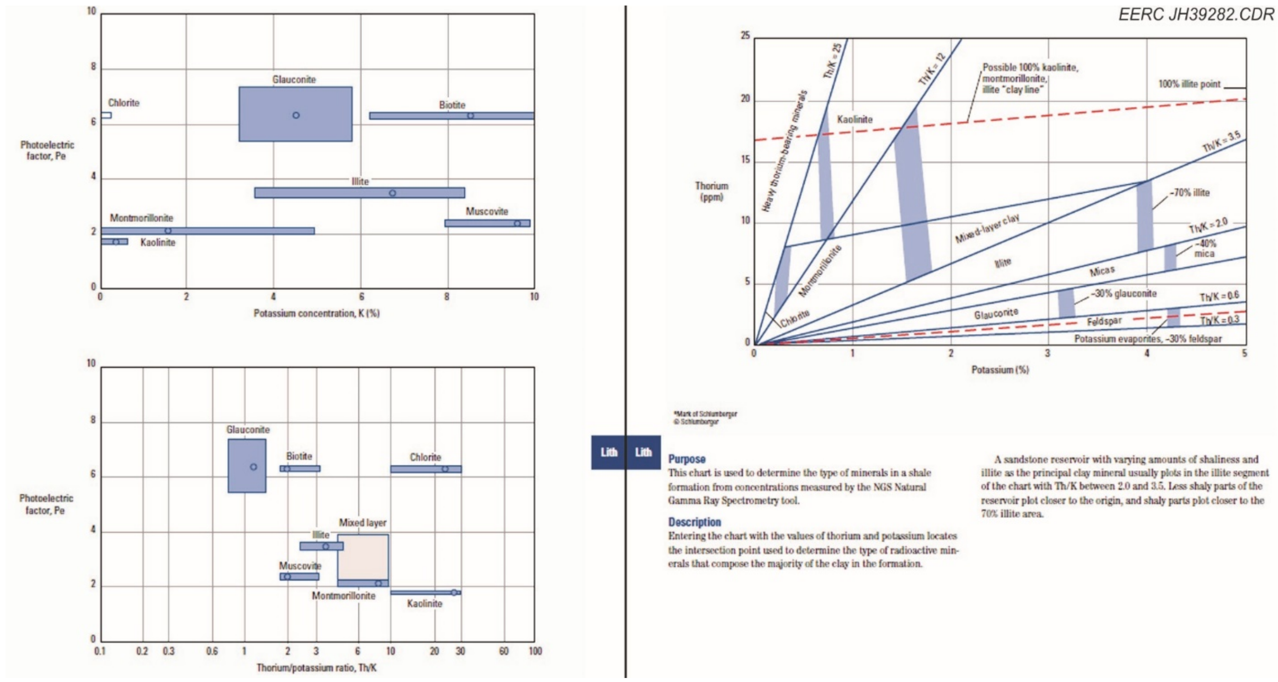

Figure 7. An excerpt from Schlumberger's log interpretation chart book illustrating SGR data usage for clay and mineral typing (Schlumberger, 2009).

- Aid in determination of the source, facies, depositional environment, diagenetic history, and the petrophysical characteristics (surface area, pore structure, etc.) of the rock (Schlumberger, 1989, 2021, 2010).
- Uranium response may be useful as a "moved fluid" indicator for in-field wells drilled into a previously produced reservoir (Schlumberger, 1989).
- Identify zones with permeability or fractures in both open- and cased-hole environments. Permeable streaks may have higher uranium salt content than less permeable intervals; however, this a specialized application and is dependent on the radioactivity of the formation fluids and fractures (Schlumberger, 1989; Dewan, 1983; Fertl and Rieke, 1980).
- Identify, explain, and compensate for sources of error when clay content is estimated through analyzing the spectral contribution of T, K, and U.
- Recognize igneous rock (Schlumberger, 2021, 2010).
- CEC studies (Schlumberger, 2021, 2010).
- Delineate reservoirs (Schlumberger, 2021, 2010).

Deployment Logistics

Operating Environment: Openhole, Cased Hole, Downhole

Tool Limitations

- Spectral GR tools are similar to standard GR tools in that they are robust reservoir evaluation tools and can be run in nearly any downhole environment. Multiple environmental factors can shift the spectral GR reading; however, the relative values remain constant.

Sources of Error

- Clean formations containing radioactive contaminant, such as volcanic ash, granite wash, or dissolved radioactive salts, will cause a high total GR reading, although shale is not present. Some carbonates or feldspar-rich rocks have been found to have a high GR reading (Schlumberger, 1989, 2021, 2010).

- Density of the formation affects the GR log. Two formations having the same radioactive material per unit volume, but having different densities, will show different radioactivity levels. The less dense formation will appear to be slightly more radioactive (Schlumberger, 1989).

- Increased hole diameter and washouts will decrease the GR reading because of the increase of GR-absorbing material between the formation and the detector (Schlumberger, 1989).

- Increased mud weight will decrease the GR reading because of the increase of GR-absorbing material between the formation and the detector (Schlumberger, 2009).

- Drilling mud containing potassium chloride (KCl) will increase the total GR reading and the amount of K detected (Weatherford, 2009).

- The presence of casing, the casing thickness, and cement thickness can shift the GR reading.

- Tool size can affect the GR reading (Schlumberger, 1989).

- Increased hole diameter, standoff distance, washouts, or higher mud weights will decrease the GR reading because of the increased volume of GR-absorbing material between the formation and the detector (Schlumberger, 1989). This effect is typically corrected for during processing.

Lead Time Required to Deploy Technology

Typically, SGR logging services are included during the initial planning of the logging program a few weeks to a few months before the estimated logging date. Because of their specialized use, not all companies may have SGR tools available on-demand; therefore, sufficient lead time may be necessary to ensure tool availability.

Case Studies and Key Findings

SGR logging has seen abundant use in the oil and gas industry for exploration and characterization purposes.

Price Estimates

- SGR log (low)

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IN SITU TESTING AND SAMPLING

In situ testing and sampling (ITS) tools are useful for taking samples or direct physical pressure measurements in the downhole environment. Fluid samples are maintained at reservoir conditions for characterization and geochemical analysis of downhole fluids (Figure 8). Pressure measurements and formation testing are important for a variety of geomechanical and geophysical analysis purposes. A variety of tools are available that vary greatly in their capabilities and applications. Primarily designed for characterization, ITS may also have the potential to be used for monitoring in specialized cases. Particular application to CO_2 storage operations include the ability to quantify fracture gradients, fracture initiation, closure pressures, and formation permeability and to evaluate geochemical fluid properties. New wireline technology (2020) is capable of deep transient testing to evaluate formation deliverability/injectivity and continuity on a larger scale than traditional ITS tools.

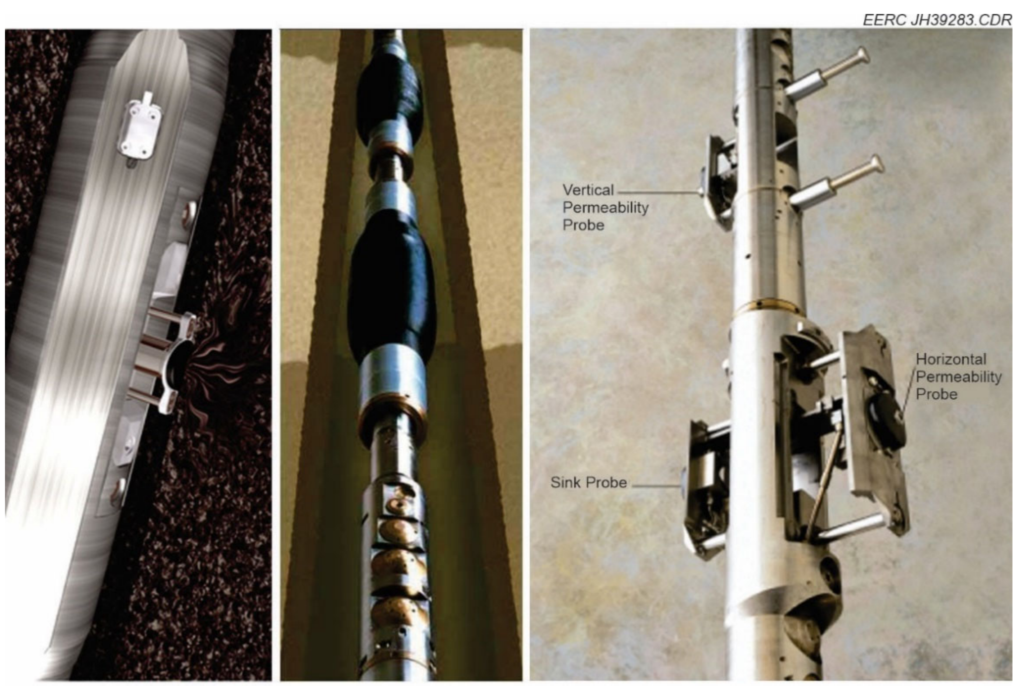

Figure 8. Image depicting a formation pressure tester deployed in a deviated wellbore environment (Baker Hughes, 2010) (left) a combined fluid sampling–pressure testing tool in the deployed position (right) (National Energy Technology Laboratory, 2010), and an MDT dual-packer module designed to isolate a portion of a reservoir for minifracture or drillstem tests (DSTs), mini-DST testing (Schlumberger, 2010) (center).

A recent capability of many sampling tools is the ability to perform downhole fluid analysis (DFA). DFA was originally designed and incorporated into sampling tools to identify when a representative fluid sample, uncontaminated by drilling fluids, was ready to be acquired (Mullins, 2008). DFA could potentially be used in CO_2 operations to provide live fluid chemical analysis under unaltered reservoir conditions to identify in situ CO_2 interactions within the storage reservoir.

Applications

Formation Testing

- Identify formation pressure, pressure gradient, fluid density measurements, and fluid contact (Schlumberger, 2002; Weatherford, 2008a; Baker Hughes, 2008).

- Evaluate formation mobility, permeability, permeability anisotropy, and fluid viscosity (Schlumberger, 2002, 2003, 2007b; Weatherford, 2008a; Baker Hughes, 2008).

- Identify collector zones in gas storage wells (Schlumberger, 2003).

- New technology capable of larger-scale deep transient testing (DTT) (Schlumberger 2020).

- Determine vertical and horizontal mobility (Schlumberger, 2007a).

- Pressure test similar to a direct tension tester (DTT), and minifracture tests to determine vertical/horizontal flow barriers; reservoir connectivity; compartmentalization; stress testing; buildup and leakoff evaluation; and in situ stresses and fracture initiation, treating, reopening, and closure pressures (Baker Hughes, 2008; Mullins, 2008; Weatherford, 2008b; Schlumberger, 2002, 2003, 2007a).

- Pressure monitor during water, steam, and CO_2 injections for openhole and through-casing operations (Schlumberger, 2003, 2007a).

Sampling and DFA

- Collected and maintain fluid samples at in situ reservoir conditions (pressure, volume, temperature [PVT]) until geochemical and PVT laboratory analyses can be conducted (Schlumberger, 2002, 2003, 2007a; Weatherford, 2008b; Baker Hughes, 2008).

- Collect fluid samples for tracer analysis applications in order to track fluid movement within the subsurface.

- DFA (Schlumberger, 2007a,b; Baker Hughes, 2008):
  - Optical spectrometer and optical refractometer (RI) to determine percentage of water, methane, CO_2, and hydrocarbon and water contents in downhole fluids and gas/oil ratio at conditions above bubble point (Schlumberger, 2007b; Baker Hughes, 2008).
  - Real-time compositional analysis of retrograde gases, condensates, volatile oils, and hydrocarbon typing using fluorescence, RES, and optical spectrometers. Optical density peaks correspond to methane, ethane, pentane, heavier hydrocarbon molecules, carbon dioxide, and water to quantitatively measure downhole concentrations (Schlumberger,

2007b; Baker Hughes, 2008; PETROLOG, 2001). Nitrogen can also be indirectly detected in many circumstances (Schlumberger, 2008).
  – Validation of PVT results from lab analysis through in situ DFA (Baker Hughes, 2008).

- Hydrocarbon typing (Baker Hughes, 2008, Schlumberger 2007b).

- Grade fluid composition within a hydrocarbon column (Schlumberger, 2007a).

- Tests in situ phase separation and estimate fluid or gas compressibility in real-time (Baker Hughes, 2008).

- Fluid density and viscosity (Baker Hughes, 2008; Schlumberger 2007b).

- Analyze pH analysis at reservoir conditions (Schlumberger, 2008).

- 3D radial probe that provides a circumferential seal and improved fluid extraction in difficult conditions (Schlumberger, 2018) (Figure 9).

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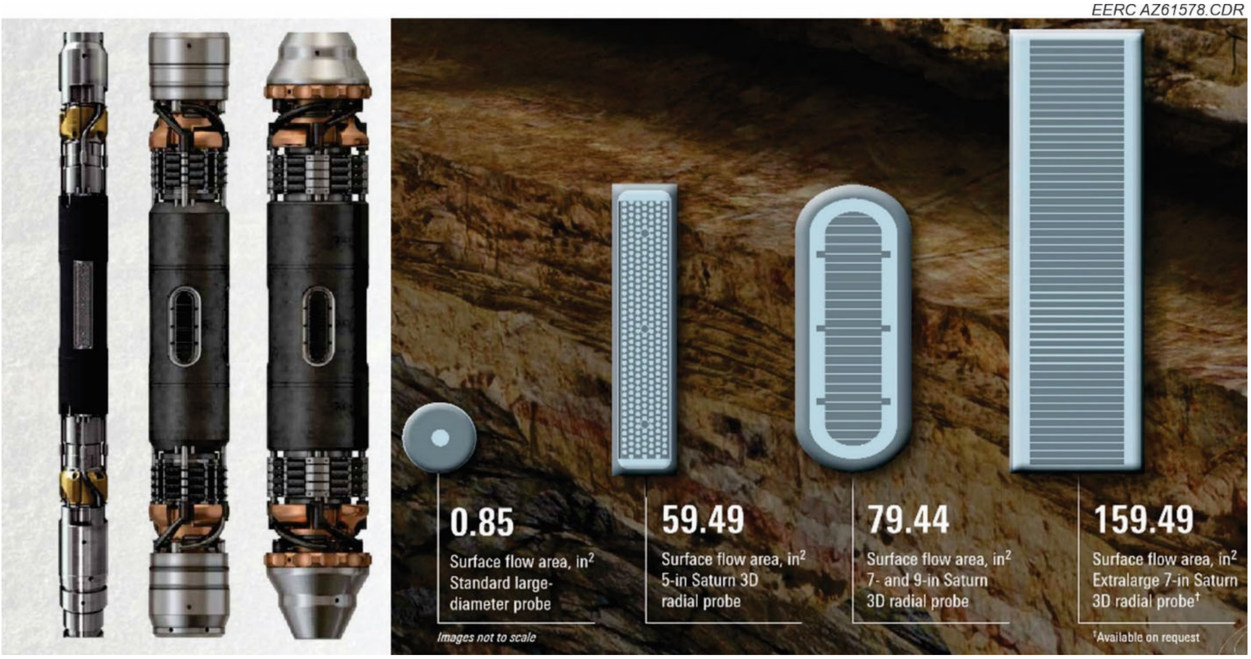

Figure 9. Image depicting the 5- (left), 7- (center), and 9-in. (right) radial probes. The 5-in radial probe features a surface flow area of 59.49 sq in. The 7- and 9-in. radial probes offer larger surface flow areas of 79.44 sq in. and 159.49 sq in. (available on request). The 0.85-sq-in. probe is commonly used for pressure measurements prior to fluid sampling, typically from a shallower location on the tool string (Schlumberger, 2018).

Deployment Logistics

Operating Environment: Openhole, Cased Hole, Downhole

Tool Limitations

- Specialized tools are available with through-casing (analysis behind casing) capabilities. Applicability, limitations, and potential problems should be discussed with a service company representative prior to deployment (Schlumberger, 2003).

- Sample size and samples per run are dependent on tool capabilities and PVT requirements. Typical sample volumes range from tens of cubic centimeters to thousands of cubic centimeters of fluid and can range between 1 and 30 samples per run or more (Schlumberger, 2007b; Baker Hughes, 2008).

- Fluid sampling, pressure testing, and DFA analysis require a minimum amount of permeability within the formation being tested or sampled. Certain tools are suited for low-permeability ranges, while other tools are suited for higher-permeability ranges. The time necessary to obtain a sampling or conduct a test or analysis can range from a few seconds to tens of hours and is, thus, dependent on the permeability and fluid viscosity of the interval being tested/sampled (the higher the permeability and the lower the fluid viscosity, the less time required to obtain a sample, perform a pressure test, or perform DFA). Expected operating conditions and specific applications should be discussed in the planning stages with the service company provider to ensure proper tool selection and availability.

- Differential sticking can occur during testing/sampling operations over permeable intervals with overbalanced conditions (hydrostatic pressure is greater than formation pressure). The probability of differential sticking increases as the overbalance differential pressure increases between the borehole and formation and the longer the sampling/testing tool remains stationary. Differential sticking concerns should be discussed with the service provider prior to operations (PETROLOG, 2001).

- Stress testing and DTT may be limited to certain permeability ranges dependent on individual tool capabilities and pumping capacities. Specific applications and the expected operating environment should be discussed with the service company representative during the initial planning stages.

- Not all tools have combined pressure testing, fluid sampling, and DFA capabilities. Specific applications should be discussed with the service company representative prior to deployment to ensure proper tool selection and availability.

- Many tools can perform a pretest at a specified drawdown rate, drawdown pressure, or drawdown volume, which is a function of formation characteristics, such as consolidation and permeability (Schlumberger, 2007b). Expected formation properties and pressures should be discussed with the service company representative prior to operations to ensure efficient operations.

- Some sampling tools are equipped with water cushions, nitrogen charges, or low-shock sampling chambers to ensure formation fluids do not undergo a pressure drop or phase separations during sampling operations (Schlumberger, 2007b; Baker Hughes, 2008; Weatherford, 2008b).

- Downhole fluid analysis is often available during sampling operations to ensure that fluid samples are representative of downhole conditions (PVT), uncontaminated by drilling fluids, and can be collected and maintained at reservoir conditions (Schlumberger, 2007b).

- Fluid sampling for low H_2S contents evaluation at the laboratory is available.

Sources of Error

- Some sampling tools may not offer DFA capabilities; therefore, it can be difficult to determine if a representative fluid sample is being obtained (PETROLOG, 2001).

- Tight reservoir conditions may make it difficult to identify when formation pressure is reached. The operator may need to define a rate of pressure change (for example 0.1 psi/min) to the service company in order to determine when the test should be concluded. Accurate results in tight reservoir conditions may require certain knowledge of reservoir conditions. Concerns should be discussed with the service provider during planning.

- A pressure drop during sampling operations between the reservoir and sample chamber may allow phase change during sampling operations. Certain technologies are available for selected sampling tools that can prevent a phase change from occurring.

- Heating or other methods may need to be employed during surface analysis after transportation, for example, to revaporize condensed liquids or melt wax precipitates (Schlumberger, 2007b). Specific sampling and required preservation techniques should be discussed with the service company during planning (Schlumberger, 2007b).

- Some tools collect single-phase fluid samples by overpressuring the fluids after they are taken at reservoir conditions in order to compensate for the temperature-induced pressure drop as the samples are returned to the surface (Schlumberger, 2002). Specific concerns should be addressed with the service company provider during the planning stages.

Lead Time Required to Deploy Technology

Testing, sampling, and DFA are not considered standard openhole or cased-hole evaluation services. Testing, sampling, and DFA services require specialized equipment and a specialist on location to conduct operations; therefore, tool and personnel availability are an issue which should be addressed in the planning stages of an evaluation program to ensure equipment and personnel availability. The planning of this type of program should be completed a few weeks to a few months prior to the estimated evaluation date. Additionally, special care should be taken to keep the service company informed of progress to minimize standby time for the rig prior to the start of operations and for the service company. Not all service companies have the capabilities of testing, sampling, and DFA services, and availability should be discussed with specific service providers.

Because of the specific depth intervals over which measurements are required, the evaluation program should be discussed thoroughly with the service company representative during the planning stages and again prior to arrival on location. The evaluation program should include the estimated number and type of samples or tests desired, expected reservoir conditions, and anticipated hole conditions. Oftentimes, it may be necessary to have a qualified on-site geologist or engineer who is familiar with the stratigraphy to pick specific sampling or testing depths of interest from the logs conducted on previous runs. Picking the sampling or testing points from the log data ensures that the proper depth is evaluated and a representative sample or measurement is obtained. This method is oftentimes necessary because of depth shifts between wireline logs, drillers' depths, and mud logs, which can range between a few inches to tens of feet. The depth shifts are caused by tension issues, stretch of drill pipe and wireline, lag time for mud logging, and/or resolution of the depth measurement. A GR log is typically run in conjunction with the sampling or testing operations so correlation between the logs and the coring tool can occur in real time using a GR log.

Case Studies and Key Findings

Schlumberger published a case study from Abu Dhabi of the northern portion of the Arab Formation reservoirs (Schlumberger, 2010). Sampling tools were used to obtain downhole fluid samples for compositional and PVT analysis, including concentrations of hydrocarbon gases, H_2S, and CO_2 (Schlumberger, 2010).

A study was conducted in the Bati Raman Field in Turkey, which contains viscous low-API-gravity oil, focusing on the evaluation of steam and CO_2 injection potentials and their ability to increase recovery factors of 2% after 25 years of production (Babadagli and others, 2008). Fluid sampling was employed as part of an intensive monitoring plan. The CO_2 injection has been reported as successful, although the field was not categorized as a suitable application for CO_2 immiscible flooding (Babadagli and others, 2008).

The EERC at the University of North Dakota conducted a study that required water samples from a reservoir in North Dakota. In the first well, a conventional probe was used, which plugged with unconsolidated formation solids only 30 minutes after pumping commenced. The Saturn 3D radial probe was selected for the second well because of improved fluid extraction in unconsolidated reservoirs that are prone to sanding (Schlumberger, 2020). Six formation water samples with low contamination were successfully captured with unimpeded flow. Many attractive CO_2 storage reservoirs are saline aquifers that can present difficult situations when it comes to collecting a representative water sample. In this case, switching to a probe with a different design and increasing the surface flow area resulted in success.

