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A Review of Well Integrity Based on Field Experience at Carbon Utilization and Storage Sites

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A R T I C L E I N F O

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A B S T R A C T

Maintaining well integrity is critical to the success of geologic carbon storage (GCS) and carbon dioxide enhanced oil recovery (CO_2-EOR) operations. Wells that experience leakage because of integrity issues can potentially become a risk to the environment or human health if they release previously captured CO_2 back into the atmosphere or into freshwater aquifers. There are many GCS and CO_2-EOR sites in operation around the world. However, well integrity experiences at these sites are not widely documented in the public domain. This study details findings from a survey of well integrity experiences elicited from operators of GCS and CO_2-EOR sites. The goal of the survey was to obtain information about site characteristics and operator experiences with well integrity, monitoring methods, and risk assessment of legacy wells. Literature relevant to the survey questions was also reviewed and summarized to provide context for survey responses and identify areas where field experiences with well integrity do and do not align with the current state of research. We highlight the current state-of-practice, identify research needs, and provide context for future interactions between researchers, operators, and regulators on issues related to well integrity.

1. Introduction

Well integrity generally refers to the ability of a well to produce or inject fluids in a controlled manner while preventing the unwanted upward migration of fluids outside of the well system. The Norsk Sokkels Konkurranseposisjon (NORSOK) standards define well integrity as "application of technical, operational, and organizational solutions to reduce the risk of uncontrolled release of formation fluids throughout the entire life cycle of the well" (NORSOK, 2013). Similarly, well integrity is defined by the American Petroleum Institute as "the design and installation of well equipment to a standard that protects and isolates useable quality groundwater, delivers and executes a hydraulic fracture treatment, and contains and isolates the produced fluids" (American Petroleum Institute, 2016). Modern wells are designed with multiple barriers to create a controlled pathway for injection or production, and to isolate fluids in the formations along their depth. Once installed, wells are subject to chemical and mechanical stresses in the subsurface, which can reduce the effectiveness of emplaced barriers and may ultimately lead to integrity loss. These stresses may be amplified at geologic carbon storage (GCS) and carbon dioxide enhanced oil recovery (CO_2-EOR) sites where injection wells experience large temperature and pressure variations, higher injection pressures, and reactions between CO_2-brine mixtures and well components (Carroll et al., 2017, Carroll et al., 2016, IEAGHG Well, 2018).

Wells with compromised integrity may not prevent the upward migration of injected CO_2 and other formation fluids. Leaked fluids can degrade air quality and act as greenhouse gases, if released into the atmosphere, or contaminate potable groundwater resources if they escape into the subsurface (Carroll et al., 2014, Xiao et al., 2016, Pawar et al., 2006). Maintaining well integrity is critical to the success of GCS

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and CO_2-EOR operations (Pawar et al., 2014, Apps et al., 2010, Viswanathan et al., 2008, Lackey et al., 2019, Klusman, 2003). To date, field-based observations of well integrity have been predominantly reported in the context of oil and gas production operations (Bachu, 2017, Watson and Bachu, 2009, Wisen et al., 2020, Lackey et al., 2017). Most reported instances of oil and gas well integrity loss have indicated only a small degree of leakage (Bachu, 2017, Watson and Bachu, 2009, Wisen et al., 2020), which are typically repaired or managed at the wellhead and do not pose an environmental or human health risk. However, more severe cases of well integrity loss have resulted in contamination of shallow freshwater aquifers and substantial emissions to the atmosphere (Lackey et al., 2017, Jordan and Benson, 2009). Under rare circumstances, extreme instances of integrity loss have also led to catastrophe (Lindeberg et al., 2017, Hickman et al., 2012).

Over the past 20 years, the number of GCS demonstration projects and CO_2-EOR operations has grown significantly. These operations generate data, information, and institutional knowledge pertinent to operation and performance of injection, monitoring, and legacy wells. Unfortunately, such well integrity knowledge is often retained by individual institutions and reported within individual, regional, or national jurisdictions to satisfy specific regulatory requirements. As such, there is currently no common source from which to draw insights and gain a better understanding of well integrity trends and challenges presented by GCS and CO_2-EOR operations to identify relevant research needs. To develop such a source of information, we assembled a survey and disseminated it to operators of GCS and CO_2-EOR sites to gather data about their experiences with well integrity. Literature relevant to the survey questions was also reviewed and summarized to provide context for survey responses and identify areas where field experiences with well integrity do and do not align with the current state of research. These findings will complement other efforts to identify research topics like the prioritized research directions from the Mission Innovation Carbon Capture, Utilization, and Storage Expert's Workshop (Accelerating Breakthrough Innovation in Carbon Capture, 2021).

2. Methods

A survey targeted for operators of GCS and CO_2-EOR projects was designed as part of this study. The goal of the survey was to gather information about well integrity from a variety of sites to identify best practices and understand where better information is needed to reduce and manage well leakage risks and ensure effective long-term CO_2 storage in geologic formations. The survey focused on understanding minor to moderate phenomena and events related to well integrity encountered in the course of business-as-usual operations for GCS and CO_2-EOR scenarios.

The survey designed for this study consisted of 41 questions organized in four sections: 1) general site characteristics, 2) experiences with well integrity issues, 3) commonly used well integrity monitoring methods, and 4) risk assessment methodologies. The questions were vetted by experts in the oil and gas industry and the United States Department of Energy (US DOE) prior to its solicitation. The online survey software company Survey Monkey Inc. (Survey Monkey, 2020) was used to create the online version of the survey and gather responses. A copy of the survey is included in Appendix S1. Survey responses were received in an anonymous format to maintain confidentiality of the respondents and their sites and to encourage candid feedback.

Potential survey respondents were identified using publicly available information and contact lists maintained by the National Energy Technology Laboratory (NETL) and SINTEF. Surveys were disseminated to 55 prospective site respondents internationally in April 2019 and responses were collected continuously until August 2020 (Fig. 1). In total, 22 survey responses were collected from operators of GCS and CO_2-EOR sites. Compiled data summarizing survey responses were downloaded from the

SurveyMonkey Inc. website and analyzed for this manuscript. Current literature relevant to the survey questions was also reviewed and summarized.

3. Results

3.1. Survey context

We gathered information about the key features of each respondent's project, namely: site description, injection details, and reservoir properties to understand the context of the responses and determine the extent to which collected responses represent the different attributes of CO_2 storage being considered, e.g., CO_2-EOR vs. GCS, onshore vs. offshore, pilot scale vs. commercial scale. Of the 22 survey respondents, seven operated CO_2-EOR sites and ten operated GCS sites. Some of the other respondents reported operating sites that combined CO_2-EOR and GCS. Most respondents operated onshore sites, and only four offshore site operators responded. The injection characteristics spanned different scales for time, volume, and rate of injection. The typical survey respondent operated at a site targeting a reservoir more than 1000 m deep, with hydrostatic or below hydrostatic pre-injection reservoir pressure, and reservoir temperature below 100°C. The reservoir rock was typically sandstone and less frequently carbonate, while the caprock

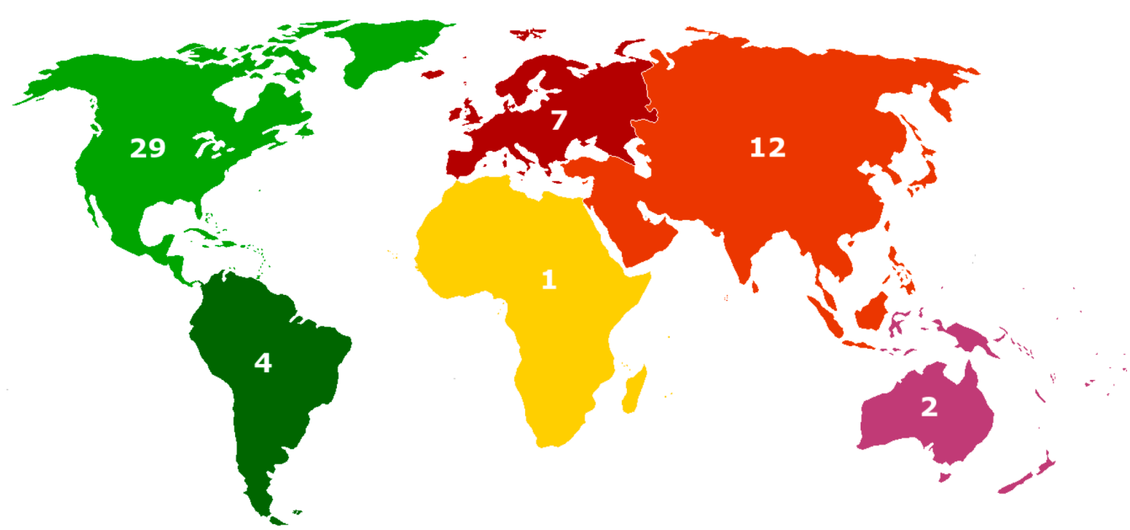

Fig. 1. Distribution of the 55 potential survey respondents on each continent. Image modified from Wikimedia Commons. (Naylor, 2006)

typically was shale or evaporite. Further details about the responses can be found in the report by (Iyer et al., 2020).