Price Estimates

- Six fluid samples with DFA (medium–high)
- Ten pressure measurements (low)

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MICRODEFORMATION MONITORING

Nearly every reservoir-level process generates and propagates outward a unique and isotropic pattern of strain that can be detected using sensitive deformation monitoring technologies. Microdeformation monitoring (MDM) seeks to precisely monitor fracture-induced rock deformation to infer hydraulic fracture orientation and geometry. In a similar way, changes in reservoir volumes, such as those produced by fluid production; injection; thermal processes, such as steamflooding, cyclic steam stimulation (CSS), and steam-assisted gravity drainage (SAGD); and CO_2 sequestration also generate unique and measurable patterns of deformation. These patterns, or deformation fields, are measurable at the earth's surface with instrumentation such as tiltmeters, interferometric synthetic aperture radar (InSAR), and global positioning system (GPS). By solving a geophysical inverse problem, precisely measured surface deformation can be used to back-calculate reservoir-level fracturing and volumetric change can be identified and characterized. By bringing the surface deformation measurements down to the reservoir level to obtain the fluid migration pathways, volumetric strain, pressure fronts, or even the thermal fronts, CCS stakeholders may be able to improve their understanding of how different storage and recovery methods work in different types of reservoirs.

Microdeformation Technologies

A variety of independent yet complementary technologies exist at the present time that allow characterization of ground deformation patterns required to geomechanically invert for reservoir-level processes.

Tiltmeters: The tiltmeter has been in operation since the early 1990s and has been used to map over 12,000 hydraulic fracture stages. The tiltmeter is also used worldwide to detect medium- to long-term reservoir change in EOR, CCS, and heavy oil environments. The modern tiltmeter is extremely sensitive, measuring rotation down to the nanoradian level (1 part in a billion). Using surface diagnostics, this extreme resolution has allowed the accurate mapping of fracture orientation and fracture center depth down to depths below 16,000 feet (Wright and others, 1998a,b). Tiltmeters can also be deployed in treatment and offset wells (Wright and others, 1998 a,b) to help illuminate fracture size parameters such as half-length and height. The combination of surface and downhole tilt provides operators with a complete 3D picture of fracture parting and poroelastic swelling processes with the reservoir.

Surface tiltmeters have been continuously deployed for 10+ years in thermal diatomite fields in California, where they are used to detect pressure fronts, out-of-zone steam or fluid movement, and fracture initiation. Surface tiltmeters have been deployed at the Southwest Regional Partnership's San Juan CCS site, the Alberta Research Council's Penn West Pembina site, and the InSalah CCS site in Algeria.

Interferometric Synthetic Aperture Radar (InSAR): InSAR is a technique that can be used to obtain high-spatial-resolution surface deformation maps. InSAR measurements are obtained by active spaceborne microwave sensors (synthetic aperture radar, or SAR) that are capable of operating in all weather and lighting conditions. Earth-orbiting satellites project a beam of microwave energy at the Earth's surface and receive the portion of this beam that reflects from solid features, such as rock or soil, or stable anthropogenic objects (wellheads, streets, corner reflectors). Of crucial importance is the phase of the reflected microwave. If one has sufficient knowledge of the precise position of the satellite in its orbit during each consecutive pass, then the amount a point on the Earth's surface moves over a given period of time may be calculated by measuring the shift in the phase of microwave reflected from that point. Based on this principle, measurements of phase change taken for tens to thousands of points on the Earth's surface are used to produce an interferogram that illustrates movement over very large areas.

Global Navigation Satellite System (GNSS): The GNSS allows for a precise determination of location anywhere on or above the Earth's surface. As of 2011, both the U.S. GPS and the Russian GLONASS are available to commercial entities. Today, most commercial operators primarily use GPS over GLONASS because of its larger more robust satellite network and broader selection of GPS-ready monitoring receivers. Currently 30+ NAVSTAR satellites are operating as part of the GPS constellation, enough to ensure that at least eight are in view at any given time from an unobstructed location. Efficient receivers combined with enhanced differential double- and triple-differencing signal processing techniques allow GPS stations to operate continuously in remote locations, unattended and with accuracies of 1½–2 millimeters or less. GPS is typically employed in reservoir-monitoring environments to effectively augment, correct, and stabilize long-term tiltmeter and InSAR monitoring campaigns.

Applications

- **Hydraulic Fracturing:** Detection of hydraulic fracture parameters from the surface and downhole (Wright and others, 1998a,b; Davis and others, 2000).

- **EOR:** EOR risk mitigation and production optimization (Marsic and others, 2011; Davis and others, 2000; Davis and others, 2001).

- **CO_2 Sequestration:** Detection of CO_2 plume migration using microdeformation and geomechanical inversion routines (Davis and others, 2010; Koperna and others, 2009; Ouidnot and others, 2009; Sweatman and McColpin, 2009).

- **Heavy Oil Recovery:** Heavy oil CSS reservoir monitoring and operational strategy planning; SAGD fluid conformance monitoring (Du and others, 2010).

- **Waste Disposal:** Monitoring of slurry and waste fluid injections into subsurface reservoirs (Griffin and others, 2000).

- **Geotechnical Industry:** Volcano monitoring, tectonic strain accumulation and release, geothermal performance management (Sherrod and others, 2005).

Deployment Logistics

Operating Environment: Openhole, Cased Hole, Downhole

- **Project Design:** Correct deployment of technologies requires due-diligence, including geomechanical deformation estimations, understanding of ground conditions, and client requirements. The aforementioned microdeformation technologies have different strengths and weaknesses, most of which are improved upon through correct project design, including technology integration.

- **Data Point Requirement:** A minimum number of data points (tiltmeters, GPS or InSAR reflection locations) must be deployed or made available for accurate characterization of strain (deformation). Sensor array density and InSAR resolution are tuned for each location and are highly dependent on the CO_2 injection and cap rock depths.

- **Site Requirements:** Power and telemetry considerations must be taken into account for both tiltmeters and GPS deployments. Different countries have different regulations regarding radio transmission and GPS access, which should be considered.

- **Permitting and Access:** Permitting and site access limitations must be accommodated for any field installations (InSAR corner reflectors, GPS monumentation, tiltmeter sites). Shallow 12-m-deep boreholes are required for tiltmeter installations, while shallower monument holes are required for InSAR corner reflectors and GPS monuments.

- **Theft:** Theft of solar panels and communication sources must be evaluated during the site design phase. With advanced knowledge, this can often be mitigated. Most equipment can be installed underground, with the exception of GPS receivers.

- **Analysis:** Analysis and interpretation of microdeformation data require experienced personnel who have a good understanding of the interplay between strain and reservoir processes. The analysis of surface deformation involves use of a geomechanical model that applies strain at a subsurface location. The geomechanical model predicts the surface deformation associated with a given set of subsurface sources and can use either a homogeneous half-space or a layered half-space model. Construction of the geomechanical model and interpretation of the subsurface strain require additional supplementary information. Specific requirements should be discussed with the service provider.

Tool Limitations

- **Tiltmeter:** Drift can impact long-term measurement reliability on the order of months to years. Integration and advanced processing techniques can mitigate this phenomenon.

- **GPS:** 360° line-of-sight at an elevation of >15° above the horizon must be available for the greatest positioning precision.

- **InSAR:** Differential noise can be significant, particularly in leap-frog environments. Advanced processing techniques, which require up to a year's worth of data, are required in order to bring the signal-to-noise ratio to optimal levels, although GPS can be used to jump-start accuracy, then be phased out as an InSAR stack is built up.

- **Radio Networks:** Telemetry for near-real-time monitoring arrays can be dramatically impacted by line-of-sight and RF interference sources. This must be evaluated prior to project deployment.

Sources of Error

The greatest limitation of surface tilt mapping is that some critical details, like individual fracture dimensions, cannot be resolved at fracture depths far greater than the created fracture dimensions. This is because at greater depths not only do the induced surface tilts get smaller but there is also an inherent blurring of the fracture source "edges" as the measurement distance gets larger compared to the separation of the fracture edges (i.e., fracture dimensions). Downhole tiltmeter mapping was developed to get around the fracture dimension resolution limitation by bringing the measurement distance down to the same order of magnitude as the created fracture dimensions. Similarly, for CCS applications, surface tilt meters may not be able to accurately describe small-scale injections, CO_2 injections into small reservoirs, or injections into relatively thin formations at a relatively great depth at a desirable level of resolution without employing downhole tiltmeters.

Interferometric errors can be due to either random or systematic effects. Systematic effects (topographic noise, geometric baseline errors) are mitigated through the use of advanced processing techniques and are, therefore, considered negligible. Random errors (temporal decorrelation, baseline decorrelation) are by definition uncorrelated in time and space and are dealt with using baseline thresholds, temporal filters, and other advanced processing techniques. Since random errors typically vary spatially, true deformation signals will tend to dominate InSAR observations as the SAR data set expands. This increased signal-to-noise ratio, over time, helps with the identification and elimination of random noise responses. For this reason, InSAR products are observed to improve slightly over time as the data set grows.

Lead Time Required to Deploy Technology

Microdeformation is a specialized service that may not be available through all service providers. Microdeformation planning typically requires 6 to 12 months of planning prior to commencement of CCS injection operations. This time frame is often required for not only budgetary reasons but also because of the time required to model expected strain patterns, recommend the correct microdeformation technology approach, and assemble either a tiltmeter/GPS array or InSAR data set (6 to 9 months of background data is desirable). Many field areas have archived SAR data available from which historic reconnaissance evaluations can be conducted if lead times are short or project specifications require.

Case Studies and Key Findings

- Long-term microdeformation monitoring at the Krechba InSalah CO_2 project in Algeria (Davis and others, 2010, Sweatman and others, 2010a, 2010b): reservoir-level inversions reveal unique fluid flow paths for each of the three primary CO_2 injectors, including extreme behavior in one well. Technologies deployed are InSAR, tiltmeters, GPS, and geomechanical inversion.

- Reservoir monitoring in the San Joaquin Valley, California (multiple clients): over 1000 active tiltmeters, 30 differential GPS units, and multiple InSAR campaigns were utilized to provide daily, monthly, and quarterly deformation-based analytical results (Davis and others, 2000, 2001; 2008a,b; 2010). The monitoring program has been active for over 10 years, resulting in a significant number of detected and mitigated shallow events caused by thermal EOR activities. The California Division of Oil, Gas, and Geothermal Resources regulations now often require tiltmeter monitoring for cyclic steaming permitting (Marsic and others, 2011).

- Tiltmeter-based fracture mapping characterizes fracture orientation and depth parameters to 10,000 feet and beyond (Wright and others, 1998a,b). Recent mapping has shown surface-based tiltmeter mapping to be successful at greater than 16,000 feet.

- Integration of InSAR and GPS developed to improve long-term deformation observations and geomechanical inversion capabilities (Davis and others, 2008a,b, Davis and Marsic, 2008).

Price Estimates

- Assume 1-km injection zone, 2-km monitoring region of interest
- Technologies determined based on scope and requirements of project:
  - 55 tiltmeter installations or 55 corner reflectors, including three GPS units (medium–high)
  - Quarterly monitoring + analysis (medium)

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MULTIFINGER CALIPER

Multifinger caliper (MC) tools have a wide array of applications and have been a popular choice for oil and gas operators during all phases of field development. Before drilling, existing wells can be evaluated to assess any potential issues with well integrity that would hinder new development. During drilling, they can confirm borehole geometry, integrity, and volumes for cement providers. Once the completion components have been installed, MC tools can confirm proper placement of the components. Software applications utilizing 3D visualizations of the MC data allows for a deeper look into the drilling and completion diagnostics.

MC measurements utilize configurations from mechanical fingers or caliper arms to accurately measure the internal diameter and geometry of a borehole or casing string on multiple axes for full 360° coverage (Baker Hughes, 2021a). Caliper measurements can be conducted in both openhole and cased-hole environments. Openhole applications include borehole geometry, cement volume calculations, stress analysis, stability evaluations, and environmental corrections of other measurements (Schlumberger, 2010a and b). Cased-hole applications include high-resolution well integrity, corrosion, and wear assessments and identifying wells requiring remediation work (Baker Hughes, 2021a). Applications to CO_2 storage are primarily expected to be related to well integrity studies for risk assessments and for corrosion monitoring (Figure 10).

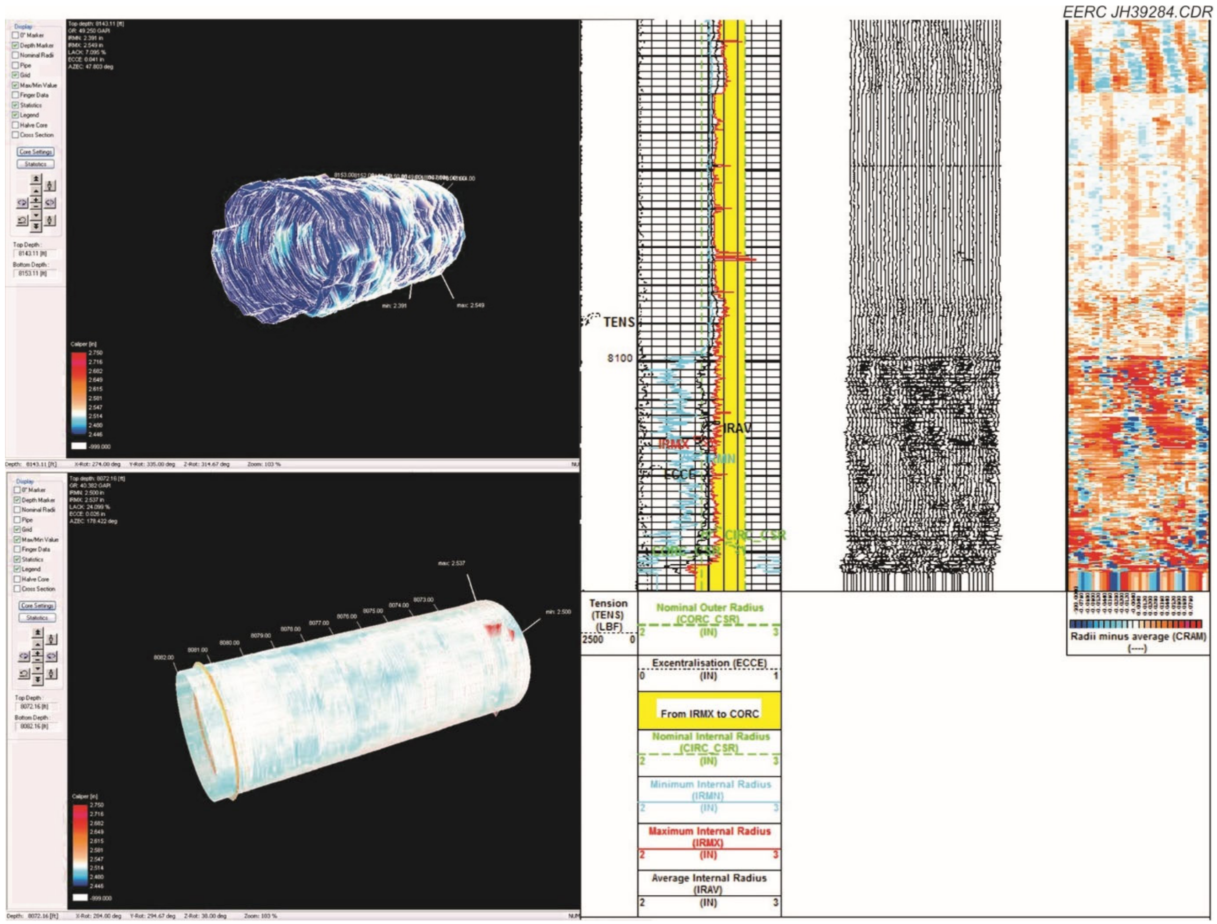

Figure 10. A multipanel image depicting results from an MC log conducted as part of the PCOR Partnership Phase II field validation work at the Northwest McGregor site. Panel A is a 3D visualization of MC data showing a rough surface in the bottom 50 ft of the casing caused by scale or wax buildup. Panel B is a 3D visualization of MC data showing a 2–6-inch hole through the casing at approximately 8072 ft in depth and a casing collar at approximately 8081.5 ft in depth. Panel C is an example of a well log used to create the 3D visualizations in Panels A and B. Track 2 clearly shows the buildup within the casing below 8100 ft and the hole in the casing at approximately 8072 ft. The casing collar at 8081.5 ft is difficult to distinguish in this format because of a rough casing surface; however, a casing collar can be identified at 8050 ft where the casing is in better condition.

Applications

Cased Hole

- Provide borehole geometry data (Halliburton, 2018; Schlumberger, 2008; Weatherford, 2021; Baker Hughes, 2021a; Hunting, 2021).

- Identify and quantifies corrosion damage and pitting (Schlumberger, 2008; Baker Hughes, 2008, 2021a; Weatherford, 2006, 2021; Halliburton, 2018).

- Evaluate and monitors corrosion through periodic measurements (Schlumberger, 2008; Baker Hughes, 2008, 2021a; Weatherford, 2006, 2021; Halliburton, 2018).

- Calculate rate of corrosion and predicting where future issues may occur (Billingham and others, 2012).

- Locate and identify scale, wax, and solids accumulation (Schlumberger, 2008).

- Locate and identify casing wear and mechanical damage (Weatherford, 2006, 2021; Schlumberger, 2008).

- Locate perforations.

- Monitor anticorrosion systems (Schlumberger, 2008; Baker Hughes, 2021a).

Openhole

- Evaluate borehole geometry, including diameter, shape, and estimated hole and cement volumes (Schlumberger, 2010a and b; Baker Hughes, 2021b; LANDSEA, 2021).

- Identify sections of rugose borehole, swelling, and washouts for log quality control.

- Assess borehole stability and evaluates the effectiveness of the mud system (Schlumberger, 2010b; Baker Hughes, 2021b; LANDSEA, 2021).

- Provide environmental corrections for other logs (Schlumberger, 2007; Baker Hughes, 2021b; LANDSEA, 2021).

- Can utilize powered caliper devices to orient other log measurements in either the long or short axis in elliptical boreholes.

Deployment Logistics

Operating Environment: Openhole, Cased Hole, Downhole

Tool Limitations

- Caliper measurements are only capable of measuring the internal surface of the casing. External casing damage, corrosion, or wear is not detectible. While measurements can be utilized to estimate casing collapse and burst pressures, there is an increased uncertainty in the calculation without knowing external diameters or casing thickness.

Sources of Error

- Resolution may be too low to detect pitting, perforations, or minor casing damage and/or corrosion in some circumstances (van Grinsven and others, 2005).

Lead Time Required to Deploy Technology

MC measurements are not considered a standard openhole evaluation logging service. Openhole services should be selected during the initial planning stages of the evaluation program a few weeks to a few months before the estimated logging data to ensure tool availability.

MC measurements are often considered a standard cased-hole well integrity evaluation service. Typically, services are selected during the initial planning stages of the well evaluation program a few weeks to a few months before the estimated well completion date; however, MC services should be available from most cased-hole service companies; therefore, the service could be requested on-demand with as little as 6 hours of lead time.

Case Studies and Key Findings

A study conducted on the Reedijk-1 gas well in the Netherlands, which investigated corrosion management in wellbores with high CO_2 content requiring continuous corrosion inhibition, was conducted by van Grinsven and others (2005). Well corrosion rates were monitored using MC logs. The study found that pitting may be below the resolution limit of certain MC tools. From the conclusion, van Grinsven and others determined that caliper measurements may not be suitable for monitoring corrosion trends in all applications (2005).

A similar study was conducted by Nasr Ramadan and others (2006) in October Field, Gulf of Suez, Egypt. This study presented historical data related to downhole scaling, corrosion, and surveillance methods used to identify affected wells (Ramadan and others, 2006). MC tools were utilized to provide quantitative information on scale buildup and corrosion. Results were confirmed by surface checks after the tubing was pulled during workovers, indicating that the data from MC measurements proved to be accurate (Ramadan and others, 2006). The study concluded that most of the downhole corrosion in the field was caused by CO_2 and high partial pressures in the deeper parts of the well completion.

An operator located in the Middle East conducted a CO_2 flood for EOR. During the flooding process, a 40-arm MC tool was used to evaluate the integrity of injection well equipment (Saada and others, 2018). In the wells that were evaluated, the MC log successfully identified the fracturing sleeve condition as in either an open or closed position. It was also able to detect deformation in the sleeves, which hindered the fracture sleeve from contributing to production. When combining the MC technology with a noise log, the operator was able to confirm the MC results and provide an assessment of the injection profile, detecting channeling behind casing.

A comprehensive well integrity assessment was conducted in three basins (Appalachian, Michigan, and Williston) injecting CO_2 for EOR purposes (Sminchak, 2018). During the Williston Basin study, a well testing apparatus that connects to the wellhead was used to confirm if a well was experiencing sustained casing pressure (SCP). On a select number of wells, an MC log was run before the well testing device was connected to measure pitting and defects associated with corrosion on the inside of the casing. The results could be used to pinpoint where SCP was coming from if it was detected by the external well testing device. A total of 1432 wells were reviewed, 80% of which were tested for SCP. The data sets provided a unique opportunity to study the influence of CO_2 on wellbore integrity.

Price Estimates

- Either open- or cased-hole services (low)

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NUCLEAR MAGNETIC RESONANCE

Nuclear magnetic resonance (NMR) tools have strong permanent magnets that polarize the spin of hydrogen nuclei found in reservoir fluids. To detect the polarized nuclei, the tool generates a sequence of RF pulses to manipulate the polarized hydrogen nuclei and then measure the extremely small RF echoes originating from the resonating hydrogen nuclei. The amplitude of the echo and their subsequent exponential decay rate represent what is known as the T_2 relaxation time, which is primarily a function of pore size but is also related to fluid properties, diffusion effects of the fluid, and paramagnetic minerals (Akkurt and others, 2008). In short, NMR measurements respond to the amount of hydrogen in the formation, with the tool's response a function of the petrophysical properties of the fluid in the formation and the pores that contain the fluid (Asquith and Krygowski, 2004).

Magnetic resonance tools are capable of continuously measuring lithology-independent porosity without the use of radioactive sources. Additionally, they can provide permeability, fluid properties, grain size and fluid movability, and pore-size distribution estimates (Akkurt and others, 2008; Schlumberger, 2007; Asquith and Krygowski, 2004; Martinez and Davis, 2000).

Applications

- Continuously measure lithology-independent porosity and associated permeability (Schlumberger, 2007, 2009, 2019; Asquith and Krygowski, 2004; Weatherford, 2019).
- Measure total and effective porosity and porosity distribution (Martinez and Davis, 2000; Asquith and Krygowski, 2004).
- Shale-effective and clay-bound porosity (Martinez and Davis, 2000; Asquith and Krygowski, 2004).
- Determine free-fluid, capillary-bound, clay-bound, and movable fluids (water and hydrocarbons) (Asquith and Krygowski, 2004; Schlumberger, 2007).
- Determine irreducible water saturations, S_{wirr}.
- Determine in situ fluid viscosity (Mirotchnik and others, 1999; Akkurt and others, 2008; Baker Hughes, 2008b).
- Hydrocarbon type (Asquith and Krygowski, 2004).
- Identify bitumen (Mirotchnik and others, 1999).
- Identify nonproductive hydrocarbons (heavy oil and tar mats) (Baker Hughes, 2008a,b).
- Identify hydrocarbon in low-contrast, low-RES zones (Schlumberger, 2007, 2019).