Similar background information on 50 CO_2 storage sites listed in the NETL CCS database National Energy Technology Laboratory, 2020) was gathered to understand whether the survey respondents formed a representative sample of GCS and CO_2-EOR operations (Iyer et al., 2020). The 50 sites were chosen based on the ease with which information could be obtained from public reports, presentations, and journal articles. Review of this information shows that a typical site profile for a GCS/CO_2-EOR site is similar to the typical site profile from the survey responses. One exception was that none of the survey responses were from coal bed CO_2 storage sites. The lack of survey response from this type of site is not a significant shortcoming as several barriers, including technological challenges, still need to be overcome before coal bed CO_2 storage is proven to be commercially viable. (Sloss, 2015)

3.2. Well construction

Proper well construction is critical to the establishment and maintenance of the integrity of a well over its lifetime. Issues that arise during well construction can immediately impair the integrity of a new well or cause higher rates of material degradation, which could eventually result in integrity loss. Survey respondents were asked to estimate the negative impact of a variety of well construction issues on well integrity by classifying them as having major, medium, low, or no impact (Fig. 2a). The well construction issues considered were related to drilling (loss of circulation, borehole instability, hole/trajectory deviation), cement installation (defects caused by pumping and displacement, mud contamination), or casing installation (stuck pipe, casing deformation, drillpipe failure).

No or low impact was the most common response for all well construction issues. However, each individual issue was categorized by at least one respondent as having a major negative impact on well integrity. Defects in annular cement caused by imperfect cement pumping and displacement issues, and loss of circulation were two of the most important well construction issues based on the survey responses, with five respondents categorizing them as having a medium or major impact on well integrity. Surface casing vent flow caused by shallow coals (medium impact) and behind casing instrumentation (major impact) were issues listed by survey respondents in the "Other" category (Fig. 2a).

We were unable to find a systematic study that has evaluated the impact of well construction issues on well integrity. Studies that reviewed large regulatory databases have typically correlated well integrity issues with general well attributes like age, orientation, cement height, type, and status (Section 3.7). It is likely that a lack of publicly available data describing the specific well construction issues faced by drillers during well installation has limited the scope of these studies.

Despite the lack of systematic studies, poor zonal isolation with cement is generally considered the primary well construction issue of

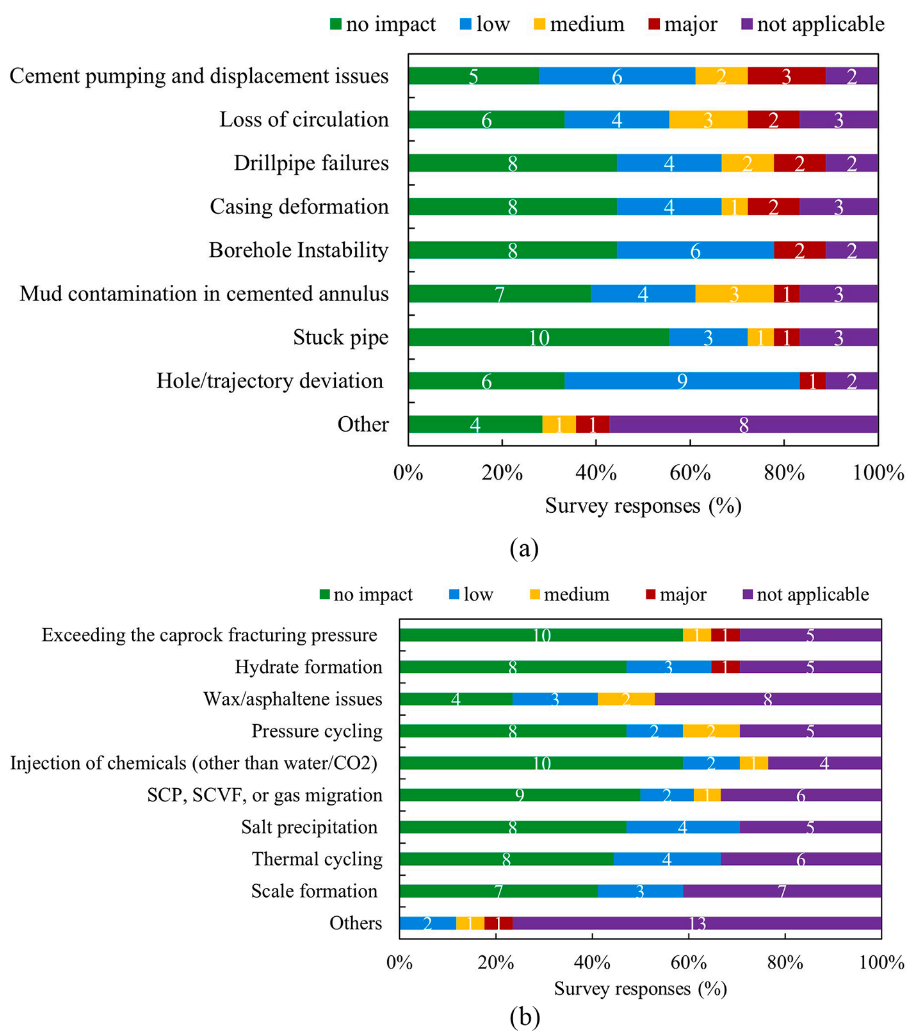

Fig. 2. Survey responses estimating the (a) negative impact of different well construction issues on well integrity and (b) negative impact of operational issues. The issues are listed sequentially by the number of respondents that classified them as having major, medium, and low negative impact.

concern at CO_2 injection sites (Loizzo et al., 2013). The survey responses partly aligned with this conclusion and identified defects in annular cement caused by cement pumping and displacement issues as the well construction issue that would have the greatest impact on well integrity (Fig. 2a). During a cement job, uniform flow and displacement of fluids throughout the annular space are crucial factors that determine the integrity of the cement sheath (Lavrov and Torsæter, 2016). Mud channels, and other annular cement defects left in the cemented annulus after installation can serve as pathways for injected CO_2. Reaction between acidic CO_2 saturated brine and well components can amplify the adverse effects of poor cement jobs (Carroll et al., 2016).

Specific instances of well construction issues impacting well integrity at CO_2 storage sites have been reported in the literature. Loizzo et al. (Loizzo et al., 2013) evaluated the integrity of an old production well, which was considered as a CO_2 injector, in the Rousse field (France). Discontinuous pockets of fluids were detected throughout the cement sheath, possibly due to ineffective mud removal. These fluid pockets were almost always associated with the narrow side of the annulus created by the eccentric casing. Loizzo and Sharma (Loizzo and Sharma, 2008) also reported long transition zones between tail cement and lead slurry in the Otway CRC-1 (Australia) CO_2 injection well. A small hole deviation, small washouts, and breakouts were the cause of the transition zones. Duguid et al. (Duguid et al., 2021) found that the installation of monitoring equipment outside of the casing can also affect cement placement and allow for migration pathways to form. Some CO_2 storage sites have also reported well construction issues unrelated to poor cement placement, like loss-of-circulation at the Ketzin Pilot Site (Germany) (Prevedel et al., 2009) and stuck pipe in a deviated well in the North Sea (Gregoire et al., 2009). However, neither the Ketzin nor the North Sea study reported a related well integrity problem.

3.3. Operational issues and associated methods for detection and remediation

Issues encountered during well operation can potentially impact well integrity. Respondents were asked about the impact of selected operational issues experienced prior to or during injection of CO_2 (Fig. 2b). The survey also asked respondents to describe their methodology for detecting and remediating the identified operational issues (Table 1).

No impact and not applicable were the most common responses for all the issues provided in the survey. Most operators who experienced negative impacts from operational issues categorized the impact as low. Only two respondents encountered issues that had a major negative impact on site operations: one response for exceeding caprock fracturing pressure and one for hydrate formation. Salt precipitation, thermal cycling, and scale formation were all identified as having no or low negative impact. Other issues described by survey respondents included monitoring instrument failure (major impact), leakage through degraded barrier elements and improperly installed well components (medium impact), and formation damage during injection testing (low impact). According to the respondent, the monitoring instrument failure resulted in replacement, retrieval and repair, or loss of monitoring data for the rest of the operation.

A review of the literature indicated that many of the operational issues listed in the survey result in problems that may not directly influence the integrity of the well. For example, precipitation of different solids like salt, scale, wax, or asphaltene can reduce injectivity. However, the relationship between reduced well performance and well integrity is not well studied. Other issues like exceeding caprock fracturing pressure and hydrate formation, which can cause significant operational and safety challenges, could conceivably lead to permanent well damage under specific circumstances.

GCS and CO_2-EOR operations are typically designed to inject CO_2 at downhole pressures lower than the reservoir and caprock fracturing pressures, to ensure integrity of the storage site (Bourne et al., 2014, Fu et al., 2017). In many jurisdictions, it is illegal to exceed the downhole

Table 1
Summary of survey responses to the detection and remediation aspects of the operational issues listed in the survey.

Well integrity issues	**Detection**	**Remediation**
Sustained casing pressure, gas migration, or surface casing vent flow	● Visually observed bubbling in cellar; pressure observations	● Annual testing is conducted to measure pressure and composition of leaked gas. Wells are not remediated if issue is minor and if flow is decreasing
Thermal cycling	● The problem was anticipated based on numerical simulation of the wellbore ● Decline in injectivity in the well that has the greatest fluctuation in injection rates and associated thermal cycling might be indicative of a problem due to thermal cycling	
Pressure cycling	● Intermittent CO_2 injection induces pressure cycling ● Drop in injection pressure due to reaction between carbonate rocks and acid gas	● Brine injection and a subsequent fall-off period
Injection of chemicals (other than water/ CO_2)	● N_2 and O_2 will be injected along with CO_2 ● Hydrocarbon gas was re-injected	
Scale formation	● Sliding sleeve monitoring containers ● Video indicated minor scale in injection tubing which is probably salt	● Acidification
Wax/asphaltene precipitation	● Anticipated ● Inferred from reduced flow rate ● Inferred from clogging of u-tube	● A processing skid with scrubber was installed to knock out wax prior to injection. ● Remediation using chemicals and/or physical cutting (wireline) ● Performing well clean outs prior to logging and managing production rates to avoid unfavorable temperature or pressure transitions within the wellbore
Salt precipitation	● Video of the wellbore	
Hydrate formation	● Anticipated ● Inferred based on reduced injectivity	● Drying prior to injection ● Heat/methanol flush ● CO_2 injection above a temperature of 10°C ● Insulation ● Thermal element
Exceeding caprock fracturing pressure	● Correlating bottom hole pressure values with leak off test results	● Installation of a drop pressure valve