- Distinguish oil, gas, and water, and identifies fluid contacts (Baker Hughes, 2008a,b, 2021).

- Detect gas.

- Identify thin permeable beds in laminated reservoirs (Schlumberger, 2007, 2019; Weatherford, 2019).

- Evaluate pore-size distribution of reservoir rock quality (Schlumberger, 2007, 2019; Asquith and Krygowski, 2004; Halliburton, 2018a; Weatherford, 2019; Baker Hughes, 2021).

- Quantify hydrocarbon volume in place (Baker Hughes, 2008a,b; Halliburton 2018a,b; Schlumberger 2019, 2020).

- Pseudo-capillary pressure curves (Martinez and Davis, 2000).

- Correlate laboratory core measurements to magnetic resonance imaging logs (Onwumelu and others, 2020).

- Drill through complex lithology (Schlumberger, 2020; Baker Hughes, 2020; Halliburton 2018b).

Deployment Logistics

Operating Environment: Openhole, Downhole

Tool Limitations

- NMR services cannot be conducted in a cased-hole environment or within approximately 50 feet of casing.

- Many NMR tools are not capable of operating in extremely high salinity or salt-saturated borehole fluids. Salinity issues and alternatives should be discussed with the service company performing the work. One possible work-around solution is to pump freshwater over the interval to be logged immediately prior to logging.

- NMR depth of investigating is shallow and ranges from 1 to 4 inches, depending on specific tool type (Schlumberger, 2007). Conventional logs, core data, and capillary pressure data from a core analysis may be necessary to fully evaluate deeper into the formation (Figure 11).

- Accumulation of metal debris on the NMR magnet used to polarize the hydrogen nuclei can distort the magnetic field and affect overall measurement performance. As a preventive measure, ditch magnets should be placed in the flowline to remove metallic debris from the borehole while the well is drilled. These magnets should be cleaned on a daily basis and the debris disposed of. Installation and operation of the ditch magnets are the responsibility of the drilling operator and/or rig (Minh and others, 2005) (Figure 12).

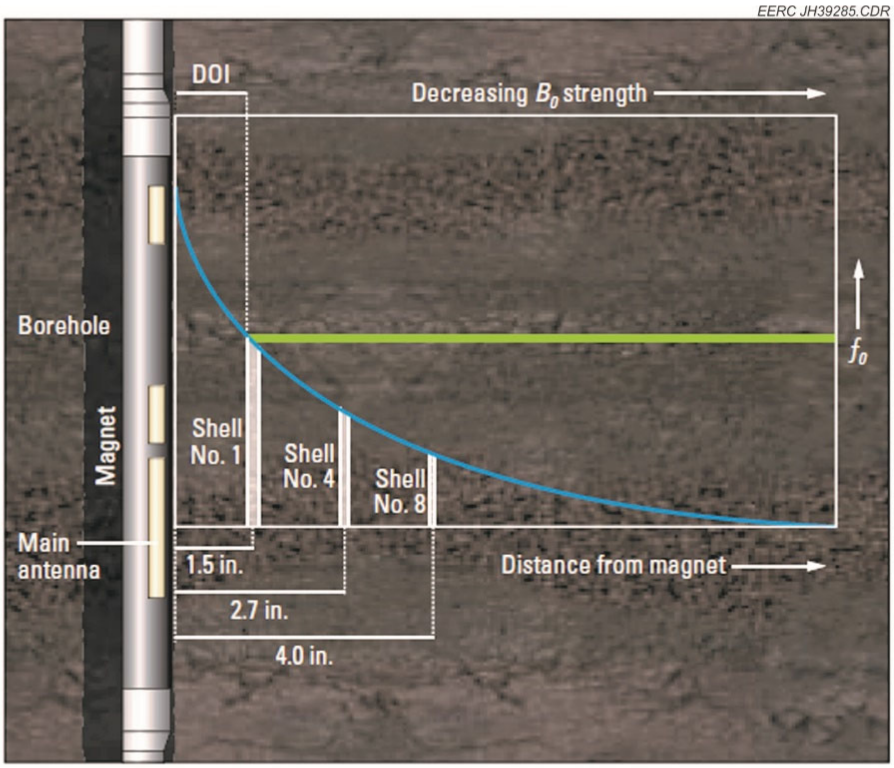

Figure 11. Image illustrating the depth of investigation of an advanced NMR tool capable of recording information at three separate depths of investigation (Akkurt and others, 2008).

Figure 12. Multiple images illustrating magnetic debris buildup on the permanent magnets of an NMR tool after a logging run. Ditch magnets will reduce the amount of debris present in the borehole prior to logging and, therefore, reduce the metallic buildup, potentially improving measurement quality and reducing the time necessary to record measurements (Minh and others, 2005).

- Most wireline conveyed NMR tools have a much slower logging speed than other logging tools (300–1000 ft/hr). Certain specialized NMR measurements may require point measurements rather than a continuous log: bound-fluid mode: 1800 ft/hr (Schlumberger, 2019).

Sources of Error

- Paramagnetic material in the formation can affect T_2 relaxation times, thereby affecting most measurements (Martinez and Davis, 2000).

- Effective permeability is often underestimated in a fractured reservoir (Asquith and Krygowski, 2004).

- Permeability is often overestimated in formations that contain isolated vuggy porosity (Asquith and Krygowski, 2004).

- Permeability and porosity can be underestimated in gas-bearing zones; however, recent processing techniques and modern tools have nearly eliminated this issue (Asquith and Krygowski, 2004).

- Permeability may be underestimated in reservoirs containing heavy oils because of difficulties distinguishing high-viscosity fluids from bound fluids (Asquith and Krygowski, 2004). The development of new and specialized NMR tools is addressing this issue (Akkurt and others, 2008; Baker Hughes, 2008b; Schlumberger, 2007).

- Interpretation of carbonate reservoirs may require calibration to core and conventional logs to provide increased accuracy because of the weaker relationship between pore size and tool response (Asquith and Krygowski, 2004).

- Most NMR analysis requires standard openhole logs, such as RES, density, neutron, and GR data. Some services may require additional core data, core analysis data, and/or formation test data. Specific requirements should be discussed with the service company representative during initial job planning.

- Borehole conditions, such as washouts, may cause the NMR tool to detect borehole fluid rather than fluid-filled formation porosity.

Lead Time Required to Deploy Technology

NMR is not considered a standard openhole reservoir evaluation service. Typically, NMR services are selected during the initial planning of the logging program a few weeks to a few months before the estimated logging date to ensure tool availability. During the initial planning stages, reservoir properties and the desired tool outputs should be discussed thoroughly with the service company representative to ensure that the proper acquisition parameters are used for on-site data acquisition. Not all openhole service companies may have NMR capabilities; however, many of the major companies should offer NMR service.

Case Studies and Key Findings

NMR permeability estimates are comparable with core data (Asquith and Krygowski, 2004). Schlumberger Carbon Services touts NMR as a valuable characterization tool for carbon capture and storage-related projects by allowing more accurate prediction of CO_2 plume growth through better geologic models, allowing characterization and monitoring, verification, and accounting activities to be focused on the correct areas which, in turn, optimize the cost and surface impact of sequestration projects (Schlumberger, 2009).

NMR and ultrasonic measurements were performed on a Bentheimer Sandstone core sample as a function of variable brine and supercritical CO_2 saturation. Utilizing NMR provided a unique approach to study fluid distribution in opaque porous media, i.e., rocks, and can provide unique insight into the physical and chemical environment of the pore fluid (Mitchell and others, 2013). By converting the T_2 times to V/S ratios, these measurements revealed pore fluid effects on elastic-wave propagation as a function of fluid occupation in different sized pores (Connolly and others, 2020). The results from this experiment can be invaluable when it comes to estimating the storage capacity prior to CO_2 injection and monitoring the pore fluid effects as displacement occurs over time.

An operator intended to perform a CO_2 flood in the Grayburg San Andres dolomite formation at Vacuum Field in the Permian Basin. The challenge was determining ROS and oil–water contact (OWC). This was due to unknown water salinity after years of waterflood and variable electrical rock properties. A log-inject-log NMR protocol was employed to address the issues with obtaining ROS and OWC (Toumelin and others, 2011). The NMR techniques coupled with manganese mud doping successfully isolated water from oil signals. Integrating fluid typing capabilities improved mud doping quality control in suboptimal conditions.

Price Estimates

- NMR (low)

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NUCLEAR POROSITY

Nuclear porosity (NP) tools produce porosity estimations based on measurements using a radioactive source to excite the formation and then interpret the radioactive source's effect on the formation. The two primary types of nuclear porosity measurements are density porosity, which also includes bulk density and photoelectric factor, and neutron porosity. Both types of measurements have a different lithology response, which must be accounted for during processing; however, when used in combination, lithology and gas zones can be estimated and a more accurate porosity estimate derived. Typically, neutron and density porosity measurements are run in combination in order to interpret lithology and, therefore, allow for a more robust interpretation (Asquith and Krygowski, 2004; Schlumberger, 2004).

Porosity measurements can be useful for correlating multiple wells. Neutron porosity and formation bulk density are critical formation evaluation measurements for identification and quantification of hydrocarbons, identifying gas zones, assessing reserves, estimating permeability, and assessing geomechanical properties of a formation. Recent advancements have allowed for azimuthal measurements, which deliver density and caliper images, enabling the tool to assess borehole stability, geomechanical properties, and porosity anisotropy (Schlumberger, 2013). Specialized neutron logging tools are available that can provide analysis behind casing (ABC).

Applications and Calibrations

- Determine porosity (Schlumberger, 2004, 2007, 2021; Halliburton, 2007, 2018; Weatherford, 2017; Baker Hughes, 2020).
- Identify lithology (Schlumberger, 2004, 2007; Halliburton, 2020).
- Detect gas and reservoir fluid typing (Schlumberger, 2007, 2021; Weatherford, 2017).
- Identify of mineralogy and photoelectric factor (Schlumberger, 2007).
- Determine hydrocarbon density (Schlumberger, 2007).
- Interpret shaly sand (Schlumberger, 2007).
- Map rock mechanical properties (Schlumberger, 2007).
- Determine overburden pressure (Schlumberger, 2007).
- Generate synthetic seismograms for correlation with seismic (Schlumberger, 2007).
- Include specialized tools allowing for clay-type identification.
- Evaluate ABC formation possibility using many standard NP logging tools (Schlumberger, 2007).

- Estimate permeability.

- Precise nuclear measuring while drilling, lowering the potential for standoff errors, such as those encountered by other logging techniques (Schlumberger, 2021; Weatherford, 2017; Halliburton, 2018; Baker Hughes, 2020).

Deployment Logistics

Operating Environment: Openhole, Cased Hole, Downhole

Tool Limitations

- NP tools cannot distinguish between connected and isolated porosity, such as vugs.

- Alone each porosity measurement is not capable of determining lithology; therefore, both density and neutron porosity are often run in combination with each other and/or in combination with a SON porosity so lithology can be interpreted and, therefore, provide a more accurate porosity estimation (Asquith and Krygowski, 2004).

- Fluid type must be known to estimate bulk density (Asquith and Krygowski, 2004).

- Typically, density measurements are pad-type measurements, which measure a portion of the borehole wall. If significant porosity anisotropy exists or a directional stress orientation is present, which causes either borehole breakout or an elliptical borehole, density porosity measurements will only detect a single orientation. It is possible to run dual density devices offset by 90 degrees, a short- or long-axis-oriented density in the case of borehole breakout, or an elliptical borehole in order to constrain the orientation of the measurement in either the short or long axis.

Sources of Error

- Neutron porosity tools effectively measure the amount of hydrogen in a formation and then convert the amount of hydrogen present into porosity through processing by the assumption that the amount of hydrogen present is representative of the amount of fluid-filled pores (Asquith and Krygowski, 2004). This leaves NP vulnerable to certain types of error:
  - Neutron porosity reads erroneously high in clays (known as the shale effect) because of the high percentage of bound water, as well as in the presence of kerogen because of the hydrogen present in the kerogen molecule.
  - Neutron porosity reads erroneously low in formations containing gas (known as the gas effect or hydrocarbon effect) because of the lower concentration of hydrogen in gas than in oil or water.

- Hole rugosity (roughness), such as washouts, can greatly affect and even invalidate porosity, density, and photoelectric factor (PEF) measurements.

- Actual porosity may be higher or lower than calculated porosity depending on the matrix density and fluid density used for interpretation. Typically, during acquisition, a single matrix and fluid density are used for the entire measured interval. The porosity can be adjusted through additional processing after acquisition is completed (Asquith and Krygowski, 2004).

- Hydrocarbon density, especially for gas, can cause the calculated density porosity to be greater than the actual porosity.

- The neutron porosity response to lithology differs by tool type; therefore, processing and interpretation require the use of the appropriate charts or corrections unique to the specific tool used (Asquith and Krygowski, 2004).

- With heavy muds, especially those containing barite, the PEF of the mudcake can mask the PEF of the adjacent rock layers (Asquith and Krygowski, 2004).

- Because porosity measurements are statistical in nature, logging speed and sticking issues can have an effect on porosity measurements.

- The presence of the radioactive source used in nuclear logging tools can temporarily activate a formation, causing erroneous porosity readings and a shifted GR measurement if the source is exposed for an extended time period to a specific depth interval.

- Neutron logs can be highly affected by clays, hydrated minerals, and gas because hydrogen occurs in them as well as the surrounding pore fluid (Schlumberger, 2010).

- Being a statistical measurement, the precision of neutron porosity logs is greatest at high count rates, which correspond to a low porosity (Schlumberger, 2010).

Lead Time Required to Deploy Technology

Typically, NP measurements are considered a standard openhole reservoir evaluation logging service. They are selected during the initial planning of the logging program a few weeks to a few months before the estimated logging date; however, since NP is a standard logging service for many openhole service companies, it could potentially be ordered on-demand with as little as 6 hours of lead time.

Azimuthal and ABC NP measurements are considered specialized measurements that may require a minimum of 1 month of lead time to ensure tool availability. Not all service companies have these capabilities; therefore, availability and applicability of azimuthal or ABC porosity service should be discussed with the potential service provider during the initial planning stages well in advance of the actual deployment date. Additionally, dual density and axis-oriented density measurements are considered a specialized application and should be discussed with service companies in advance of actual deployment.

Case Studies and Key Findings

A study conducted in Japan focused on CO_2 sequestration monitoring in low-salinity reservoirs. Originally, pulsed neutron-based monitoring was the preferred method to be used at the site. Openhole neutron and density logs were instead chosen because the water salinities present were less than ideal for pulsed neutron-based monitoring (Murray and others, 2010). Neutron-based CO_2 monitoring was found to be well suited for the application because the hydrogen index of carbon dioxide is zero, corresponding to an abnormally low porosity estimation and high carbon/oxygen ratio (Murray and others, 2010).

Another study evaluated the amount of bypassed oil in a CO_2 flood using a combination of several NP tools, including density and neutron porosity tools, to evaluate the remaining oil saturation in a miscible CO_2 flood. Neutron porosity tools were used to compare true porosity and neutron-measured porosity. The neutron tool was found to be the most strongly influenced by hydrogen interactions since CO_2 is effectively displacing hydrogenated fluids (Amadi and Hughes, 2008).

Price Estimates

- Basic NP (density and neutron) (low)
- Azimuthal or ABC NP (low)

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PULSED NEUTRON TOOLS

Pulsed neutron tools (PNTs) utilize a neutron generator rather than a chemical source to emit high-energy particles that interact with reservoir rock. The neutrons penetrate into the rock, even through casing, and are deflected or absorbed by collisions with atomic nuclei (Alberty, 1992). In the event of absorption (known as capture), an atom becomes excited and unstable during absorption of the neutron, causing it to release characteristic GR radiation, which is detected and analyzed by the tool. Sequenced bursts of neutrons are generated by the tool, enabling decay times to be observed and a compensation for borehole fluids to be determined. When different ranges in gamma spectroscopy are examined, many measurements become possible; specifically, the tool is designed to run in two modes: sigma and saturation (Schlumberger, 2007).

Sigma mode examines GRs emitted during thermal neutron absorption. A neutron will undergo thermal absorption once it has undergone a number of collisions, depending on the elemental mass it encounters. After multiple collisions, the neutrons are in a reduced energy state. Hydrogen and other light elements are adept at slowing the neutron to thermal energy levels, while heavier elements may take several hundred collisions to slow the particle. Chlorine is especially efficient in capturing thermal neutrons and is prevalent in saline water but not in oil or fresh water (Schlumberger, 1996). Sigma itself is a measurement of the decay time of the thermal neutrons and correlates to several variables, specifically fluid saturation and water salinity.

Saturation mode examines the GRs that emit high-energy neutrons. The gamma response is geared toward examining only the carbon and oxygen ratio of the returned GRs, which in turn can differentiate saturations of oil, water, and gas (Schlumberger, 2007). This type of measurement is also referred to as induced GR spectroscopy (Julian, 2007).

The latest generation of PNTs are designed to acquire both of the above modes simultaneously, while at the same time adding the elemental spectroscopy measurements common to openhole spectroscopy tools (refer to Capture Spectroscopy above), and further adding a novel measurement that is uniquely sensitive to whether a medium is in a state of high atom density (solid or liquid state) or low atom density (gaseous state). Newer-generation tools may not be available at all service companies and, as such, inquire about specific needs with the provider.

Applications

- Measure sigma (thermal neutron decay time), porosity, and carbon/oxygen ratios (Schlumberger, 2007; Probe 2020).
- Evaluate water saturation in old wells where modern openhole logs have not been run (Schlumberger, 2007).
- Measure water velocity inside casing, including flowing wells, and in the near-wellbore environment outside of the casing (Schlumberger, 2007; Weatherford, 2006).
- Determine formation oil volume from carbon/oxygen ratio (Weatherford, 2006).

- Use elemental spectroscopy-determined total organic carbon (TOC) for formation oil volume (Schlumberger, 2019).

- Analyze hydrogen, chlorine, calcium, silicon, iron, sulfur, gadolinium, and magnesium (in sigma mode) (Schlumberger, 2007).

- Obtain three-phase borehole holdup and phase velocity (Schlumberger, 2007).

- Determine borehole salinity and water saturation in high-salinity formations (Weatherford, 2006).

- Complete lithology (Schlumberger, 2007; Probe 2020).

- Locate bypassed oil zones (Weatherford, 2006).

- Determine formation density porosity and NP through casing and differentiation between low porosity and gas-filled porosity (Weatherford, 2006).

- Detect gravel pack problems (Weatherford, 2006; Probe 2020).

- Identify and evaluate of coal seams.

- Detect the vertical extent of CO_2 near the wellbore.

- Detect out-of-zone CO_2 leakage or migration.

- Monitor near-wellbore saturations of CO_2 (Sorensen and others, 2009; Muller and others, 2007; Vu-Hoang and others, 2009).

- Identify and quantify complex mineralogy and lithology in an openhole environment.

- Differentiate gas-filled porosity from water-filled porosity and very low porosity formations by using fast neutron cross section measurements (Schlumberger, 2019).

Deployment Logistics

Operating Environment: Openhole, Cased Hole, Downhole

Tool Limitations

- Measurements are limited to approximately 10 inches from the wellbore (Schlumberger, 2007) but can measure as great as 18 inches in ideal conditions (Alberty, 1992).

- PNTs in sigma mode can perform poorly in fresh water or where fresh water has been used for a waterflood (Alberty, 1992).

- For sigma-based interpretations of saturation, a correction/calibration for formation fluid salinity is necessary for accurate readings, so at least one fluid identification device should be run in combination with the tool (Offshore, 2001); however, it is unnecessary for the carbon/oxygen ratio-, TOC-, or neutron cross-section-based interpretation of saturation.

- CO_2 time-lapse monitoring requires baseline measurements.

Sources of Error

- Pulsed neutrons are sensitive to reservoir conditions, including trace mineralogy and differences in injected and connate fluids, so results are not readily correlated from one area to another.

- Well and completion design have an impact on the tool, so results may not be precise from well to well.

- The radioactive nature of the measurement may leave nearby minerals in an excited state, which may affect gamma ray measurements for several hours. Repeat passes should be limited because of this excitation (Offshore, 2001).

- Gadolinium, boron, and cadmium have particularly efficient thermal capture properties, which may adversely affect readings (Julian, 2007).

- Porosity measurements taken by the tool produce a large underestimate in the presence of gas (Alberty, 1992).

Lead Time Required to Deploy Technology

PN logging services are typically included during the initial planning of the evaluation program a few weeks to a few months before the estimated logging date. Because of their specialized use, not all companies may have PNTs available immediately on demand; therefore, sufficient time may be necessary to ensure tool availability. Specific applications should be discussed with the service company provider prior to deployment.

Case Studies and Key Findings

Time-lapse PN logs were conducted at the PCOR Partnership's Northwest McGregor Phase II Field validation site in saturation mode to assess unswept oil and to track CO_2 plume movement near the wellbore. The reservoir saturation tool (RST) was convenient in that it could be run through production tubing using pressure control equipment, meaning the well did not lose pressure or vent CO_2 and that the production tubing did not have to be pulled. Three surveys were completed comparing the near-wellbore zone prior to injection, immediately after injection, and 3 months postinjection. Results from the RST log show that CO_2 accumulated in several zones and did not breach the primary seal. This test also validated that RST logs can provide meaningful data in carbonate reservoirs under high-temperature and pressure conditions (Sorensen and others, 2009) (Figure 13).

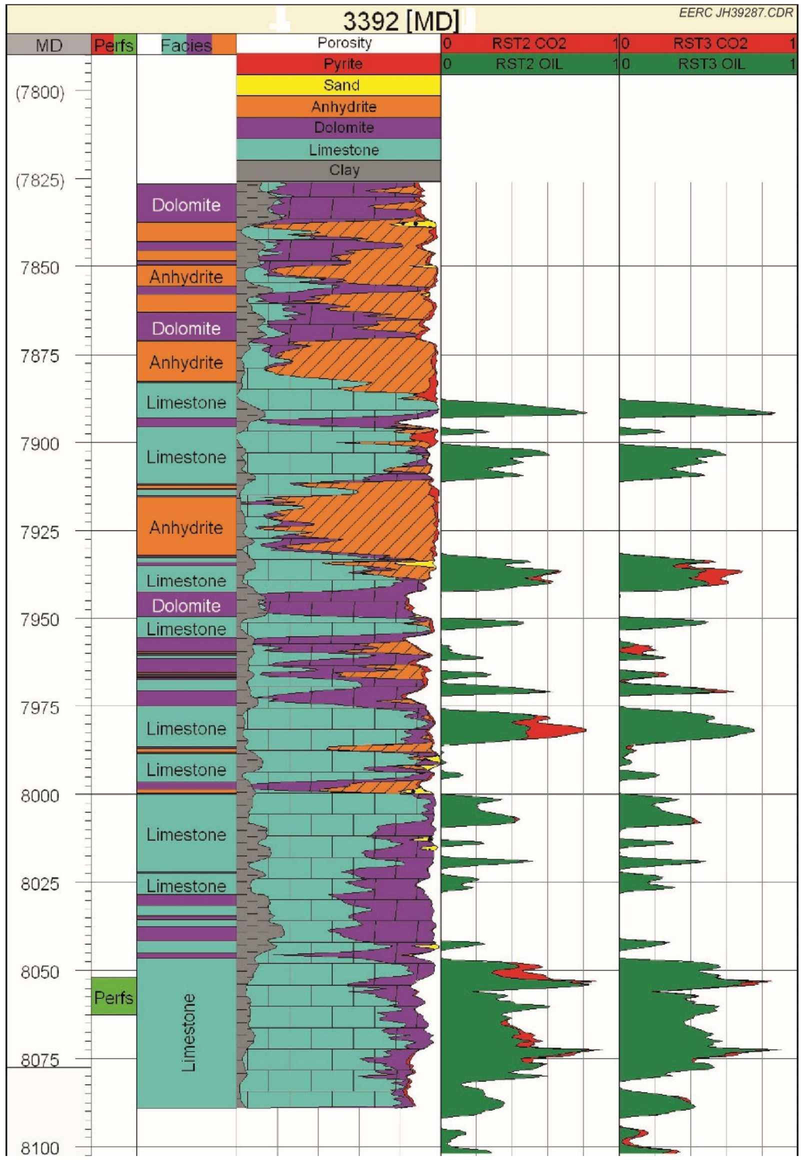

Figure 13. Image depicting the results of time-lapse PN surveys conducted at the PCOR Partnership's Phase II Northwest McGregor Field validation site. The far right tracks show the change in CO_2 and oil saturations immediately after injection (RST 2) and 3 months postinjection (RST3).

A PN log was deployed as part of Southeastern Regional Carbon Sequestration Partnership's Frio Phase II Validation Project to monitor CO_2 migration in a clastic saline aquifer. The log showed CO_2 saturations of up to 65%, and the injected gas appeared to stay concentrated within the porous and permeable zones in the Frio sandstone. In all, the tool was deployed six times to account for baseline and postinjection readings as well as investigation after a well completion change (Muller and others, 2007).

PNTs were used at the CO_2SINK project at Ketzin, where high water salinity and high formation porosity resulted in a high sigma reading between formation water and CO_2, resulting in successful measurements in an observation well following CO_2 breakthrough (Vu-Hoang and others, 2009).

In 2012, the Reservoir Analysis Sonde (RAS) PN system was used during monitoring of a CO_2 flood in the Permian Basin of West Texas (Odom and others, 2013). The PN logging provided real-time analysis of carbon dioxide placement in the reservoir flood with much higher well density coverage. To map the RAS measurements into gas saturation and porosity, the computer code MCNP (Briesmeister, 1993) was used to model the tool response.

Price Estimates

- Pulsed neutron sigma or carbon/oxygen mode (low)

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RESISTIVITY AND MICRORESISTIVITY

Resistivity (RES), also known as specific resistance, is the reciprocal of conductivity and measured in Ω-m (ohm-meters). RES is a geometry-independent material property, which measures the ability of a material to impede the flow of electrical current. Typically, RES is considered a standard service for openhole reservoir evaluation.

The depth of investigation, or the distance from the wellbore that a tool can measure, for a RES measurement can range from less than an inch to over 90 inches. The versatility in the range of depths of investigation makes RES an especially desirable measurement for use in reservoir evaluation. Among other things, RES measurements are used to determine water saturations and lithology and as a qualitative estimate of permeability (Benenson and others, 2002; Schlumberger, 1989; Asquith and Gibson, 1982).

A variety of tool types are available for measuring formation RES in a downhole environment. Specialized tools capable of measuring RES through casing exist; however, as with most ABC tools, data resolution is reduced, and the time required to attain a measurement is increased when compared to openhole measurements. Therefore, ABC is typically used only as a contingency should hole conditions prevent openhole logs or as a method to evaluate completed wells that were not previously logged. A potential alternative use of ABC RES would be reservoir monitoring, and it may be suited for CO_2 plume height tracking and/or leakage detection near the wellbore through utilization of wells penetrating the storage or sealing reservoir in the area of influence of the injection.

The triaxial RES tool is a recent advancement capable of recording both horizontal and vertical RES simultaneously for multiple azimuths, allowing for detection of RES anisotropy and identification and analysis of thin laminated beds using inversion techniques (Schlumberger, 1989; Baker Hughes, 2008) (Figure 14).

RES tools fall into two basic categories defined by the measurement theory used to ultimately produce a RES value. Induction tools use a magnetic field to create a current flow in the formation, which in turn creates a secondary magnetic field that the tool measures and translates to a RES value. Induction tools are commonly used in nonconductive drilling fluids (RES of mud is greater than the true RES of the formation [high R_m/R_t ratio]). Laterolog tools inject a current into the formation and measure the subsequent current return to calculate a RES. Laterolog tools are commonly used in conductive drilling fluids where the R_m/R_t ratio is low. Most modern tools automatically account for geometry to produce a RES value, which is a material property, rather than resistance. While the measurement principle is different between these measurement types, with the operating environment dictating which tool type is best suited for a given application, the final output is RES; however, the measurements may require normalization to be directly comparable (Asquith and Gibson, 1982).

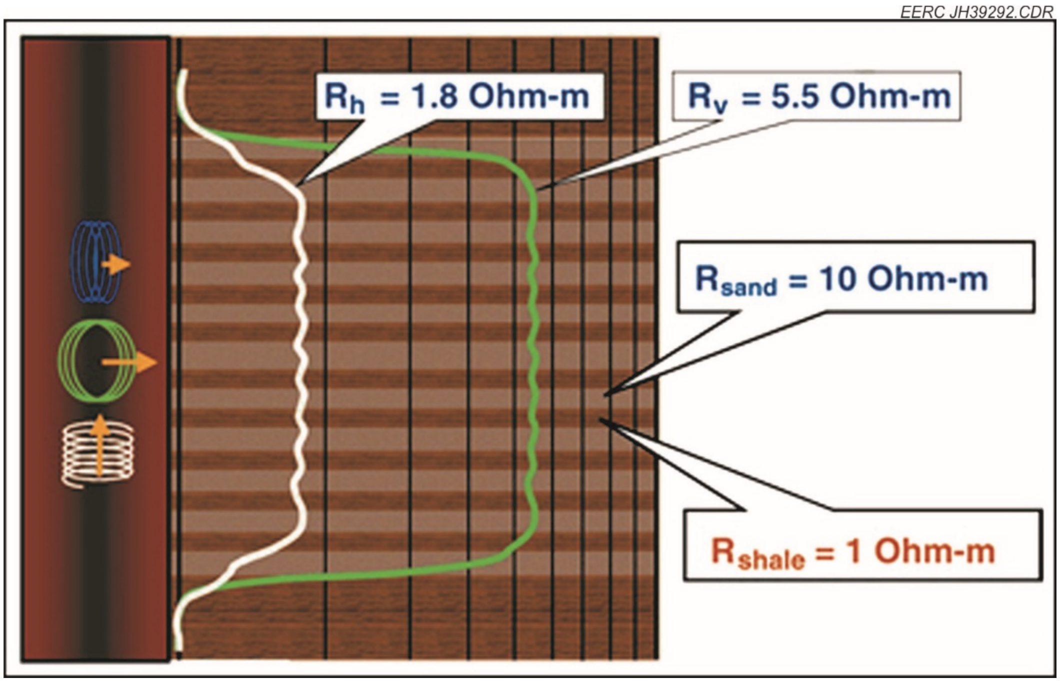

Figure 14. Image depicting the measurement differences between horizontal and vertical RES (Rh and Rv, respectively) in laminated beds utilizing a triaxial RES tool capable of detecting RES anisotropy. Standard RES readings would only provide the horizontal (bed-parallel) RES measurement, which is dominated by the low- RES shale laminae, making the high- RES hydrocarbon-bearing sands difficult, if not impossible, to detect (Baker Hughes, 2008b).

Microresitivity (MRES) measurements are shallow (a few inches or less from the borehole wall) and of higher resolution than typical RES measurements and are used to determine RES of the flushed zone. MRES is useful for estimating movable hydrocarbons, to determine drilling mud invasion, and as a correction for deep RES measurements. MRES is typically included as part of a standard openhole log suite; however, because they often operate on a laterolog principle, measurements may not be valid in certain logging environments, which are better suited to induction-type tools. Other common names include microspherically focused log, microcylindrically focused log, microlog, microlaterolog, minilog, miniresistivity, or focused log.

Applications

- Identify lithology.
- Correlate between wells.
- Determine true formation resistivity R_t (Schlumberger, 1989; Baker Hughes, 2008).
- Determine R_t in laminated formations (requires triaxial measurement) (Schlumberger, 1989; Baker Hughes, 2008).

- Determine horizontal true RES R_h (requires triaxial measurement) (Schlumberger, 2007; Baker Hughes, 2008).

- Determine vertical RES R_v (requires triaxial measurement) (Schlumberger, 2007a; Baker Hughes, 2008) (Figure 12).

- Determine flushed zone RES R_{xo} (requires microresistivity) (Schlumberger, 1989; Baker Hughes, 2008; Asquith and Gibson, 1982).

- Qualitative indicator of permeability through invasion profiling (Schlumberger, 2007a; Baker Hughes, 2008; Asquith and Gibson, 1982).

- Identify gas/oil/water contacts (Schlumberger, 2007a,b; Baker Hughes, 2008).

- Invasion correction of deep resistivity measurements (requires MRES or miniresistivity measurements) (Schlumberger, 2007a,b; Baker Hughes, 2008).

- Thin-bed analysis (Schlumberger, 2007a; Baker Hughes, 2008).

- Delineate reservoir (Schlumberger, 2007a,b).

- Determine RES porosity (requires knowledge of flushed zone RES [R_{xo}], RES of mud filtrate [R_{mf}], and lithology) (Asquith and Gibson, 1982).

- Evaluate of sand–shale laminations (requires high vertical resolution MRES measurements) (Schlumberger, 2007a).

- Formation dip (requires triaxial measurement) (Schlumberger, 2007a; Baker Hughes, 2008).

- Determine water saturation, S_w (Schlumberger, 1989; Baker Hughes, 2008; Weatherford, 2017).

- Determine oil saturation, S_o (Schlumberger, 2007a; Baker Hughes, 2008; Asquith and Gibson, 1982).

- Monitor CO_2 saturation, S_{CO2}, in saline and other aquifers for reservoir (Nakatsuka and others, 2009; Schlumberger, 2007, National Energy Technology Laboratory, 2009; IEA, 2010; Xue and others, 2006).

- Quantitatively estimate of water saturation in the flushed zone (S_{xo}) to provide a qualitative determination of movable hydrocarbons (requires MRES) (Schlumberger, 2007; Baker Hughes, 2008; Asquith and Gibson, 1982).

- Identification fractures (Schlumberger, 2007a,b).

- Detect previously bypassed low-RES oil and gas reservoirs (requires triaxial measurement) (Schlumberger, 2007a,b; Baker Hughes, 2008).

- Analyze shaly sand, and determine shale anisotropy for use in shale interpretation of saturations and irreducible water, including differentiation between thick low- RES beds and laminated thin-bed zones (requires triaxial measurement) (Schlumberger, 2009a,b).

- Detect initial CO_2 breakthrough (IEA, 2010; Xue and others, 2006; Nakatsuka and others, 2010).

- Enhance reservoir understanding by mapping surrounding formation boundaries in three dimensions. In mature fields, improve understanding of fluid movements due to production or water injection. (Halliburton, 2019; Baker Hughes, 2020).

Deployment Logistics

Operating Environment: Openhole, Cased Hole, Downhole

Tool Limitations

- RES similarities and the introduction of a fourth phase may lead to difficulty distinguishing between hydrocarbons and CO_2. Electric logs may require calibration to core, porosity, density, SON and other well logs, fluid samples, or time-lapse techniques.

- RES measurements require an openhole environment or nonconductive casing unless a specialized ABC tool, which has a lower resolution and increased acquisition time, is used.

- Triaxial measurements require inclinometry data acquired simultaneously (Schlumberger, 2009b).

- Temperature-corrected RES of mud R_m and mud filtrate R_{mf} are necessary for water saturation calculations (Schlumberger, 1989).

- Formation water RES R_w must be known for water saturation calculations (Schlumberger, 1989).

- Formation porosity must be known to calculate water, oil, and CO_2 saturations. Porosity can be determined through core analysis and/or other well logs such as neutron, density, or SON porosity. If lithology is not well known, a combination of porosity information may be necessary (Schlumberger, 1989).

- Tool selection (laterolog or induction) is heavily contingent on the R_m/R_t ratio because of the laterolog tool's sensitivity to drilling fluid invasion and measurement theory relying on a conductive medium. Typically, induction tools are suited for high R_m/R_t ratios such as freshwater or oil-based mud systems, whereas laterolog tools are suited for mud systems with low R_m/R_t ratios such as saltwater or brine mud systems. The specific operational ranges of the tool categories overlap in certain circumstances, with some operators electing to run both tool types. Tool selection should be discussed with the service provider prior to deployment (Asquith and Gibson, 1982; Schlumberger, 1989).

- Caliper measurements are often required for borehole corrections.

- MRES and miniresistivity tools often operate on a laterolog measurement principle and, therefore, may not be applicable in nonconductive mud systems (Baker Hughes, 2008b, Asquith and Gibson, 1982).

Sources of Error

- Electrolytes and ion-exchange processes in shales can affect R_t values and saturation calculations and should, therefore, be accounted for during interpretation. Triaxial RES allows for this correction by providing a shale–sand analysis (Schlumberger, 1989).

- Thinly laminated beds can cause erroneous R_t measurements because of the vertical resolution of the measurement causing a smoothing or averaging effect. Certain inversion algorithms can be employed to account for this phenomenon; however, capabilities should be discussed with the service provider prior to deployment (Schlumberger, 2009b).

- Electrically conductive cores, which conduct current when dry, have an effect on R_t measurements and water saturation calculations. If present, they must be accounted for in the interpretation (Schlumberger, 1989).

- MRES measurements are a pad-type tool and are, therefore, greatly affected by borehole rugosity (Asquith and Gibson, 1982).

Lead Time Required to Deploy Technology

Typically, RES and MRES are considered to be a standard openhole reservoir evaluation logging service. They are selected during the initial planning of the logging program a few weeks to a few months before the estimated logging date; however, since RES is a standard logging service for many openhole service companies, it could be ordered in some circumstances on-demand with as little as 6 hours of lead time.

Triaxial and ABC casing RES measurements are considered specialized measurements that may require a minimum of 1 month of lead time to ensure tool availability. Not all service companies have these capabilities; therefore, any triaxial or ABC RES should be discussed with the potential service provider during the initial planning stages well in advance of the actual deployment date.

Case Studies and Key Findings

Various technical papers and studies have been conducted using RES measurements to determine CO_2 saturation and to monitor the initial breakthrough of the CO_2 plume (Nakatsuka and others, 2009) and concluded through laboratory work that it is possible to detect a RES change caused by CO_2 injection and that the RES change could then be used to calculate S_{CO2}, with variable success, using standard and modified saturation equations. A second study, conducted by Xue and others (2006), attempted to demonstrate the applicability of time-lapse RES well logging in order to detect CO_2 breakthrough. Results indicated that time-lapse RES measurements were capable of detecting CO_2 breakthrough; however, the RES log response was smaller than other time-lapse methods used (such as neutron and SON). The smaller log response was attributed to the low CO_2 saturations having a minimal contribution to the overall RES of the formation (Nakatsuka and others, 2010).

An operator in Alberta, Canada, had previous issues with lost tools, had failed to reach total depth (TD), and had been unable to complete nearby wells that ventured into the coal formation. A new approach utilizing a multifrequency resistivity sensor (MFR) while drilling provided the ability to proactively steer downward and avoid contact with the overlying coal formation (Weatherford, 2016). The MFR memory data was continuously analyzed during drilling operations and further tailored the real-time mnemonics for actual well conditions. The well was successfully drilled to a TD of 15,748 ft with no major issues and saved the operator an estimated US$500,000.

Price Estimates

- Basic RES and MRES (low)
- Triaxial or ABC RES (medium)

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DOWNHOLE SEISMIC

Seismic imaging tools and the data they provide are utilized for characterization purposes (such as determining lithological changes and geologic structures, including fractures, faults, or folds in the subsurface) and can be inverted to obtain estimations of reservoir properties (such as porosity, Young's modulus, Poisson's ratio, etc.). Seismic surveys may also be used for monitoring and tracking of fluids in the subsurface through time-lapse surveys (Halliburton, 2007). Seismic surveys utilize a range of acquisition techniques from surface-based (2D, 3D, and 4D [time-lapse] surface seismic surveys or MS surveys) to downhole (such as crosswell surveys or VSPs). This section will cover downhole techniques.

Downhole seismic (DS) surveys typically employ an explosive, vibratory, or piezoelectric source and an array of geophones located on the surface that collect data relating to the travel time and energy of compressional and shear waves (seismic waves) generated by the source (Halliburton, 2007; Schlumberger, 2010). Seismic waves travel the fastest in dense, low-porosity units and slowest in unconsolidated sands or soft clays. Seismic signals split at formational boundaries, resulting in a primary transmitted signal and a reflected signal based on the density shift between the two materials, which can be detected and analyzed as part of the seismic survey. It is important to note that all seismic surveys require processing and interpretation that may take a few minutes to multiple months, depending on the type and extent of the survey. Depending on the processing being conducted, costs may vary (which may or may not be factored into the cost of the survey itself), and additional calibration information may be required for an accurate interpretation. All applications should be thoroughly evaluated in conjunction with the service provider prior to deployment through discussion and/or forward-modeling and resolution analysis, which is utilized to predict the size and type of features that can be resolved in order to ensure proper acquisition and processing for a desired application.

A VSP is a technique in which geophones are placed downhole within a wellbore and receive a signal from a surface source (Weatherford, 2008). Multiple types of VSP surveys exist, which include offset VSPs (Figure 15), walkaway VSPs (Figure 16), and 3D VSPs (Figure 17), and vary based on the desired application and the pattern of the location(s) of the surface seismic source(s). VSPs are especially useful in their ability to provide high-resolution data in close proximity to the wellbore, typically within 2000 ft or less, depending on conditions (Schlumberger, 2007). Time-lapse VSPs have reservoir fluid- and CO_2-monitoring applications because of their ability to detect changes in reservoir properties, such as fluid or pressure changes caused by injection or production activities (Daley and others, 2007). VSPs provide the benefit of a relatively low-cost and smaller surface footprint when compared with surface seismic methods but are limited in areal extent and require a wellbore for data acquisition.

A crosswell seismic survey is a technique in which geophones are deployed downhole within a single wellbore or multiple wellbores, and a seismic source is simultaneously deployed downhole in an auxiliary or adjacent wellbore in order to provide a 2D image of a subsurface

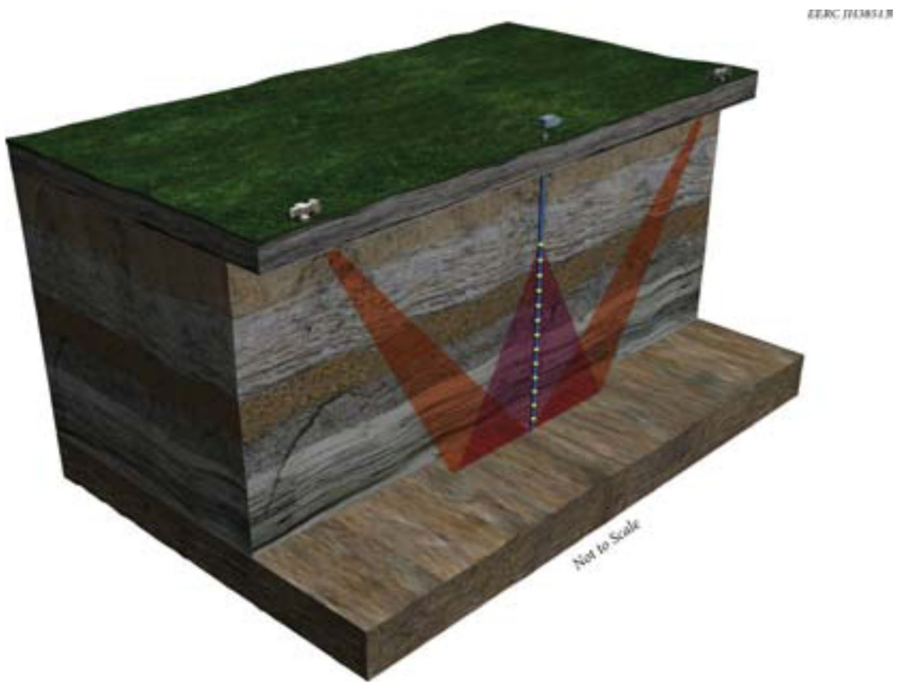

Figure 15. A cutaway image representing a dual-offset VSP survey. An offset VSP survey utilizes an array of sensors in a wellbore to record seismic signals originating from single or multiple seismic source(s) located on the surface, which are offset a distance (typically between 50 and 2000 ft depending on survey requirements) from the wellhead. The surface locations of the seismic sources represent the number of offsets, with between one and four offsets being common. Typically, the first measurement is taken at the deepest point within the wellbore required for the survey, after which, the sensors within the wellbore are incrementally relocated to a shallower depth, with the processes being repeated as many times as necessary. Offset VSPs often require the least amount of time and are the lowest cost of the three types of VSP surveys, but they also provide the lowest-resolution data.

interval between two wellbores (Harris and Langan, 2001) (Figure 18). Crosswell seismic surveys are utilized for reservoir delineation, development, and characterization, with time-lapse methods having fluid- and CO_2-monitoring applications, but they are typically not used for exploration or standard characterization as they require several installed wellbores to be conducted (Harris and Langan, 2001). However, approaches have been used to monitor several different CO_2 injection experiments and pilot programs (Marion, 2014; Wang and others,1998; Daley and others, 2008; Spetzler and others, 2008; Zhang and others, 2012; Ajo-Franklin and others, 2013). Crosswell seismic surveys can often provide higher-resolution data than a VSP (and are considered the highest resolution of all seismic surveys) because of reduced noise and signal losses but also typically have the smallest vertical interval of measurement. Typically, crosswell seismic surveys have a maximum horizontal range between wellbores of <2000–3500 feet.