fracture gradient and doing so may result in the early closure of a CO_2 injection operation. This is in agreement with the survey results in which exceeding caprock fracturing pressure was listed as a major impact issue (Fig. 2b). Operations at two CO_2 storage projects are known to have been affected due to concerns of approaching/exceeding caprock fracturing pressure (Kaufmann et al., 2021, Ringrose et al., 2013). Though no direct instances of well integrity issues were noted at these example sites, local loss of well integrity is possible if the pressure increases beyond the design specifications for the well.

Formation of gas hydrates was considered to be another major issue by the survey respondents. Gas hydrates are ice-like crystalline compounds that can form within minutes by the trapping of small gas molecules like methane, carbon dioxide and hydrogen sulfide, in cages created by hydrogen-bonded water molecules (Bavoh et al., 2019). They pose significant safety hazards like rapid pressurization of pipes or ejection of high speed projectiles that can result in loss of life (Sloan and Bloys, 2000). Hydrate formation can also result in operational difficulties like loss of injectivity. We found only one published report on problems associated with hydrate formation in the context of GCS/CO_2-EOR. Hydrate management measures have been incorporated in design and operation of CO_2 storage sites (IEAGHG, 2019, Roux and Andersen, 2010, Wildenborg et al., 2018).

Of the issues listed in the survey, observations of sustained casing pressure (SCP), surface/sustained casing vent flow (SCVF), and gas migration, are clear indications of well integrity problems. Reviewed literature indicated that SCP/SCVF occurrence is common in oil and gas wells (Bachu, 2017, Watson and Bachu, 2009, Wisen et al., 2020, Lackey et al., 2017, Lackey et al., 2021). Fewer studies have focused specifically on SCP/SCVF occurrence in the context of CO_2 storage (Sminchak et al., 2014). While studies have predominantly reported low instances of SCP/SCVF, it can become an issue if present to an excessive degree. Also, SCP/SCVF may be a greater concern for CO_2 wells because of potential reactions between fluids leaking along the wellbore and well materials like cement and casing.

Several other operational issues listed in the survey involved precipitation of solids like salt, scale, wax and asphaltene. This can result in pressure buildup, reduction in injectivity, reduction or stoppage in flow, formation damage, and/or damage to system components. Examples of GCS and CO_2-EOR sites that have experienced such issues include Snøhvit Field in the Barents Sea (Norway) (Hansen et al., 2013), CO_2-EOR site at Mumford Hills Field (USA) (Frailey et al., 2012), K12-B gas field (Netherlands) (Vandeweijer et al., 2011), Midale field (Canada) (Beliveau and Payne, 1991), CO_2 floods at the Little Creek field in Mississippi and in West Texas (USA) (Sarma, 2003). Several proactive and reactive measures have been developed to prevent and mitigate the issue of precipitation of solids. This includes avoiding operating conditions that facilitate precipitation, chemical pre-treatment of injected fluids to avoid precipitation, and physical, chemical and thermal methods of removing precipitated solids.

We were unable to find any field-based observations from a GCS or CO_2-EOR site that attributed loss of well integrity to thermal or pressure cycling, which aligns with the findings of the survey. However, several experimental and modeling studies have considered this possibility (Luo and Bryant, 2011, Aursand et al., 2017, , De Andrade et al., 2015, Roy et al., 2018, Goodwin and Crook, 1992, Jackson and Murphey, 1993). The context of many of these studies were potential future CCS solutions that may encounter large changes in pressure or temperature. For example, CO_2 injection in strongly depleted deep oil and gas fields, where Joule-Thomson cooling may occur upon CO_2 expansion into the reservoir (Oldenburg, 2007, Mathias et al., 2010), or direct injection of relatively cold CO_2 from ship-based transportation (Sarma, 2003, Oldenburg, 2007) into the warm formation. These potential CCS solutions are promising for exploiting offshore storage potential but have yet to be tested at larger scales.

3.4. Material Degradation

Of the topics covered in the survey, material degradation in CO_2 wells was the greatest concern as CO_2 reacts with most well materials and components. Survey respondents were asked about the acute degradation (sudden manifestation of degradation) and chronic degradation (slow developing degradation) of injection, monitoring, oil and gas (permanently abandoned, active or temporarily closed), and coal bed methane wells at their site. Specific degradation issues listed in the survey for each well type were cement degradation, casing corrosion, tubing or packer corrosion, and breakdown along well system component interfaces. We received 17 responses regarding acute material degradation and 16 regarding chronic material degradation. A total of seven respondents experienced some form of material degradation in the wells at their site and their responses are summarized in Table 2. The rest did not experience material degradation at their site. Three respondents experienced acute and up to four respondents experienced chronic material degradation in the injection and/or monitoring wells at their sites. Only one respondent experienced chronic material degradation in active/temporarily closed wells on their site. It should be noted that because these survey responses are based on operator experience at active CO_2 injection sites, they provide a narrower perspective on long-term integrity of wells that could impact CO_2 containment after injection operations are terminated and the site is closed.

3.4.1. Cement degradation

Most of the current research into well material degradation at CO_2 storage sites has focused on understanding the impacts of the unique chemical environment created by CO_2 storage on cement and steel. Most wells are constructed with ordinary Portland cement, which is inherently alkaline and thus reactive towards acidic CO_2-saturated brine. A large body of experimental and modelling work on the impact of CO_2 exposure on Portland cement is available in the scientific literature (Carroll et al., 2016, Ajayi and Gupta, 2019, Kiran et al., 2017, Zhang and Bachu, 2011). There is broad consensus on the type of chemical reactions that occur when Portland cement interacts with CO_2-saturated brines (Carroll et al., 2016, Ajayi and Gupta, 2019, Kiran et al., 2017, Zhang and Bachu, 2011). The rate of cement degradation depends on a variety of factors including the cement composition, the fluid composition, the velocity of the reacting fluid, and temperature (Carroll et al., 2016, Zhang and Bachu, 2011). The impact of the chemical reaction between CO_2 and cement on hydraulic and mechanical properties of the cement is less well understood. Laboratory studies on fractured and intact cores have observed both an increase and decrease in permeability due to reactions between CO_2 and cement (Carroll et al., 2016, Kiran et al., 2017), including cracking due to precipitation of calcium carbonate (Fabbri et al., 2009). Similarly, laboratory studies have confirmed a change in mechanical properties of cement upon exposure to CO_2. However, it is unclear if this change in mechanical properties can have an adverse impact on well integrity (Kiran et al., 2017, Wolterbeek et al., 2016).

Every survey respondent who answered questions about material degradation in wells at their site considered cement degradation to have a low impact/intensity (Table 2). These responses align with the field studies that have examined CO_2-exposed cements. Carey et al. (Carey et al., 2007) investigated wellbore samples collected from the SACROC Unit (USA), where CO_2-EOR operations have been ongoing for more than 30 years. Samples were recovered from 4 to 6 m above the reservoir-caprock interface. Up to 1 cm-thick precipitated carbonates were found along both the cement-casing and cement-shale interfaces. It was concluded that the cement matrix retained its ability to prevent significant migration of fluids. Crow et al. (Crow et al., 2010) studied a 30-year-old production well from a natural CO_2 production reservoir. Complete cement carbonation was observed in samples within the CO_2 reservoir, with the degree of carbonation decreasing with increase in distance from the reservoir. Compared to the cement cured in the laboratory, the carbonated cement cores had increased permeability and porosity and decreased mechanical strength. However, these altered properties were concluded to be adequate to resist CO_2 migration. Shen and Pye (Shen and Pye, 1989) studied wellhead cement samples retrieved from abandoned geothermal wells in the CO_2 flooded Brawley and Geysers fields (USA). Both carbonated and uncarbonated cement showed visible fracturing, which was attributed to thermal cycling effects. While the cement had sufficient compressive strength, its permeability was higher than desired. One of the cores retrieved from a 68-year-old well in the study by Duguid et al. (Duguid et al., 2014) did show partial carbonation of cement. The altered core had very low liquid permeability and mechanical properties indicative of competent

Table 2
Summary of survey responses on the impact of material degradation issues

			no	low	medium	major	not applicable
Acute degradation	Injection wells	Cement	0	3	0	0	0
		Well casing	0	2	1	0	0
		Well tubing and packer	0	2	1	0	0
		Breakdown along interfaces	0	2	0	0	1
	Monitoring wells	Cement	0	3	0	0	0
		Well casing	0	3	0	0	0
		Well tubing and packer	0	2	1	0	0
		Breakdown along interfaces	0	2	0	1	0
Chronic degradation	Injection wells	Cement	0	4	0	0	0
		Well casing	0	3	1	0	0
		Well tubing and packer	0	2	1	1	0
		Breakdown along interfaces	0	3	0	0	1
	Monitoring wells	Cement	0	1	0	0	0
		Well casing	0	1	1	0	0
		Well tubing and packer	0	1	1	0	0
		Breakdown along interfaces	0	1	0	1	0
	Active/ Temporarily closed wells	Cement	0	1	0	0	0
		Well casing	0	0	0	1	0
		Well tubing and packer	0	0	0	1	0
		Breakdown along interfaces	0	1	0	0	0

cement. These few field observations suggest that Portland cements react with CO_2, which results in a change in their hydraulic and mechanical properties. In the presence of competent original cement, these reactions do not seem to adversely affect the cement matrix's capability of preventing migration of CO_2.