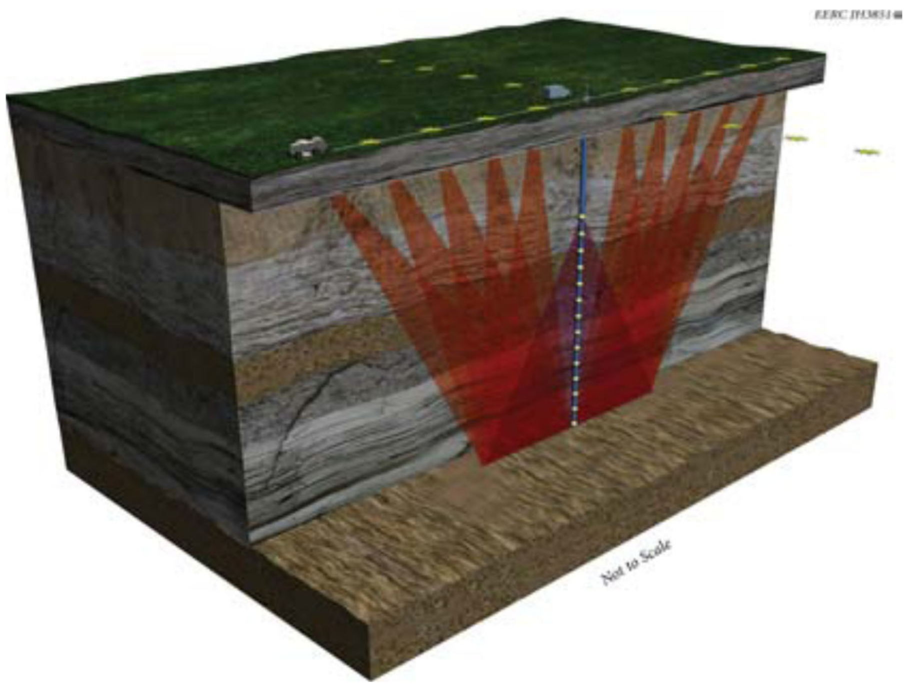

Figure 16. A cutaway image representing a walkaway VSP survey. A walkaway VSP utilizes an array of sensors in a wellbore to record seismic signals originating from a single seismic source located on the surface, which is offset a distance from the wellhead. Typically, a long-string sensor tool is employed that is capable of recording and processing measurements at multiple depths simultaneously (up to 80 or more) so that sensor repositioning between source locations or reshoots of the same source position at a different sensor depth can be minimized. Once the first station is completed, the surface source moves along a line transecting the wellbore, stopping at incremental distances (denoted by yellow stars), with the process being repeated at each location in order to produce one or more seismic cross sections. Walkaway VSP surveys represent higher resolution, cost, and time requirements when compared to offset VSP surveys. Usually, between two and four walkaway lines remain cost-effective when compared to 3D VSP surveys.

Borehole seismic imaging data are versatile and can potentially be combined with other geophysical data as a cost-effective solution for reservoir evaluation or monitoring. DS data can yield improved structural, stratigraphic, and lithological understanding of the reservoir over a larger areal extent than many technologies that evaluate the near-wellbore environment but at a higher resolution, albeit over a smaller area than large-scale surface-based seismic surveys (Weatherford, 2008). Monitoring programs can benefit from seismic and other monitoring technologies because of their ability to image fluid movement away from the wellbore. To date, nearly all commercial- and demonstration-scale CO_2 injection projects have employed some form of time-lapse seismic acquisition in their MVA program for plume imaging and as a means of detecting cap rock leakage (Michael and others, 2010).

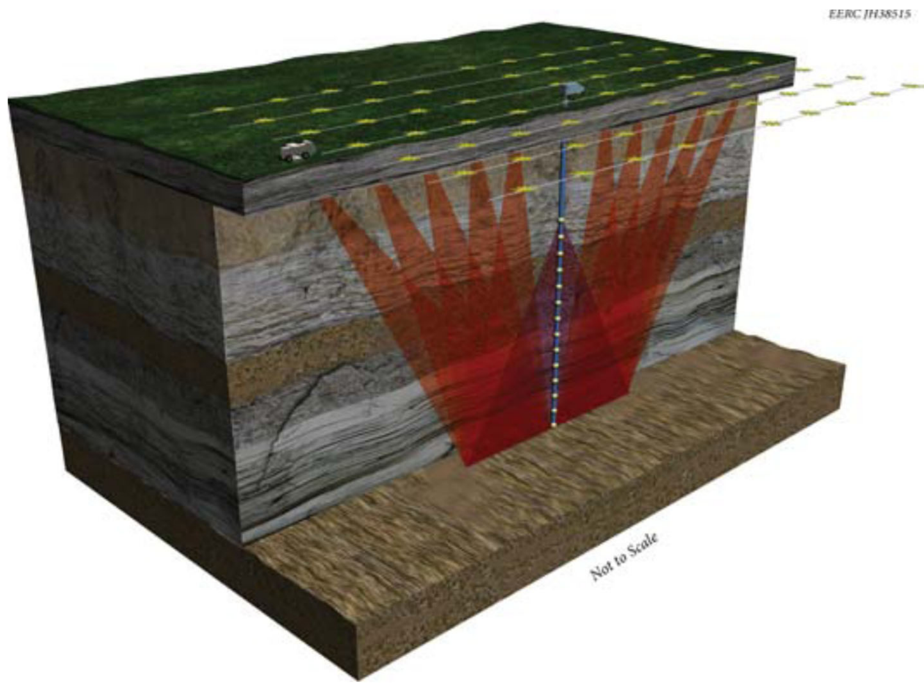

Figure 17. A cutaway image representing a 3D VSP survey. A 3D VSP utilizes an array of sensors in a wellbore to record seismic signals originating from a single seismic source located on the surface, which is offset a distance from the wellhead. Typically, a long-string sensor tool is employed that is capable of recording and processing measurements at multiple depths simultaneously (up to 80 or more), so sensor repositioning between source locations or reshoots of the same source position at a different sensor depth can be minimized (O'Brien and others, 2004). Once the first station is completed, the surface source moves along a grid pattern, typically centered on the wellbore, stopping at incremental distances (denoted by yellow stars). The process is repeated at each location in order to produce a 3D realization of the subsurface. 3D and walkaway VSP surveys represent higher resolution, cost, and time requirements when compared to offset VSP surveys. When compared to walkaway VSP surveys, which require more than three to four walkaway lines, 3D surveys typically become more cost-effective.

Applications

- Provide structural imaging, including features such as faults and pinch-outs (Baker Hughes, 2008).
- Provide structural interpretation, such as dip and formation thickness (Weatherford, 2008).
- Identify location of fault planes, fractures, reefs, pinch-outs, and changes in stratigraphy (Weatherford, 2008; Baker Hughes, 2008).
- Monitor CO_2 plume or reservoir fluid (O'Brien and others, 2004; Halliburton, 2019; Schlumberger, 2014).

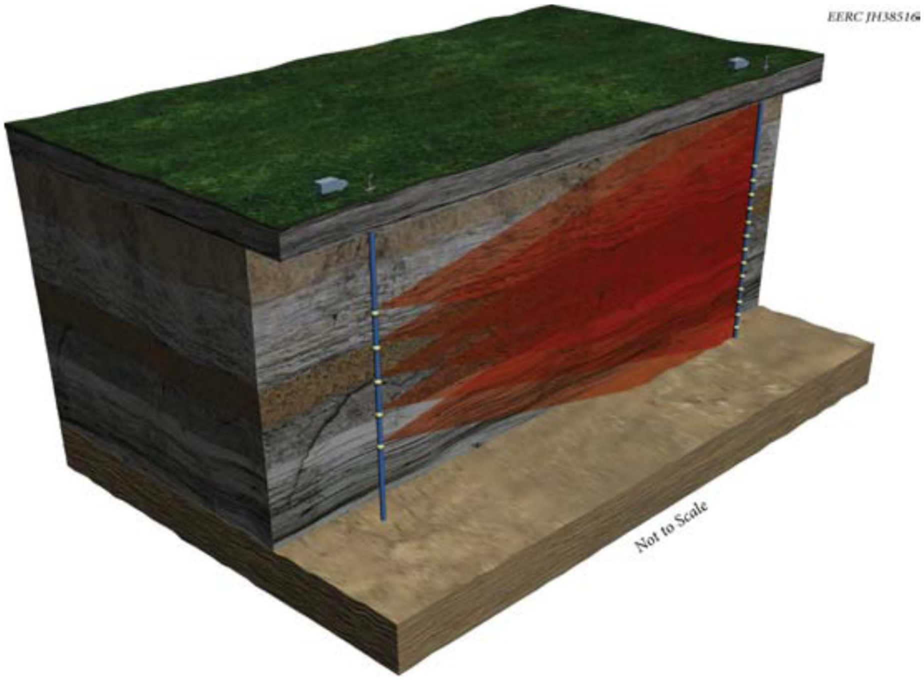

Figure 18. A cutaway image representing a crosswell seismic survey. A crosswell seismic survey utilizes an array of sensors in single or multiple wellbores to record seismic signals originating from an auxiliary wellbore.

- Analyze reservoir properties: seismic signal travel time can be inverted into rock properties such as porosity, density, facies, etc., or used as a covariable in modeling heterogeneous properties such as permeability (Baker Hughes, 2008).
- Provide anisotropy estimates for modeling and simulation purposes (Baker Hughes, 2008).
- Identify overpressure or target zones (Weatherford, 2008; Schlumberger, 2001).
- Monitor pressure away from wellbores, and identify pressurized zones (Staples and others, 2006).
- Estimate Poisson's ratio, Young's modulus, and other elastic rock properties derived from compressional and shear wave inversion (Weatherford, 2008; Baker Hughes, 2008).
- Calibrate the surface seismic data using VSPs, giving an accurate depth measurement to geological features (time–depth correlation) (Weatherford, 2008).
- Quantify reservoir compaction (Staples and others, 2006).
- Monitor CO_2 saturation changes and the distribution, migration, extent, and concentration of injected CO_2 (U.S. Department of Energy National Energy Technology Laboratory, 2009).

- Predict pore pressure (Schlumberger, 2002, 2007).

- Monitor CO_2 propagation through the subsurface, the dynamic response of reservoir rock matrix because of injection, and any out-of-zone leakage caused by unintentional hydraulic fracturing (U.S. Department of Energy National Energy Technology Laboratory, 2009).

- History match and monitor oil and gas production and fluid saturations (Huang and others, 1997, 1999).

- Place the bit on the seismic map while drilling (Schlumberger, 2010; Baker Hughes, 2020).

Deployment Logistics

Operating Environment: Openhole, Cased Hole, Downhole

Tool Limitations

Typically, DS is a much lower resolution than many other well-based characterization technologies yet much higher resolution than surface seismic surveys (Daley and others, 2007). DS data are able to resolve features on the order of tens of feet in size, with crosswell surveys typically providing higher-resolution data when compared to VSP (Daley and others, 2007). Although DS surveys are considered higher resolution than surface seismic surveys, some smaller structural features may still be missed. DS data become cost-effective in their ability to image large areas, hundreds to thousands of feet from the wellbore, whereas most well-based technologies are only capable of acquiring data a few inches to a few feet from the wellbore. Resolution analysis and forward modeling can, and should, be performed during the planning stages of a survey design in order to determine the size of features that can be distinguished with the survey and optimize the survey design for a given application.

- Seismic design benefits greatly from calibration data, such as SON and density logs, vintage seismic, and other geologic and structural information.

- Seismic surveys require federally- or state-issued permits in many areas. Some areas may be inaccessible, such as federal lands.

- Surface accessibility is a concern for survey acquisition. Wet weather, snowfall, rugged terrain, and vegetation may increase the difficulty and/or cost of a seismic survey. Specific concerns should be discussed with the service company provider during planning.

- DS surveys are capable of imaging a maximum of approximately 1000–2000 feet from the wellbore for VSPs and 2000–3500 feet for crosswell. Therefore, they may not be suitable for large-scale CO_2 injection and monitoring projects.

- Walkaway and 3D VSPs may offer more versatility for CO_2-monitoring applications than offset VSPs.

- Time-lapse surveys require maximum repeatability between the original and subsequent surveys in terms of location of the geophones, seismic sources, and subsurface conditions. To ensure repeatability, the original, or baseline, survey must be completed in such a manner as to allow for time-lapse analysis of the subsurface.

- Permanent geophones may be deployed in a dedicated well for time-lapse crosswell or VSP surveys. Cost-effectiveness must be evaluated based on applicability and should be discussed with the service company representative during planning.

- The vertical resolution of the image created between two wells is 5 ft (Schlumberger, 2011).

- During postinjection travel time picking, a large change in waveforms can be interpreted as “guided waves” generated by the newly formed and, CO_2-induced, seismic low-velocity zone (Daley and others, 2008).

- While mapping fluid flow behavior, velocity changes were identifiable to as low as 2% in time-lapse images (Schlumberger, 2011).

- The measured data show that Vp decreases from a minimum 3.0% to as high as 10.9%, while V_S decreases from 3.3% to 9.5% as the reservoir rocks are flooded with CO_2 under in situ conditions. (Wang and others, 1998).

- Depending on the scope of work, fiber-optic cable will give a higher resolution for similar cost compared to crosswell and VSP options.

Sources of Error

- Glacial till; rugged terrain; and poorly consolidated ground surface activities, such as mining, and wet ground conditions, may cause acoustic coupling issues or attenuate seismic signals during VSP surveys. Applicability and concerns should be addressed with the service company provider during planning.

- Heavy equipment, industrial operations, or mining activity may introduce noise into the seismic survey. Specific concerns should be discussed with the service company representative during planning.

- Certain geologic features, such as thick salt beds, can severely attenuate seismic signals, which may or may not be recoverable with additional processing. Specific concerns should be discussed with the service company representative during planning.

- Factors that affect the repeatability of seismic data can greatly affect monitoring capabilities (U.S. Department of Energy National Energy Technology Laboratory, 2009).

Lead Time Required to Deploy Technology

Seismic surveys are generally planned months in advance so forward modeling can be completed, proper equipment, including geophone assemblies, seismic sources (explosives, vibratory trucks, or piezoelectric), and personnel can be mobilized, and proper permits arranged. It is highly recommended to discuss options regarding survey type, limitations, project goals, and cost with the service provider or providers during the planning stages of a project. As seismic data can be crucial for both characterization as well as monitoring, the goals of seismic data collection and interpretation should be determined early in the project and discussed with the service company representative. Sufficient time for data processing should also be factored into the project timeline.

Case Studies and Key Findings

A time-lapse offset VSP was deployed at the Northwest McGregor site during the PCOR Partnership's Phase II field validation tests. The application of the VSP was for both reservoir characterization and MVA activities. Results determined that VSPs may be an effective tool for detecting and monitoring small volumes of CO_2 plumes in deep carbonate reservoirs to ensure safe and permanent storage (Carbon Capture Journal, 2010). Offset or 3D VSPs may provide additional versatility and increased resolution for CO_2 monitoring. Additionally, the VSP survey was able to provide useful characterization data, despite collection depths of over 8000 feet, lithology (including thick salt layers), and other operational conditions (Carbon Capture Journal, 2010) (Figure 19).

The Ketzin project, CO_2SINK, employed a variety of seismic data, including 2D and 3D surface surveys, crosswell, moving source profiling, and VSP. The primary use of the seismic data was for advanced high-resolution characterization of the reservoir (Henoch, 2008); however, three-repeat crosshole surveys for monitoring purposes have been conducted, as well as single-repeat VSP and 3D surveys. This site has also collected data from electrical resistance tomography, reservoir saturation tool logs, distributed thermal, and smart casing technologies (Schmidt-Hattenberger, 2009).

VSPs and/or crosswell seismic for CO_2 projects have also been deployed at Frio (Daley and others, 2005), Aneth, the PCOR lignite site (Figure 20), and SACROC (Cheng, 2010) as part of the U.S. Department of Energy's Regional Carbon Sequestration Partnership Phase II demonstration programs.

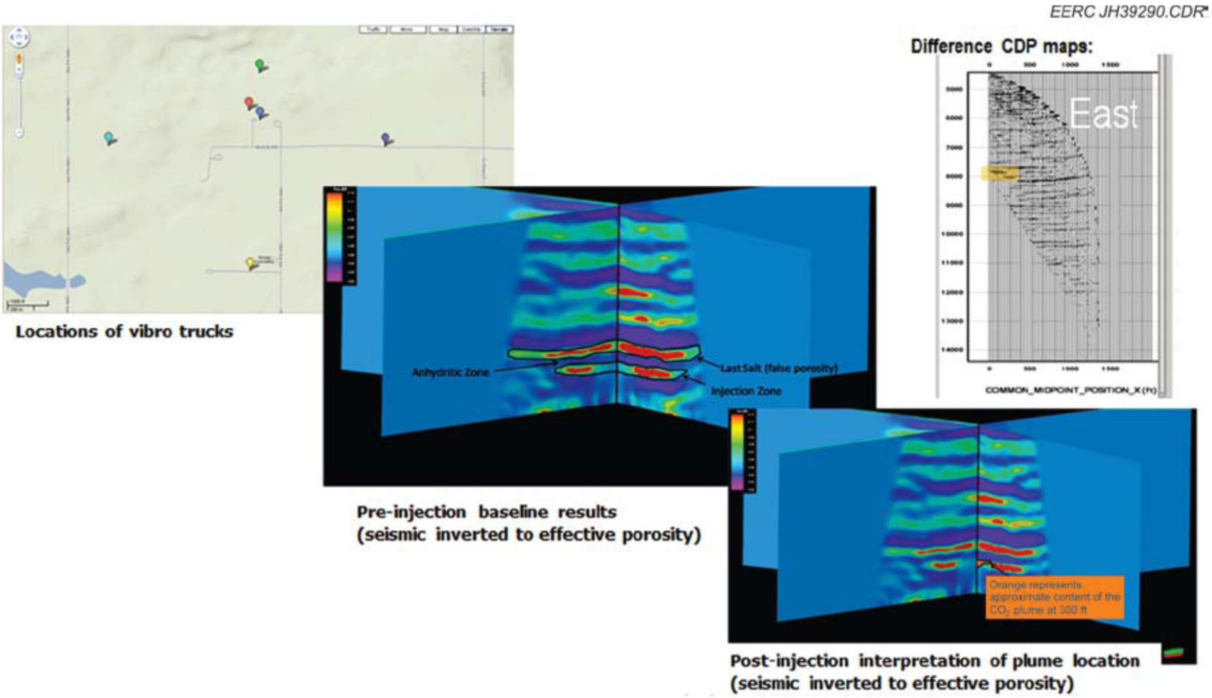

Figure 19. Imaging depicting results of a time-lapse four-offset VSP survey at the PCOR Partnership's Northwest McGregor Field verification site. The east leg of the offset detected CO_2 in the storage reservoir near the wellbore and was in agreement with extensive preinjection simulation results.

During a small-scale CO_2 EOR pilot program in a West Texas carbonate reservoir, time-lapse crosswell seismic profiles were collected between two wells before and after initial injection (Marion, 2014). Several months later, velocity changes indicated the CO_2 had arrived above the perforated interval of the production well. After interpreting the seismic data, vertical fractures were believed to be the cause. Because of the reservoir complexity, engineers were unable to optimize and commercialize the project.

Price Estimates

- Offset VSP (medium–high per offset)
- Walkaway VSP (high per line)
- 3D VSP (high)
- Crosswell survey (high)

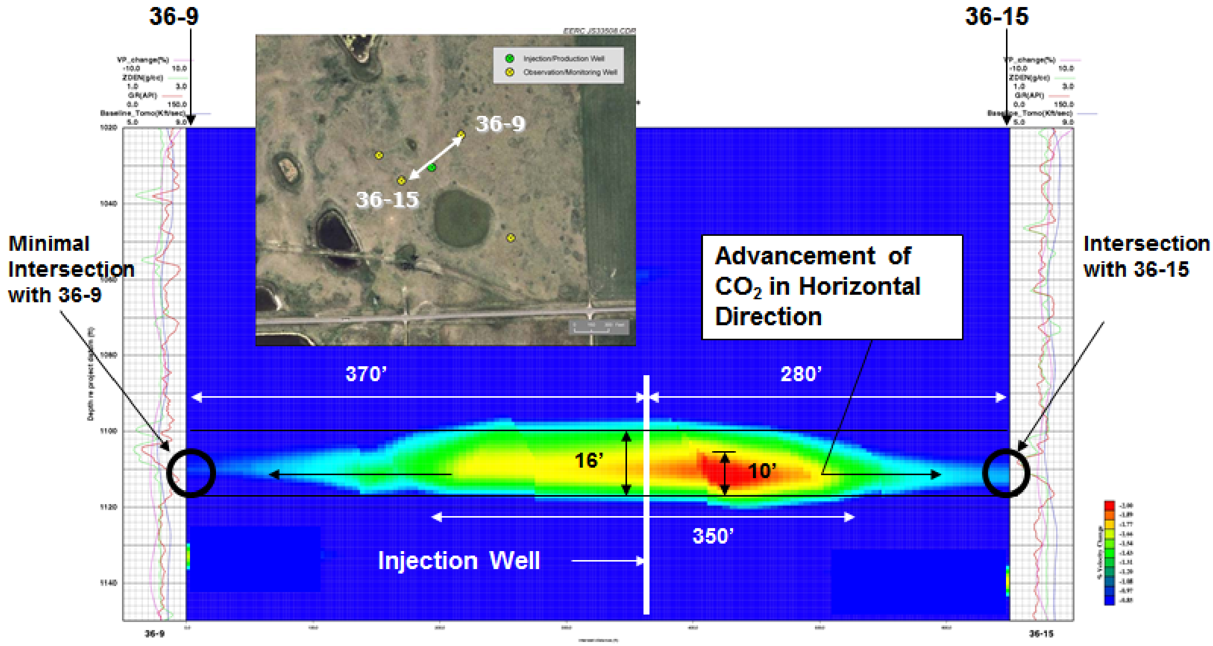

Figure 20. Time-lapse crosswell seismic results from the PCOR Partnership lignite project in north-central North Dakota showing the percentage change in velocity between two wells caused by CO_2 injection, which is believed to correspond with the approximate location and shape of the injected CO_2 plume. Results correlated the well with continuous pressure monitoring in the two monitoring wells used to conduct the crosswell seismic survey.