With regards to choice of well cement, of the five total respondents who reported cement degradation in their wells, the wells at four respondents' sites were constructed with ordinary Portland cement and the wells at one respondent's site were constructed with CO_2-resistant cement. This is in agreement with the findings of Parker et al. (Parker et al., 2009). They reported that most approaches of limiting CO_2 attack on cement include substituting part of the Portland cement with fly ash, silica fume, or other non-reactive material. Non-Portland cements have not been widely used in CO_2-EOR due to their high cost and the observed adequate performance of conventional cement formulations. It should be noted that only a few respondents of our survey operated offshore sites. And it is still unclear if alternative cement formulations used in offshore environment also exhibit adequate barrier performance upon long term exposure to CO_2.

3.4.2. *Casing and tubing corrosion*

Acidic environments created by the dissolution of CO_2 in brine makes carbon steel, used in well components like casings, tubings, and packers, more susceptible to corrosion (Kiran et al., 2017, Choi et al., 2013). The redox reaction between iron and carbonic acid can consume significant amounts of metal in casing and tubings. In their review of corrosion of carbon steel in CO_2 storage environments, Choi et al. (Choi et al., 2013) found that the uniform corrosion rates of carbon steel can be as high as 20 mm/year, but the precipitation of iron carbonate on the steel pipe can reduce the corrosion rate to about 0.2 mm/year. Localized corrosion can be much more rapid in its penetration and can significantly reduce the lifetime of steel at locations with defects.

The impact of casing corrosion on site operations was considered by one survey response to be major. Three other responses considered it to have a medium impact and nine considered it to have a low impact (Table 2). Tubing and packer degradation was generally considered to have a higher impact on site operations. Two responses considered its impact/intensity to be major, followed by four medium and seven low. Casing-related corrosion problems are strongly affected by the ability of the adjacent cement to minimize contact of the casing by CO_2 and water, which may perhaps explain the differences in the corrosion-related issues reported in field studies at CO_2 storage sites. Some CO_2 storage sites had minor problems with corrosion, such as the ones highlighted by Crow et al. (Crow et al., 2010) and Shen and Pyer (Shen and Pye, 1989), where all casing samples retrieved were in good condition with either no or limited corrosion. Gawel et al. (Gawel et al., 2017) reported thin layers of rust on the surfaces of the stainless steel casing and steel production string retrieved from a Ketzin (Germany) CO_2 monitoring well, indicating that with time, steel tubulars of any grade can show some level of corrosion in a CO_2 environment.

Unlike the examples above, several projects have reported major corrosion issues (Gawel et al., 2017, Newton and McClay, 1977, Todorovic et al., 2014, Hassan et al., 2006, Laumb et al., 2016). Severe corrosion problems were detected in the CO_2-water injection wells during the first years of operation at the SACROC Unit (USA) (Newton and McClay, 1977). Plastic coated flow meters and valves experienced extensive corrosion at locations where the coating was damaged. Tubings from up to 25 % of the injection wells were pulled and inspected each year. On average 53 % were reclaimed for use as plastic-coated injection tubing, and 47 % were downgraded for other service. It was concluded that proper handling to prevent damage of the plastic-coated tubing was paramount in improving their corrosion performance. Laumb et al. (Laumb et al., 2016) reported that the lower section of the casing used as a water/CO_2 injector in the Weyburn CO_2-EOR field (Canada) was completely corroded, resulting in well abandonment. Corrosion issues resulted in tubing leaks in the Sheep Mountain CO_2-producing field (USA), forcing the replacement of tubing in 60% of the 29 wells (Nugent, 2005). These studies show that corrosion can be a major issue with CO_2 injection, especially if tubing/casing is in contact with formation fluids and CO_2 for long periods of time. This could be heightened at CO_2-EOR sites that use WAG (water alternating gas) schemes.

Regarding material of construction, steel was used to construct wells at three respondents' sites while corrosion-resistant steel was used in wells at two sites. Carbon steels are commonly used in construction of petroleum production assets. Due to their susceptibility to severe corrosion when exposed to CO_2-rich environments (Migahed et al., 2015), carbon steel is typically coated with plastic, epoxy, or glass reinforced epoxy to prevent corrosion in CO_2-EOR applications (Parker et al., 2009). Another approach to control corrosion is the use of chemical inhibitors, which decreases the corrosion rate of a material (Parker et al., 2009, Fu et al., 1996). Special grades of carbon steel or corrosion-resistant alloys are typically used when severe corrosion is expected (for example, deep wells, corrosive brine composition, or the presence of other chemicals like H_2S). Also, completion equipment like wellhead valve trims and wetted parts of packers are typically made of stainless steel, nickel or nickel alloys to provide resistance to prolonged CO_2 exposure (Parker et al., 2009).