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MICROSEISMIC

Microseismic (MS) monitoring is a passive monitoring system that differs from more traditional seismic monitoring systems that employ an active (explosive, vibratory, or piezoelectric) seismic source. Instead, MS surveys employ an array of extremely sensitive geophones, either permanently or temporarily deployed on the surface (Figure 21) or within a wellbore (Figure 22), which are capable of detecting extremely small scale (−4 to −1 on the moment magnitude scale, which is approximately 10,000–10,000,000 times smaller than the smallest-felt earthquake caused by displacements of 10–100 µm) seismic events caused by pressure or fluid fronts propagating within a geologic system (Pinnacle, 2011). MS technologies are primarily employed in the oil and gas industry to detect, monitor, map, and orient hydraulic fractures during stimulation of tight oil and gas reservoirs in order to improve production.

MS applications in the CO_2 CCS industry may currently be somewhat limited because of the fact that CO_2 injection programs are designed not to exceed or approach fracture initiation pressures of the storage or sealing reservoirs. However, MS technologies have been included in this report because of potential fringe-monitoring applications as well as CCS's overlap with the oil and gas industry in terms of the EOR applications of CO_2 miscible flooding where understanding reservoir history and characterization work becomes vital for designing the injection and production programs and estimating incremental oil recoveries.

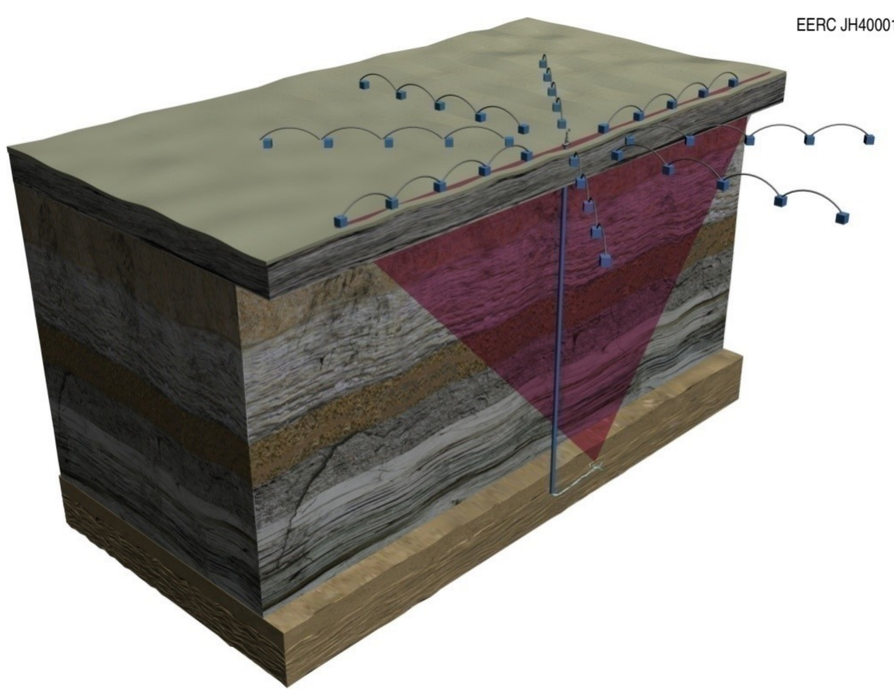

Figure 21. A cutaway image representing a surface-based MS array. MS surveys utilize an array of extremely sensitive sensors or geophones (either buried or temporarily deployed on the surface) to detect seismic waves in the subsurface caused by pressure changes, fluid movement, and/or fracture propagation in the subsurface for monitoring purposes.

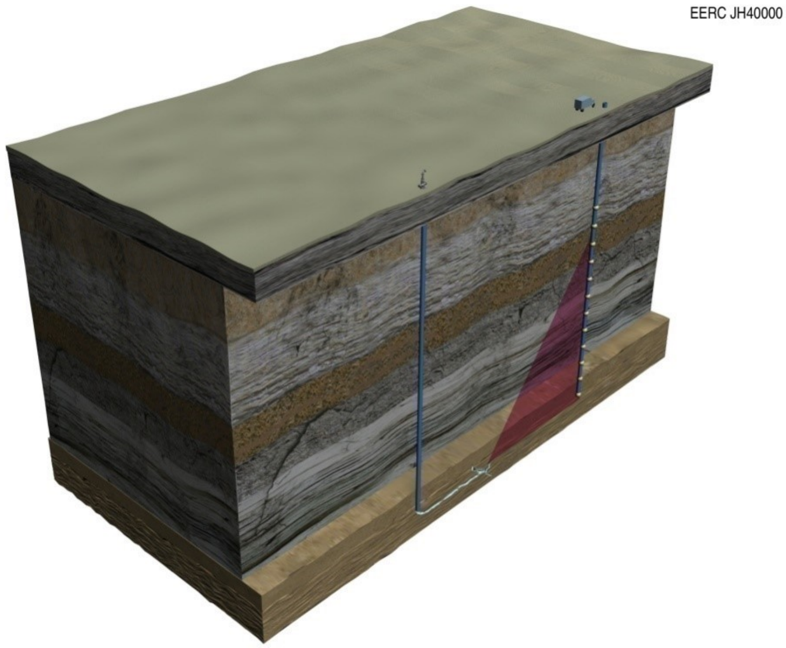

Figure 22. A cutaway image representing a downhole MS survey in which extremely sensitive geophones are deployed within a wellbore to detect seismic waves in the subsurface caused by pressure changes, fluid movement, and/or fracture propagation in the subsurface for monitoring purposes.

While MS techniques do not provide the degree of characterization information that comes from traditional seismic surveys, they may be suited to MVA applications by directly sensing and mapping fractures (or a means of proving a lack thereof) in the reservoir and/or cap rock (Daugherty and Urbancic, 2009) and as a way to monitor for evidence of CO_2 migration through the seal rock or map pressures through a 3D volume (U.S. Department of Energy National Energy Technology Laboratory, 2009).

Applications

- Verify fracture and stimulation program success (Baker Hughes, 2008).

- Monitor seismic during hydraulic fracturing, and map fracture geometries such as location, orientations, azimuths, and lengths (Schlumberger, 2007, 2014; Baker Hughes, 2008, 2021; Halliburton, 2020; Weatherford, 2020).

- Monitor CO_2 propagation through the subsurface; induced seismicity; and dynamic response of reservoir rock matrix because of injection, hydraulic fracturing created by injection, and any out-of-zone leakage caused by unintentional hydraulic fracturing (U.S. Department of Energy National Energy Technology Laboratory, 2009).

- Assess reservoir drainage, drainage efficiency, and interval coverage.

- Monitor fracture complexity and assess the stimulated volume during stimulations of tight oil and gas reservoirs to improve recovery efficiency, well placement, and estimated ultimate recovery.

- Identify geohazards, such as hydraulic fracture interaction with faults, and detect out-of-zone fracture growth.

- Assess the success of refracturing programs.

- Assist with fracture design.

- Provide real-time monitoring data during hydraulic fracturing programs utilized to stimulate tight oil and gas wells in order to actively modify fracture programs.

- Aid in well placement, assess natural fractures, and assess the stress regime.

- Assess lateral coverage and stage isolation during multistage hydraulic fracture programs.

Deployment Logistics

Operating Environment: Openhole, Cased Hole, Downhole, Surface

Tool Limitations

MS monitoring, which analyzes dozens to thousands of very small disturbances within the reservoir itself, is much different than traditional seismic surveys, which analyze a controlled stationary source. While geophones suited for this purpose are highly sensitive, a certain degree of signal-to-noise ratio must be present to avoid erroneous readings. Geophones may be either permanently or temporarily deployed on the surface, within an existing borehole, or a combination of both.

MS may be useful for CCS applications to verify cap rock and reservoir integrity over hundreds of feet to several miles from the injection and provide a reasonably precise location of any specific failure or failures. In the case of EOR and analysis of tight oil and gas reservoir stimulations, hydraulic fracture mapping and estimates of the drainage area for a given well require a precise understanding of the geomechanical properties of the reservoir, surrounding strata, and extensive predictive modeling. MS benefits greatly from calibration data, such as SON and density logs, vintage seismic, and other geologic and structural information.

- Many seismic surveys require federally- or state-issued permits in many areas. Some areas may be inaccessible, such as federal lands. These regulations may be more lenient for MS surveys because of the lack of a physical signal source.

- Surface accessibility is a concern for survey acquisition. Wet weather, snowfall, rugged terrain, and vegetation may increase the difficulty and/or cost of a seismic survey. Specific concerns should be discussed with the service company provider during planning.

- Permanent geophones should be deployed for long-term MS monitoring projects. Cost-effectiveness must be evaluated based on applicability and should be discussed with the service company representative during planning.

- Deep reservoirs may be difficult to monitor utilizing surface-deployed MS sensors.

- Because of the relatively low pressures associated with CCS injections when compared to the oil and gas industry stimulations, MS signatures may not be present or of such a low magnitude that they may be difficult or impossible to detect.

Sources of Error

- Glacial till; rugged terrain; poorly consolidated ground; and surface activities, such as mining and wet ground conditions, may cause acoustic coupling issues or attenuate seismic signals. Applicability and concerns should be addressed with the service company provider during planning.

- Heavy equipment, industrial operations, or mining activity may introduce noise into the seismic survey. Specific concerns should be discussed with the service company representative during planning.

- Certain geologic features, such as thick salt beds, can severely attenuate seismic signals, which may or may not be recoverable with additional processing. Specific concerns should be discussed with the service company representative during planning.

- Many applications of MS monitoring require a precise knowledge of geomechanical data, reservoir properties, and extensive modeling and predictive simulation work, which requires additional calibration data to accurately interpret the data.

Lead Time Required to Deploy Technology

Seismic surveys are generally planned months in advance so forward modeling can be completed; proper equipment, including geophone assemblies and personnel, can be mobilized; and proper permits arranged. It is highly recommended to discuss options regarding survey type, limitations, and cost with the service provider or providers during the planning stages of a project. As MS data can be useful for monitoring and verification, the goals of seismic data collection and interpretation should be determined early in the project and discussed with the service company representative. Sufficient time for data processing should also be factored into the project timeline.

Case Studies and Key Findings

Passive seismic techniques have not been commonly deployed at CCS project sites because their cost-effectiveness is questionable; however, MS monitoring may be a viable option for monitoring under certain scenarios, such as analysis of a CO_2 flood in a previously hydraulically fractured reservoir to assess flood efficiency and drainage.

MS and crosswell seismic methods to map the growth and final geometry of hydraulic fractures generated for oilfield stimulation have been investigated in multiple studies (Bakken Research Consortium, 2008; Warpinski and others, 1999). Imaging of hydraulic fractures at depth has been a long-sought-after goal of the petroleum industry because of the cost of hydraulic fracturing programs. Utilizing multilevel seismic imaging for characterizing fractures may result in increasing hydraulic fracturing project efficiency (Warpinski and others, 1999). Seismic events and hydraulic fracture geometry (height, length, azimuth) have been successfully detected during hydraulic fracturing operations utilizing MS technologies (Warpinski and others, 1999).

While it is certainly not the goal of CCS to produce hydraulic fractures, the technology may be applicable for CO_2 injection projects to monitor plume propagation through the subsurface; induced seismicity; and dynamic response of reservoir rock matrix because of injection, hydraulic fracturing created by injection (or lack thereof), and to detect any out-of-zone leakage caused by unintentional hydraulic fracturing (U.S. Department of Energy National Energy Technology Laboratory, 2009).

The Illinois Basin-Decatur Project (IBDP) CCS site aimed to constrain MS locations with the goal of improving the understanding of the subsurface response to CO_2 injection. The monitoring program consisted of two four-component geophones that were installed in the injection well (CCS1) at depths of 1545 m and 1665 m (PS3-1 and PS3-2, respectively), the monitoring well was located approximately 60 m to the northwest of the injection well and consisted of 31 three-component (3C) geophones with 29 sensors deployed between 418 and 844 m depth, with two near-surface sensors (Dando and others, 2019). The MS observed at IBDP showed distinct event clusters that did not correspond to the geometry of the predicted CO_2 plume. Instead, the event clusters provided valuable information about fluid migration and stress transfer in response to the injection of CO_2.

The Quest CCS project operated by Shell Canada in Alberta, Canada, uses MS monitoring as one part of the measurement, monitoring and verification strategy. MS data is continuously recorded using a downhole array in a deep monitoring well, DMW 8-19. The array consists of eight semipermanent 3C geophones spaced by 50 meters and magnetically coupled to the casing. In 2017, Quest observed an increase in MS activity. The relationship between this increase and the CCS operations is still unclear based on the depth and distance of the events. All recorded MS events are below the Basal Cambrian Sandstone (injection zone) in the Precambrian basement.

Other CCS projects that have utilized MS monitoring to assess containment and induced seismicity risks include Weyburn (Verdon and others, 2010), and In Salah (Stork and others, 2015), among others (White and Foxall. 2016).

Price Estimates

- High

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SURFACE SEISMIC

Seismic imaging tools and the data they provide are utilized for reservoir characterization purposes, such as determining lithologic changes and geologic structural features, including fractures, faults, or folds in the subsurface. In addition to basic reservoir characterization information, seismic data can often be inverted to obtain estimations of reservoir properties (such as porosity, Young's modulus, Poisson's ratio, etc.) or multiple time-lapse surveys can be integrated into a single data set for monitoring and tracking of fluids in the subsurface (Halliburton, 2007). A variety of seismic technologies exist that utilize a range of acquisition techniques from surface-based surveys (2D, 3D, and 4D [time-lapse]) to microseismic surveys to downhole surveys (such as crosswell seismic or VSPs). This section will cover surface-based techniques.

Surface seismic (SS) surveys employ an active seismic source (explosive or vibratory) and geophones, which collect data relating to the travel time and energy of compressional and shear waves (seismic waves) generated by the source (Halliburton, 2007; Schlumberger, 2010). As the name implies, both the seismic source and the geophones are located on the surface. Seismic waves travel the fastest in dense, low-porosity units and slowest in unconsolidated sands or soft clays. Seismic signals split at formational boundaries, resulting in a primary transmitted signal and a reflected signal based on the density shift between the two materials, which can be detected and analyzed as part of the seismic survey. Depending on the processing and interpretation of the seismic data being conducted, costs may vary (which may or may not be factored into the cost of the survey itself), and many times, additional calibration information may be required. All applications should be thoroughly evaluated in conjunction with the service provider prior to deployment through discussion and/or forward modeling and resolution analysis, which is utilized to predict the size and type of features that can be resolved in order to ensure proper acquisition and processing for a desired application.

2D and 3D SS surveys have similar applications but vary based on the arrangement and quantity of the surface sensors. 2D surveys detect seismic waves in a vertical plane by acquiring seismic information along a line of geophones on the Earth's surface (Figure 23). 3D surveys have an added advantage over 2D surveys in their ability to detect seismic waves over a volume by utilizing a grid of geophones on the Earth's surface (Figure 24). 2D or 3D seismic surveys are used to acquire geologic and geophysical information over large areas for characterization purposes, enabling a more robust definition of geology, lithology, and structure (Schlumberger, 2010).

4D seismic is a 3D seismic survey acquired at multiple time steps over the same area and in the same manner in order to assess changes in reservoir properties over time (Schlumberger, 2010). This method allows a 3D survey, primarily conducted for characterization purposes, to be utilized to monitor reservoir gas, oil, and/or water production; CO_2 migration at an injection site; or EOR operations (Chadwick and others, 2009). In addition to monitoring CO_2 plume location, time-lapse seismic surveys may also have potential usage in terms of identifying and monitoring for leakage across no-flow boundaries or vertically through cap rock (if present) (Arts and others, 2008; Huang and others, 1997, 1999).

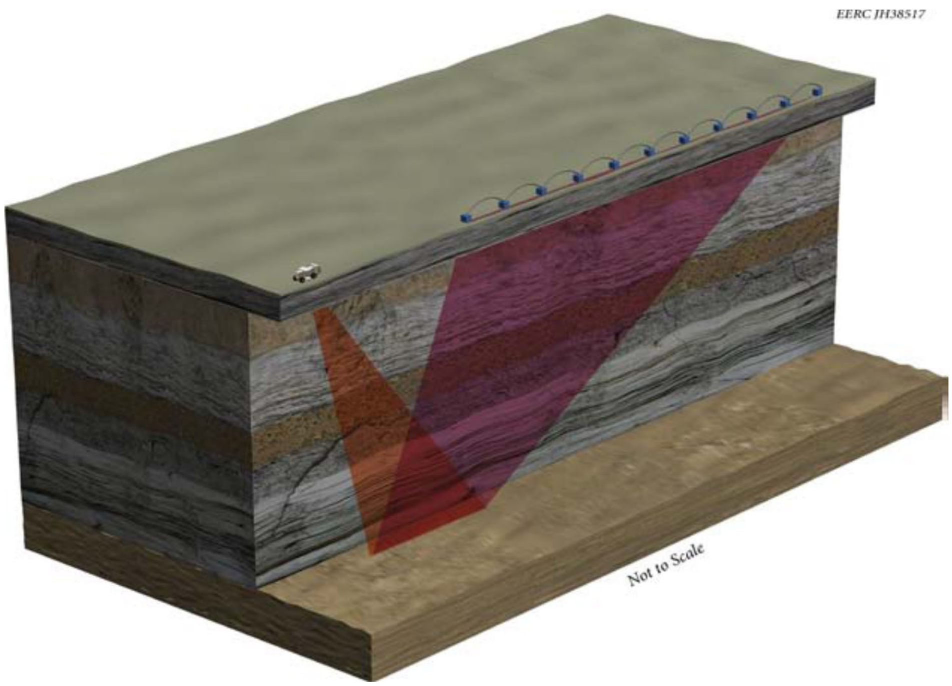

Figure 23. A cutaway image illustrating a 2D SS survey. A 2D surface SS utilizes single or multiple lines of geophones deployed on the surface, which may be many miles long, to record seismic signals generated by a surface source. 2D seismic can only detect features along the vertical plane that directly underlies the sensor line and is oftentimes utilized as a lower-cost alternative to 3D seismic for exploration purposes.

SS imaging is of value because of its ability to provide structural, geophysical, and lithological data over large physical areas that would not be otherwise economical or, at times, even technically feasible with many other downhole geophysical technologies (Weatherford, 2008). While downhole seismic methods such as crosswell seismic surveys or VSPs provide higher-resolution data and are, therefore, capable of resolving smaller features than SS surveys, they are limited in terms of requiring a wellbore and by the maximum distance from a wellbore that can be surveyed effectively, limiting the physical area that can be analyzed to a maximum of a few thousand feet.

SS surveys may be useful for CO_2 CCS projects because of their ability to acquire data over areas that have either no data or poor-quality data (Halliburton, 2007). Additional CCS utility may be realized in terms of monitoring applications, as SS may be one of the only geophysical technologies capable of imaging and tracking the migration of an entire CO_2 plume during a large-scale injection. This would provide accurate history-matching data to update the modeling and simulations. Nearly all CO_2 injection projects to date have employed some form of time-lapse seismic acquisition as part of their monitoring program in order to track CO_2 migration within the subsurface or as a means of ensuring containment of CO_2 within the storage reservoir (Michael and others, 2010).

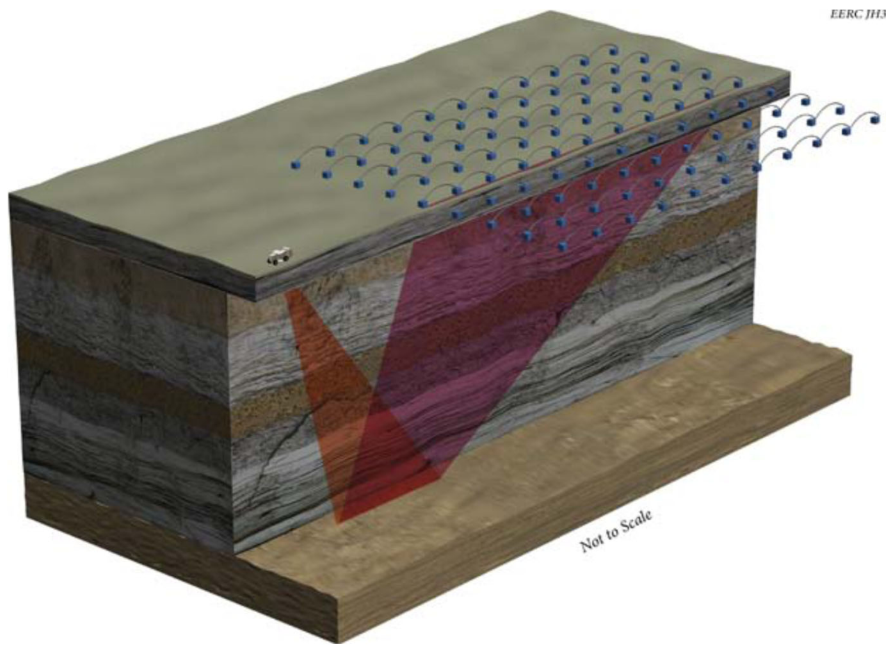

Figure 24. A cutaway image illustrating a 3D SS survey. A 3D SS survey utilizes an array or grid of sensors or geophones deployed on the surface, which can cover multiple square miles, to record seismic signals generated by single or multiple surface seismic sources. 3D seismic can detect features that underlie the grid, thereby allowing volumetric interpretations of the subsurface. 3D seismic surveys are especially useful for supplementing detailed characterization work over an area multiple square miles in size or when the geologic structure can vary within the study area. 4D SS, which is primarily used for monitoring applications, is essentially a time-lapse 3D SS survey that has been given special consideration to ensure repeatability.

Applications

- Structural imaging, including features such as faults and pinch-outs (Baker Hughes, 2008).
- Structural interpretation, such as dip and formation thickness (Weatherford, 2008).
- Locate fault planes, fractures, reefs, pinch-outs, and changes in stratigraphy (Weatherford, 2008; Baker Hughes, 2008).
- Time-lapse surveys to track and monitor CO_2 plume location and migration.
- Monitor reservoir fluid during production or EOR operations.
- Analyze reservoir properties. Seismic signal travel time can be inverted into rock properties, such as porosity, density, facies, etc., or used as a covariable in modeling heterogeneous properties such as permeability (Baker Hughes, 2008).

- Provide anisotropy estimates for modeling and simulation purposes (Baker Hughes, 2008).

- Identify overpressure or target zones (Weatherford, 2008; Schlumberger, 2001)

- Pressure monitor away from wellbores, and identify pressurized zones (Staples and others, 2006).

- Estimate Poisson's ratio, Young's modulus, and other elastic rock properties derived from compressional and shear wave inversion (Weatherford, 2008; Baker Hughes, 2008).

- Quantify reservoir compaction (Staples and others, 2006).

- Survey salt proximity (Schlumberger, 2001).

- Monitor CO_2 saturation changes and the distribution, migration, extent, and concentration of injected CO_2 (U.S. Department of Energy National Energy Technology Laboratory, 2009).

- Monitor CO_2 propagation through the subsurface, dynamic response of reservoir rock matrix because of injection, and any out-of-zone leakage caused by unintentional hydraulic fracturing or seal integrity issues (U.S. Department of Energy National Energy Technology Laboratory, 2009).

- Predict pore pressure (Schlumberger, 2002, 2007).

- History match and monitor oil and gas production and fluid saturations (Huang and others, 1997, 1999).

Deployment Logistics

Operating Environment: Surface

Tool Limitations

Typically, SS resolution is much lower than many other characterization technologies, including DS methods (Daley and others, 2007). SS surveys are able to resolve features on the order of tens to hundreds of feet in size depending on survey design and type; therefore, some smaller structural features may be missed. However, seismic surveys are cost-effective in their ability to image large areas from thousands of feet to hundreds of miles for 2D surveys (thousands of square feet to hundreds of square miles for 3D surveys), whereas most other geophysical technologies are only capable of acquiring data a few inches to hundreds of feet from the wellbore. Resolution analysis and forward modeling can and should be performed during the planning stages of a survey design in order to determine the size of features that can be distinguished with the survey and optimize the survey design for a given application.

- Seismic design benefits greatly from calibration data, such as SON and density logs, vintage seismic, and other geologic and structural information.

- Seismic surveys require federally- or state-issued permits in many areas. Some areas may be inaccessible, such as federal lands.

- Surface accessibility is a concern for survey acquisition. Wet weather, snowfall, rugged terrain, and vegetation may increase the difficulty and/or cost of a seismic survey. Specific concerns should be discussed with the service company provider during planning.

- 2D seismic is only capable of resolving subsurface features that lie in the vertical plane directly underlying the geophone line. Detection of faults, traps, lenses, and other features is dependent on the size and orientation of the geologic structure.

- Time-lapse surveys require maximum repeatability between the original and subsequent surveys in terms of location of the geophones, seismic sources, and subsurface conditions. To ensure repeatability, the original, or baseline, survey must be completed in such a manner as to allow for time-lapse analysis of the subsurface. GPS sensor positioning is sometimes utilized to aid in sensor placement in order to increase repeatability of-time lapse surveys.

Sources of Error

- Glacial till; rugged terrain; poorly consolidated ground; and surface activities, such as mining, and wet ground conditions may cause acoustic coupling issues or attenuate seismic signals. Applicability and concerns should be addressed with the service company provider during planning.

- Heavy equipment, industrial operations, or mining activity may introduce noise into the seismic survey. Specific concerns should be discussed with the service company representative during planning.

- Certain geologic features, such as thick salt beds, can severely attenuate seismic signals, which may or may not be recoverable with additional processing. Specific concerns should be discussed with the service company representative during planning.

- Factors that affect the repeatability of seismic data can greatly affect monitoring capabilities (U.S. Department of Energy National Energy Technology Laboratory, 2009).

Lead Time Required to Deploy Technology

SS are generally planned months in advance so that forward modeling can be carried out; proper equipment, including geophone assemblies, seismic sources (explosives or vibratory trucks), and personnel, can be mobilized; and proper permits arranged. It is highly recommended to discuss options regarding survey type, limitations, and cost with the service provider or providers during the planning stages of a project. As seismic data can be crucial for both characterization as well as monitoring, the goals of seismic data collection and interpretation should be determined early in the project and discussed with the service company representative. Sufficient time for data processing should also be factored into the project timeline.

Case Studies and Key Findings

Time-lapse 3D seismic (known as 4D seismic) has been deployed at the landmark Sleipner CO_2 injection site offshore Norway for the purpose of MVA (Figure 25). A baseline survey was acquired in 1994, and subsequent surveys were conducted in 1999, 2001, 2002, 2004, and 2006. Seismic data have been successful at Sleipner, providing reasonable quantitative estimates of plume extents of the 10-million-tonne injection (Chadwick and others, 2009). This is, in part, because of the amenable geologic situation consisting of high saturations of low-density CO_2 in a shallow (~1000 m deep), loosely consolidated sand formation, which results in a strong contrast in travel times.

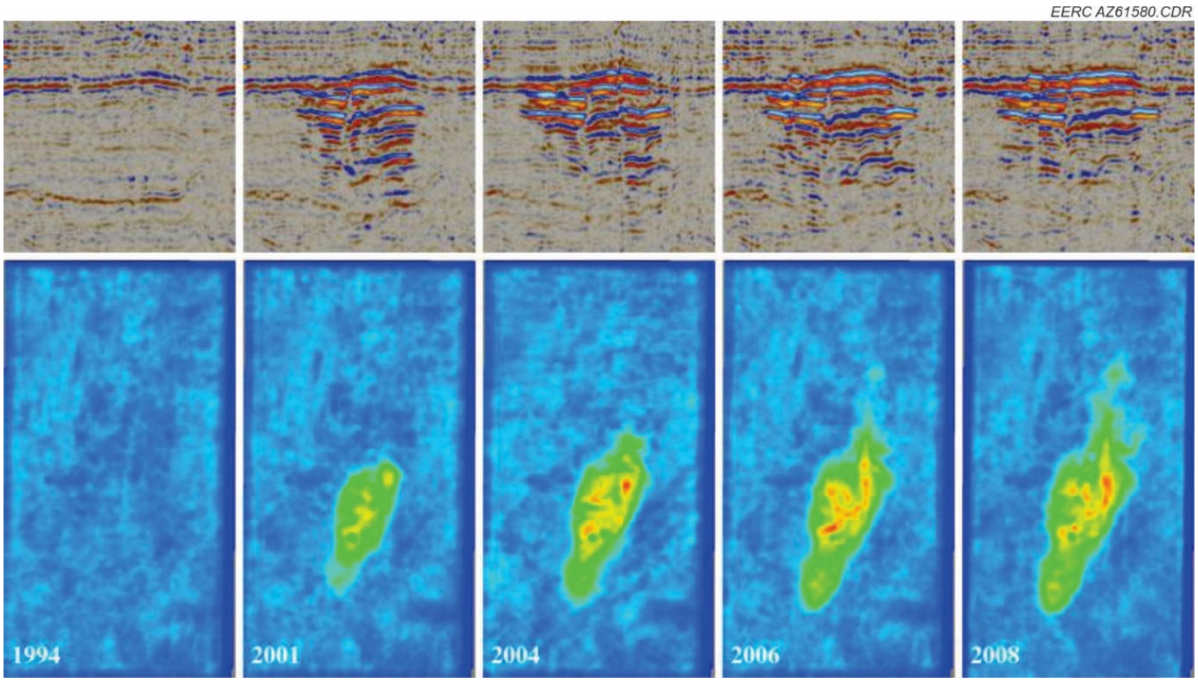

Figure 25. Time-lapse seismic response showing plume growth at Sleipner. These images are collected during repeat 3D seismic (4D) surveys (image from Chadwick and others, 2009).

4D seismic was deployed at the Weyburn Field, Canada, at 12-month intervals starting prior to CO_2 injection and running until commencement. The resultant time-lapse images (primarily seismic amplitude changes) are able to clearly map the spread of CO_2 over time within the reservoir; however, detailed quantitative estimates of CO_2 volumes were unattainable because of the multiphase fluid compositions and pressure-dependent behavior of reservoir fluids (U.S. Department of Energy National Energy Technology Laboratory, 2009).

A surface seismic network of eight broadband seismometers (Nanometrics, 2021) was placed around an array of injection and production wells at a CO_2 EOR operation in Farnsworth, Texas (Kumar and others, 2018). Of 115 events, four spatially correlated with the footprints of the CO_2 plume and pore pressure perturbation associated with Injection Well 13-10A and other neighboring injection wells (Figure 26).

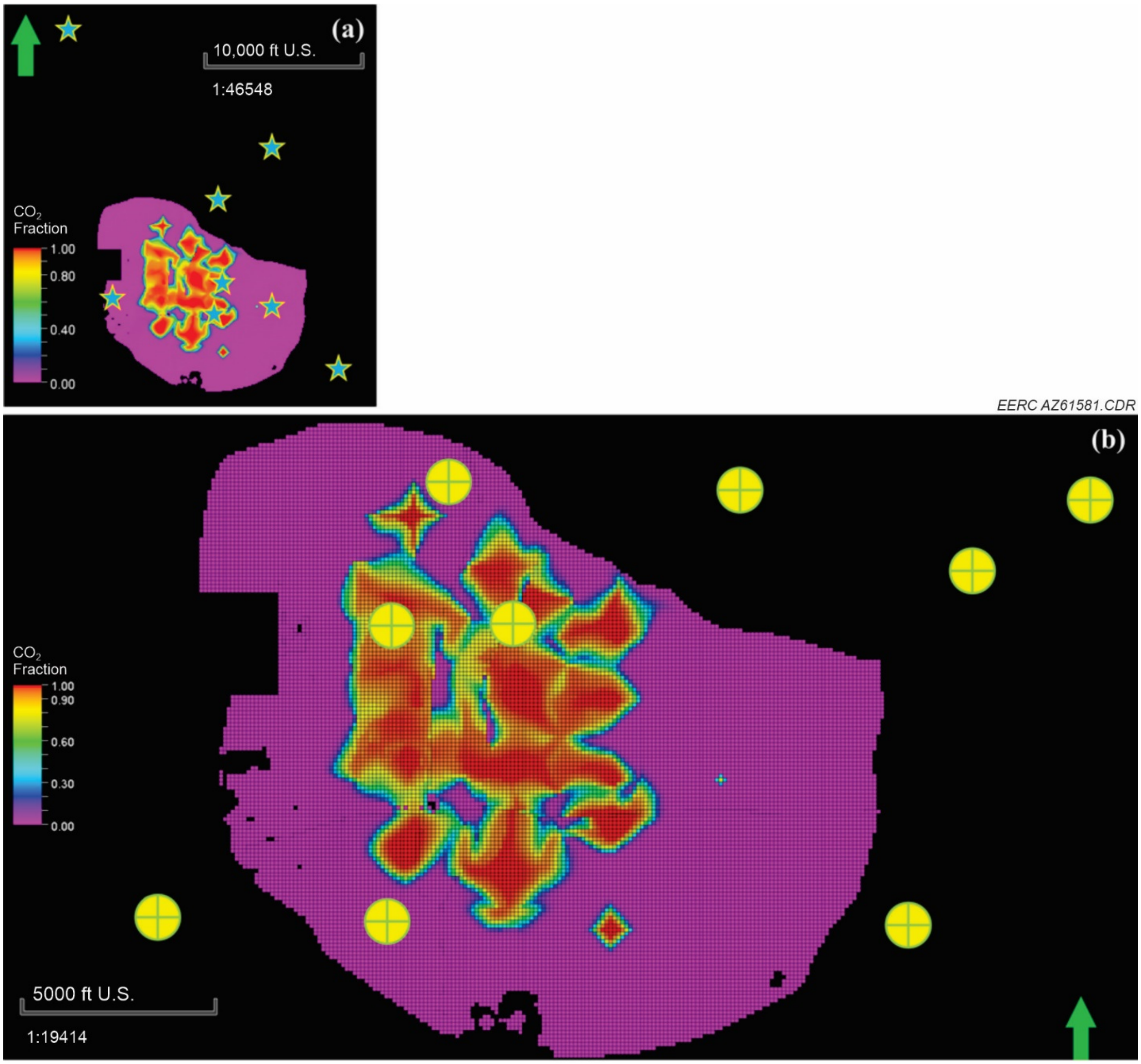

Figure 26. Map showing the reservoir model for CO_2 plume (heat map) and pore pressure variation (pink shaded region) with a) surface seismic stations on top (stars) and b) spatially overlapping and nearby low-frequency events are shown as yellow circles with a cross (image from Kumar and others, 2009).

Price Estimates

- 2D seismic (medium) per linear mile
- 3D seismic (medium to high) per square mile
- 4D seismic cost of an additional 3D seismic survey plus an additional 10% to 20% for processing costs

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SIDEWALL CORING TOOLS

Retrieving cores from deep formations is important to determining rock lithology, porosity, density, and the presence of hydrocarbons within a reservoir. Primarily drill stem cores are retrieved using drill pipe on a drilling rig; however, sidewall coring (SWC) typically is quicker and, therefore, often more cost-effective than traditional rotary coring operations but is limited to smaller core plugs retrieved from discrete depths in contrast to the continuous full-diameter cores associated with traditional rotary coring.

SWC provides a valuable contingency for core acquisition using traditional rotary coring methods in the event that unconsolidated formations, fractures, or other operational issues do not allow for drill stem core retrieval. This capability may prove valuable for many carbon storage projects operating in saline reservoirs where availability of geologic information is limited. Core and subsequent core analysis provide a host of valuable information necessary for calibrations of wireline logs, site characterization, and simulation activities.

There are two main types of sidewall coring tools (SCT). Percussion tools employ small explosive charges to punch a number of hollow steel drill bits into the rock. Once each core is tapped, vertical movement of the apparatus causes the core to break and the cores are collected. A SCT gun is an example of a percussion-type SCT.

Rotary SCTs work similarly to a drill or hole saw (Figure 27). The apparatus is lowered into a well, and a small hollow articulated coring bit protrudes perpendicularly from the apparatus. One at a time, diamond-tipped bit drills retrieves and stores a core sample.

Core samples can become damaged during percussion coring operations. Rotary drilling techniques typically produce better-quality samples with fewer microfractures that can be caused by the energy of the charges used with percussion-type SCT. Another advantage of rotary-type coring is the capability to penetrate very hard rock formations, something percussion-type SCT may have difficulty accomplishing.

Advancements in pressurized rotary sidewall coring technology create a sealed system that preserves the reservoir fluids in their as-drilled state (Halliburton, 2021). The ability to transport the in situ samples is very beneficial when it comes to conducting laboratory tests related to special and conventional core analysis. When compared to depressurized samples, the results can change drastically.

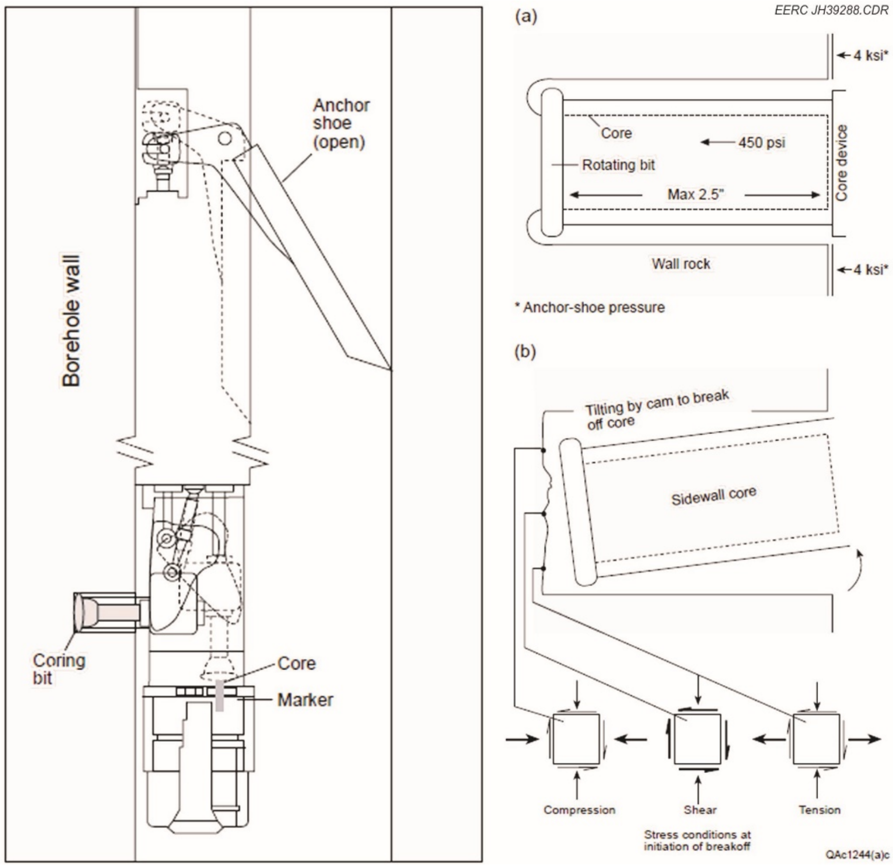

Figure 27. Illustration of a SCT collecting a core sample (Hardage and others, 1998).

Applications

- Determine and analyze lithology.
- Mineralogical analysis.
- Determination porosity and permeability.
- Secondary porosity analysis (Schlumberger, 2004).
- Paleontological dating.
- Determine presence of fluids (gas, oil, water) within the rock.
- Determine storage capacity and fluid flow.
- Determine clay content (Schlumberger, 2004).

- Determine grain density (Schlumberger, 2004).
- Detect fracture occurrence (Schlumberger, 2004).
- Gather reliable data for rock mechanical analysis necessary for hydraulic fracturing design, wellbore stability analysis, and sand potential prediction (Halliburton, 2008).
- Additional standard and specialized core analysis.
- Analyze grain size, log calibration NMR, mechanical properties, RES), and capillary pressure (Schlumberger, 2012).

Deployment Logistics

Operating Environment: Openhole, Downhole

Tool Limitations

- Core intervals must be selected based on previously run logs and correlated using GR data.
- There exists the ability to orient the core and confirm the interval samples if an electric borehole imaging tool log is run after core retrieval.
- Common sample size limitations are typically between 0.92 and 1.50 inches in diameter and between 1.75 and 2.0 inches. Larger, less common sample sizes are typically 1.5 inches in diameter and 2.5 inches in length (Schlumberger, 2012; Baker Hughes, 2020).
- Typically, the maximum number of core samples ranges from 30 to 75 per run.
- Coring time ranges from 3 to 5 minutes per sample (Schlumberger, 2004).
- Typically, the minimum wellbore diameter required for SCT operations is greater than 5.5 inches and varies by service provider (Schlumberger, 2004).
- Differential sticking is a concern during SCT operations because of the time the tool remains stationary. Differential sticking is probable when overbalanced conditions occur (hydrostatic pressure is greater than formation pressure), which causes the tool to become stuck to the borehole wall because of the differential pressure between the borehole and the formation. The risk of differential sticking increases with the degree of overbalance in high-permeability formations or when the tool is stationary for a long period of time. If the tool becomes stuck, fishing operations may need to be employed, which can become costly. Concerns should be addressed with the logging service company representative prior to or upon arrival at location.

Lead Time Required to Deploy Technology

SCTs are not considered a standard openhole logging service. Typically, SCTs require specialized equipment and a specialist on location to conduct the coring; therefore, tool and personnel availability are issues which should be addressed in the planning stages of an evaluation program. The planning of this type of program should be completed a few weeks to a few months prior to deployment. Additionally, special care should be taken to keep the service company informed of drilling progress to minimize standby time for the rig prior to the start of the coring run and for the service company. Not all openhole service companies may have the capability to run SCTs, and availability should be discussed with specific service providers.

In order to ensure core from the desired intervals is obtained, the coring program should be discussed thoroughly with the service company representative during the planning stages and again prior to arrival on location. The coring program should include the estimated number of core samples desired, reservoir conditions, and anticipated hole conditions. It may be necessary to have a qualified on-site geologist or engineer familiar with the stratigraphy available to pick specific core depths of interest from the logs conducted on previous runs.

Picking the core points from the log data ensures that the proper depth is cored and a representative core specimen is obtained. This method is often necessary because of depth shifts between wireline logs, drillers' depths, and mud logs, which could range between a few inches to tens of feet. The depth shifts are caused by tension issues, stretch of drill pipe and wireline, lag time for mud logging, and/or resolution of the depth measurement. A GR log is run in conjunction with the coring tool so correlation between the logs and the coring tool can occur in real time using the GR log.

Case Studies and Key Findings

Coring is a common practice in the oil and gas industry and is a necessary component of CO_2 characterization programs. SC or rotary drill stem cores are two methods available for collecting core samples.

A study regarding stimulating Canyon Sands using CO_2 foam and methanol injection was conducted on the Conger (Penn) Field in Sterling County, Texas. In this case, the core samples obtained using SCT were used to analyze the clay content, grain size and density, and permeability of the Canyon gas sands (Craft and others, 1992).

Two experiments were conducted evaluating the results on the use of CO_2 as an EOR agent in preserved sidewall shale cores (similar to Bakken Shale [Hoffman 2012]) saturated with oil (Tovar and others, 2014). CO_2 injection through the matrix was not possible because of the low permeability. Instead, high-pressure CO_2 was circulated through hydraulic fractures that were simulated by glass beads. The change in CT number was tracked over time during both experiments. The attenuation of x-ray intensity when passing through a material is a function of the density and composition of such material, and it is expressed as CT number. The results from this process were promising, with oil recovery estimated to be between 18% to 55% of original oil in place.

Price Estimates

- 50 sidewall cores (medium)

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SONIC

Sonic (SON) tools use acoustical measurements to determine lithology, stress fields and orientations, porosity, permeability, pore pressure, and other rock properties. Two primary categories of SON tools are commercially available. Basic or traditional SON logs measure the interval transit time (reciprocal of velocity measured in microseconds per foot) of a compressional wave traveling through a formation in order to interpret rock properties near the wellbore. Basic SON measurements are most commonly used to produce a sonic porosity for a formation and to translate SS data, recorded in the time domain, to a depth domain (Schlumberger, 2010).

Advanced SON tools allow for the azimuthal measurement and analysis of compressional, shear, and Stoneley acoustical waves in order to provide advanced reservoir characterization interpretations, such as 3D rock mechanics, determination of formation heterogeneity through stress anisotropy detection, characterization of reservoir for gas zones, and permeability estimates in addition to basic sonic capabilities (Halliburton, 2010) (Figure 28). Some advanced SON tools additionally allow for limited ABC evaluations, such as fracture detection. Advanced SON tools can be utilized in mechanical earth modeling to improve drilling and completions designs when drilling takes place outside of traditional oil and gas fields with lesser-known parameters. SON tools can be used to describe rock strength, 3D elastic properties, and stress direction as part of an iterative process to provide predictive models of the lesser-known area.

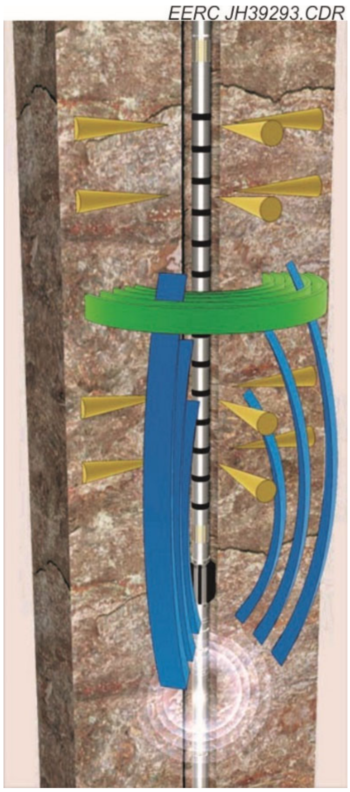

Figure 28. Image depicting an advanced SON tool capable of recording axial, azimuthal, and radial measurements of compressional, shear, and Stoneley waves (Schlumberger, 2010).

Applications

- Analyze compressional, shear, and Stoneley waves (Schlumberger, 2007; Halliburton, 2010).
- Analyze porosity and secondary porosity (Schlumberger, 2007; Asquith and Krygowski, 2004).
- Analyze permeability (Schlumberger, 2007; Halliburton, 2010).
- Analyze pore pressure (Schlumberger, 2007; Schlumberger, 2008; Bérard and others, 2007).
- Analyze lithology (Schlumberger, 2007).
- Detect gas (Schlumberger, 2007).
- Convert synthetic seismograms, seismic correlation/calibration, and time/depth (Schlumberger, 2007; Weatherford, 2008, 2010; Baker Hughes, 2010a,b).
- Identify 3D rock mechanics, including Poisson's ratio, shear modulus, Young's modulus, bulk modulus, and bulk compressibility (Weatherford, 2008).

- Detect and orient stress anisotropy and fracture anisotropy (Schlumberger, 2007, 2008, 2014; Halliburton, 2010; Weatherford, 2008).

- Identify hydrocarbons.

- Identify CO_2 and CO_2 saturations based on SON velocity (Mito and Zue, 2010; Freifeld and others, 2008; Nakatsuka and others, 2010).

- Critical real-time answers, including pore pressure prediction, seismic time–depth tie, and borehole stability issues addressed by compressional and shear slowness measurements (Baker Hughes, 2020; Schlumberger, 2019; Weatherford, 2017a,b).

- Determine structural information, such as the dip and azimuth of bedding, fractures and faults (Schlumberger, 2021).

Deployment Logistics

Operating Environment: Openhole, Cased Hole, Downhole

Tool Limitations

- Some technologies attempt to operate close to the tool's low-frequency limit, or they depend on previously acquired formation information to anticipate formation slowness prior to data evaluation (Schlumberger, 2005).

- The borehole must be fluid-filled for acoustic coupling to occur (PETROLOG, 2006).

- The depth of investigation for SON measurements varies based on formation properties; however, they typically are a few inches from the borehole wall.

- Some SON services may require other logs or core analysis for calibration or interpretation purposes. Applicability should be discussed with the service provider prior to deployment.

- Many SON applications are only available using advanced SON tools. Applicability should be discussed with the service provider prior to deployment.

- SON velocity variations during a steamflood are on the order of 10% (Schlumberger, 2010). Variations in SON velocity may be below the detection limits of SON tools in some circumstances. Applicability should be thoroughly evaluated and discussed with the service provider prior to deployment.

- SON velocity sensitivity to CO_2 is greatly diminished at saturations above 20% (Nakatsuka and others, 2010).

- ABC SON reservoir evaluation capabilities are limited and should be discussed with the service provider prior to deployment.

Sources of Error

- Tool sticking can decrease data quality (Baker Hughes, 2010a,b).

- Noise caused by borehole rugosity or cycle skipping caused by gas in the borehole or poor tool centralization can attenuate the signal causing log quality issues (PETROLOG, 2006).

- SON measurements do not detect secondary porosity; therefore, SON porosity is a measure of interconnected porosity only and does not include vugs or other isolated nonconnected porosity. Secondary porosity can, however, be estimated by comparing SON porosity measurements with other porosity measurements (Weatherford, 2008).

- SON porosity reads high in gas and shale because shale and gas transit times are greater than those of fluid.

Lead Time Required to Deploy Technology

Basic SON measurements are considered a standard openhole reservoir evaluation logging service. Basic SON services should be selected during the initial planning of the logging program a few weeks to a few months before the estimated logging date; however, since they are a basic service, they may be available on-demand with as little as 6 hours of lead time.

Advanced SON measurements are considered specialized measurements and may require 1 month of lead time to ensure tool availability; however, many service providers have advanced SON tools on hand and may require a little as 6–24 hours of lead time. Not all service companies have these capabilities; therefore, any advanced SON measurement and its applicability should be discussed with the potential service provider during the initial planning stages well in advance of the actual deployment date. ABC capabilities are limited and should be discussed with the service company provider as needed.

Case Studies and Key Findings

Investigations into using P-wave sonic velocity and RES for detecting and monitoring CO_2 were conducted at both the laboratory- and field-scale. Results indicated P-wave velocities became less sensitive when CO_2 saturation increases above 20%. Time-lapse SON logging results agreed well with laboratory results (Xue and others, 2006, 2009; Förster and others, 2006; Nakatsuka and others, 2010).

A study investigated the geomechanical property changes taking place with CO_2 injection in Delhi Field in northern Louisiana. SON log data (compressional and shear wave velocities [Vp, Vs]) were available in only two wells before the CO_2 injection in the study area. In the absence of SON logs, other available wireline log data were utilized to obtain synthetic elastic rock properties using fundamental petrophysical correlations and neural network approach (Guan and Tutuncu, 2012). The coupled approach could be used to identify any seal breach issues and near-well integrity problems in CO_2 EOR operations.

An onshore CO_2 storage experiment located in Ketzin, Germany, was led by the German Research Center for Geosciences, also a part of the research consortium, CO_2SINK. A maximum of about 60,000 metric tonnes of CO_2 was injected over the life of the project. Data acquired in the Ktzi201 well consisted of dipole SON, RES borehole-wall imaging, in situ pore pressure measurements, and mechanical core tests (Sinhaa, and others 2010). Results from the stress inversion from borehole SON data were consistent with the calibrated poroelastic model and previously reported stress estimates in the same field (Röckel and Lempp, 2003). They were integrated in a mechanical model that described in situ rock stress, fluid pressure, and the poroelastic and strength properties of the formations along the Ktzi201 well.

Price Estimates

- Basic SON (low)
- Advanced SON (low–medium)

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SPONTANEOUS POTENTIAL

Spontaneous potential (SP) is a measurement of the natural difference in electrical potential in millivolts (mV) between a movable electrode in the borehole and a fixed reference electrode on the surface (Schlumberger, 1989).

The SP curve shows significant deflection opposite permeable beds; however, the measurement itself is relative. Quantitative results are calculated from the magnitude of the deflection rather than from absolute values. The SP deflection can be either positive or negative and is dependent on the salinity of the formation water and the mud filtrate. The magnitude of the deflection depends primarily on the salinity contrast between drilling mud and the formation water and the clay content of a permeable bed (Schlumberger, 1989, 2010).

Applications

- Differentiate potentially porous and permeable reservoir rocks from nonpermeable clays and shales (Schlumberger, 1989).
- Define bed boundaries and permit correlation of beds between wells (Schlumberger, 1989).
- Give a qualitative indication of formation clay content (Schlumberger, 1989, 2010).
- Aid in lithology identification (Figure 29) (Schlumberger, 1989; Varhaug, 2016).
- Determine formation water RES (R_w) (Schlumberger, 1989, 2009).
- Estimate formation water salinity (Schlumberger, 2010).

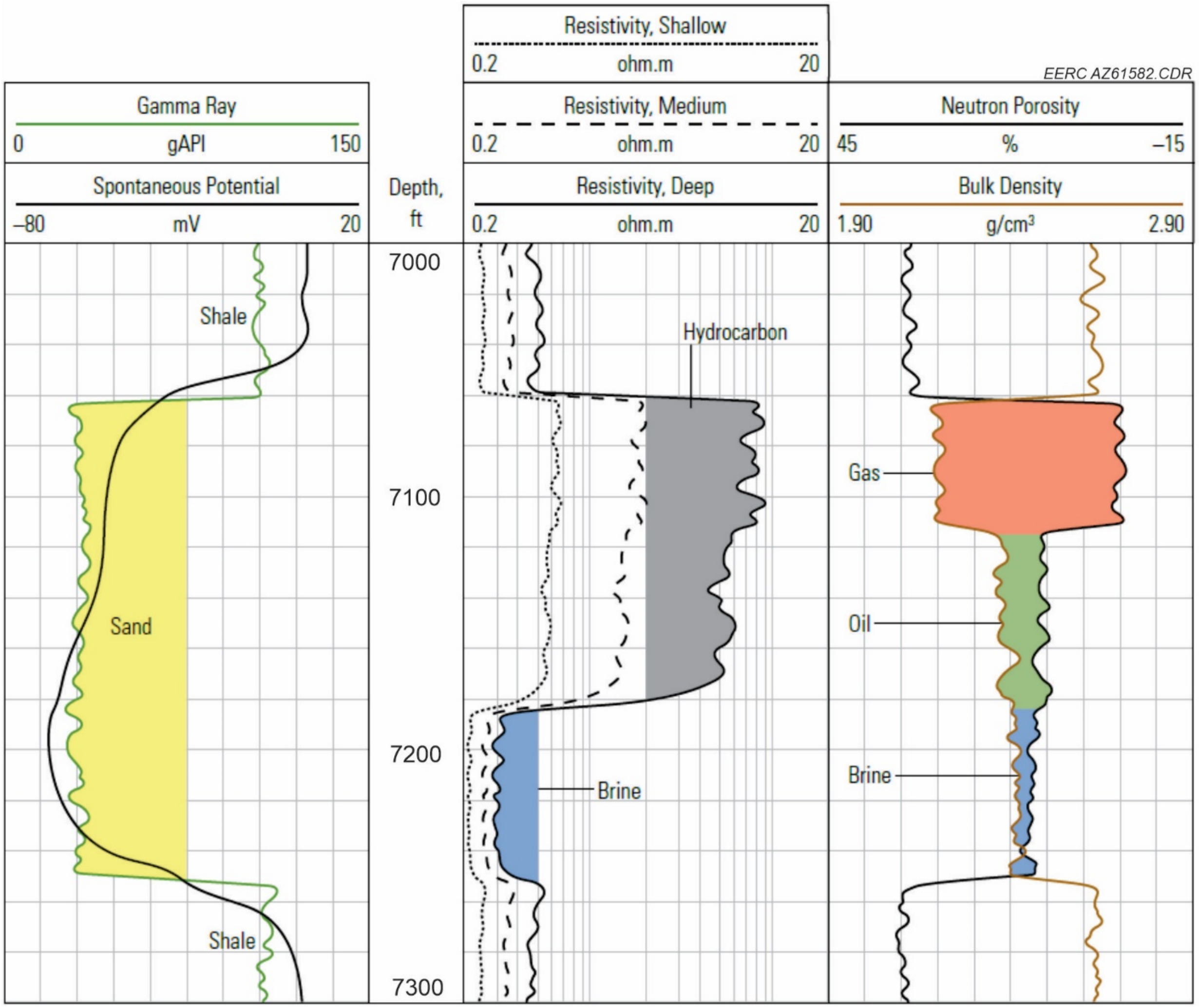

Figure 29. A basic well log representation, including SP, GR, RES, neutron and density curves. The SP curve generally follows a trend similar to that of the GR (Varhaug, 2016).

Deployment Logistics

Operating Environment: Openhole, Downhole

Tool Limitations

- SP cannot be measured in nonconductive fluid systems (Schlumberger, 1989).
- SP measurement is only possible in formations having a certain minimum permeability; a fraction of a millidarcy (mD) is sufficient (Schlumberger, 1989).
- If the RES of the mud filtrate and formation water are about equal, the SP deflection will be small, and the curve will be rather featureless (Schlumberger, 1989).

Sources of Error

- Mud characteristics should be kept constant during the drilling process when SP is needed to determine R_w. Field experience has shown that when there is a significant change in the mud used during drilling, a period of time is necessary for the recorded SP curve to reflect the characteristics of the new mud (Schlumberger, 1989).

- Magnetization of the winch drum or intermittent contact between the logging cable and the casing may cause spurious spikes or a sinusoidal SP response (Schlumberger, 1989).

- Direct current flowing near formations and bimetallism can affect the SP measurement (effect is increased in highly resistive formations) (Schlumberger, 1989).

- Leaky power sources, stray voltage, cathodic protection, proximity to power lines, and pumping wells may affect the SP curve. Properly locating, grounding, and isolating the grounding electrode will minimize this potential (Schlumberger, 1989).

- Reference electrode must be electrically grounded and isolated from voltage sources.

Lead Time Required to Deploy Technology

Typically, SP logging services are included during the initial planning of the logging program a few weeks to a few months before the estimated logging date; however, SP is a standard logging service for many service companies and could potentially be ordered on-demand with as little as 6 hours of lead time.

Case Studies and Key Findings

Accurate R_w values needed to be obtained from the Minnelusa Formation of the Powder River Basin, Wyoming. R_w was frequently low when computed from an SP log compared to directly analyzing the water samples. Two static spontaneous potential (SSP) techniques and an interpretive equation proved to increase the accuracy of R_w derived from SP measurements (Policky and Iverson, 1988). The SSP techniques developed for the Minnelusa Formation evolved to the Opeche Shale method and the dolomite “stringer” method. Work developed in these formations can also be applied to additional horizons, fields, or basins for calculating R_w from the SP log.

Price Estimates

- SP (low)
- SP is typically included as part of many basic resistivity logging service at no additional cost; however, depending on the logging program, SP may be run as an optional stand-alone service.

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Ultrasonic imaging (UI) tools typically utilize a rotating ultrasonic transducer to provide 360° coverage of the borehole or casing and then analyze the acoustic signal (both amplitude and transit time) within the borehole for both openhole and cased-hole applications. Openhole applications are related to formation evaluation and are similar to electrical borehole imaging tools (Figure 30), whereas cased-hole applications are related to cement evaluation and casing integrity (Halliburton, 2010). While UI can typically be used in any borehole fluid or mud type, specific tools are required for either openhole or cased-hole applications and should be discussed with the service company provider during the initial planning stages (Schlumberger, 2002; Baker Hughes, 2008).

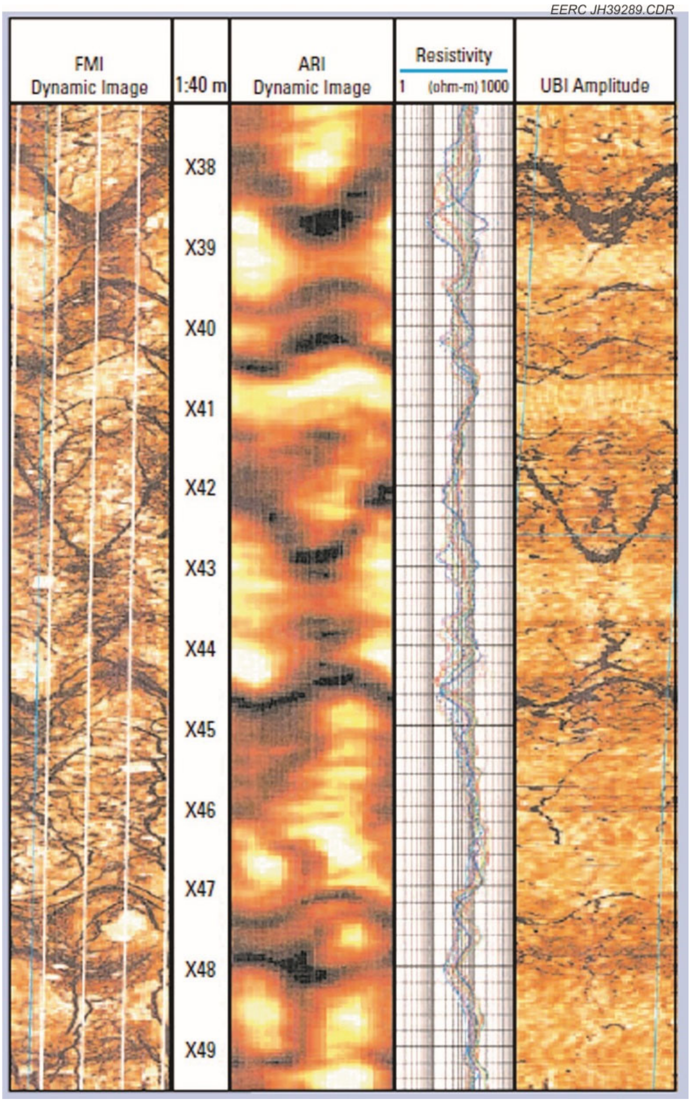

Figure 30. Openhole well log examples comparing different types of imaging logs. The left and center images depict electrical borehole imaging logs, whereas the right is an ultrasonic log (Schlumberger, 2010).

Well integrity-monitoring applications may prove useful for CO_2 geologic storage applications in assessing risk for wells penetrating a storage formation in order to determine the likelihood of potential leakage, to target wells for remediation, and to monitor ongoing corrosion in injection wells.

Applications

Openhole Applications

- Analyze structural bedding and dip (Schlumberger, 2002, 2007, 2021; Halliburton 2021; Baker Hughes, 2020).
- Identify and analyze fractures, including differentiating closed and open fractures (Schlumberger, 2002, 2007, 2021; Halliburton 2021; Baker Hughes, 2020).
- Analyze borehole shape, including keyhole wear, breakout, and shear sliding (Schlumberger, 2002, 2010, 2021; Halliburton 2021; Baker Hughes, 2020).
- Calculate borehole radius and cement volumes (Schlumberger, 2002, 2021; Halliburton 2021; Baker Hughes, 2020).
- Analyze borehole stability and stress, including horizontal stress determination (Schlumberger, 2002, 2007, 2010, 2021; Halliburton 2021; Baker Hughes, 2020).

Cased-Hole Applications

- Perform 360° analysis of cement bond (Baker Hughes, 2008; Schlumberger, 2009, 2017).
- Determine annulus cement strength (Baker Hughes, 2008; Schlumberger, 2009, 2017).
- Determine presence of a microannulus (Baker Hughes, 2008; Schlumberger, 2009, 2017).
- Confirm hydraulic isolation (Schlumberger, 2007, 2009, 2017).
- Map annulus material as solid, liquid, or gas, and determine the acoustic velocity of the annulus material (Schlumberger, 2007, 2009, 2017; Baker Hughes, 2008).
- Determine borehole fluid properties (Schlumberger, 2007, 2009, 2017).
- Locate and image channels or defects in annular isolation material (Schlumberger, 2007, 2009, 2017; Baker Hughes, 2008).
- Visualize position of casing within the borehole (Schlumberger, 2007, 2009, 2017).
- Perform casing thickness analysis for collapse and burst pressure analysis (Schlumberger, 2007, 2009, 2017).

- Determine casing internal and external diameters for monitoring purposes and to locate and quantify casing wear damage or metal loss caused by milling, drilling, fishing operations, internal or external scale buildup, casing corrosion, and casing damage or deformation (Schlumberger, 2007, 2009).

- Locate and identify casing holes and perforated intervals (Schlumberger, 2007, 2009).

- Identify casing profiles and weight changes (Schlumberger, 2007, 2009).

Deployment Logistics

Operating Environment: Openhole, Cased Hole, Downhole

Tool Limitations

- The resolution of UI tools is often inadequate to detect "pure" fractures unless they are very wide. However, since the drilling process tends to chip and break the formation at the edge of a fracture, the ultrasonic tool can often discern fractures by associated surface rugosity. Open vs. closed fracture analysis requires an additional electrical borehole imaging input (Schlumberger, 2002, 2007).

- The borehole must be fluid-filled for acoustic coupling to exist (PETROLOG, 2006).

- UI tools are primarily utilized to evaluate the cement-to-casing interface. Bond log tools are typically required for cement to formation bond evaluation.

Sources of Error

- Borehole rugosity can affect the reflection amplitude of the signal in openhole environments (Schlumberger, 2002).

- Accurate measurement of fluid properties is an important aspect of accurate and successful ultrasonic well integrity measurements. Wellbore fluid needs to be clean and consistent in order to estimate the acoustic impedance of the fluid; therefore, it is important that the wellbore and wellbore fluid are cleaned to ensure that fluid property measurements are successful in existing or vintage wellbores. Concerns should be discussed with the service company representative during the planning stages (Duguid and Tombari, 2010).

- Tool sticking and pulling can cause a decrease in data quality (Baker Hughes, 2010).

- Mudcake influences the UI by attenuating the ultrasonic signal, slightly decreasing the measured radius (Schlumberger, 2002).

- Transducer sizing is related to borehole size for both cased-hole and openhole applications and should be discussed with the service provider in the planning stages to ensure proper transducer selection.

Lead Time Required to Deploy Technology

UI is not considered a standard openhole reservoir evaluation service nor a standard cased-hole evaluation service. Typically, UI services are selected during the initial planning of the logging or evaluation program a few weeks to a few months before the estimated logging date to ensure tool availability. During the initial planning stages, drilling and/or completion information and applicability should be discussed with the service company representative to ensure that the operating environment is compatible with the tool selected and to ensure tool availability. Not all service companies may have UI capabilities.

Case Studies and Key Findings

A study using UI was conducted to investigate well integrity for technical and regulatory considerations for CO_2 injection wells. UI was used in combination with a traditional cement bond log tool to evaluate the cement around the well casing. UI was valuable in detecting small leaks in the casing, thereby illustrating UI's potential for detecting small leaks in CO_2 injection applications (Talibuddin and Cutler, 2010).

A study conducted in the Permian Basin of West Texas focused on understanding water production zones so that they could be properly isolated to reduce oil-processing costs (Logan and others, 2000). UI was employed to evaluate the cement integrity within the well prior to changing the production profile (Logan and others, 2000).

At Nagaoka, the first pilot-scale CO_2 injection site in Japan, well integrity was examined by ultrasonic and sonic logging (Nakajima and others, 2013). Analysis from the ultrasonic logging suggested that there was no severe damage or deformation in the casing at reservoir depth, not much change in casing thickness, and no clear evidence that the cement impedance behind the casing at the reservoir depth had changed. These results showed that there is no clear evidence of CO_2 leakage at Nagaoka and support the argument that underground CO_2 storage is a safe practice.

Price Estimates

- UI cased-hole or openhole applications (low)

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