3.4.3. Polymer degradation

Packer elements and seals also employ polymers that can be degraded due to exposure to CO_2. We were not able to find a large body of literature that discussed the role of CO_2 exposure in seal/packer degradation. Zhu et al. (Zhu et al., 2017) reported several instances of packer failures in the Shengli and Jilin CO_2-EOR fields (China). However, it is not clear if the packer failures in both fields were due to corrosion or polymer degradation. CO_2 is a good solvent for many common elastomers used in wells, which can result in their swelling upon exposure to CO_2 (Ansaloni et al., 2020, IEAGHG, 2010). Absorption of CO_2 by polymers can also change mechanical properties like stiffness and toughness (Zhu et al., 2017, Ansaloni et al., 2020). To mitigate against such degradation of polymer properties, Parker et al. (Parker et al., 2009) recommend the use of CO_2-resistant elastomers, polytetrafluoroethylene, and nylon for packer elements and seals. Swell-resistant materials like hardened and nitrile rubbers are used for downhole packers (Parker et al., 2009, IEAGHG, 2010, Meyer, 2007).

3.5. Well Repair and Remediation

Material degradation in wells may ultimately lead to well repair and remediation. Survey respondents were asked to identify well components (tubings, casings, liners, annular cement, plug cement, and elastomers) that were repaired or changed during remediation of wells at their site. Survey responses in Fig. 3 show that tubings were the most commonly repaired/replaced well component during site operation. In the "Other" category in Fig. 3, survey respondents noted the repair/replacement of packers and high expansion retrievable bridge plugs (HEX plugs). A third response in the "Other" category stated that a former gas production well repurposed as a monitoring well had to be abandoned, though no reason was provided.

Several studies have reviewed component failures in CO_2 injection wells. Bachu and Watson (Bachu and Watson, 2009) analysed failures in 31 CO_2 injection wells and 48 acid gas disposal wells in Alberta (Canada). Most failures caused by CO_2 injection were associated with the well tubing and/or packer. Tubing failures have also been observed in high-temperature/high-pressure wells exposed to CO_2 in Oklahoma (USA), where CO_2 exposure was found to have caused severe corrosion (Browning, 1984). Laumb et al. (Laumb et al., 2016) reported that several packers in the Weyburn field (Canada) needed to be replaced because of CO_2 exposure. These studies indicate that tubings and packers are the most frequently remediated/replaced components in the well system. The conclusions regarding the failure of tubings align with the survey results (Fig. 3). Since the survey question did not specifically list packers as a category, our survey was unable to capture the frequency of packer replacement/repair.

Other studies have also reported casing failures in CO_2 exposed wells (Laumb et al., 2016, Bachu and Watson, 2009, Liu et al., 2019). Bachu and Watson (Bachu and Watson, 2009) described a failure in which the casing split, resulting in short-term uncontrolled flow of CO_2 that continued until a new casing was installed to fix the problem. Laumb et al. (Laumb et al., 2016) reported that some sections in a water/CO_2 injection well at the Weyburn oil field experienced 70-80 % casing loss due to corrosion.

3.6. Well integrity and leakage monitoring methods

Site monitoring and containment verification is critical to the success of carbon storage projects (IPCC. 2005). While monitoring strategies are developed for an entire carbon storage site and serve multiple purposes, a prominent aspect of each plan is typically focused on detecting well leakage (Bourne et al., 2014, Gilmore et al., 2016). Comprehensive monitoring strategies typically require a variety of well integrity monitoring techniques, the applicability and cost of which can vary widely. Survey respondents were asked to describe the usefulness, cost effectiveness, and use-frequency of a variety of monitoring techniques used to detect leakage outside and inside wells.

3.6.1. Usefulness of leakage detection methods

Survey respondents were asked to describe the usefulness of pulsed neutron logging, soil gas flux sampling, different measurements from groundwater wells, and different surface geophysical measurements, in detecting leakage outside wells. For each technique, the respondent was asked to choose if the method was a) not useful, b) useful, or c) a critical monitoring method (Fig. 4a). In total, 16 responses were received. Respondents identified active seismic as the most useful. The other surface geophysical techniques listed in the question were identified as least useful. Some respondents also listed "Other" methods that included eddy flux towers, intelligent distributed acoustic sensing, and pressure/temperature monitoring in the injection and overlying permeable zones. Two techniques not listed in the survey or mentioned by survey respondents were satellite-based monitoring of ground surface deformation, which has been proven to be effective for monitoring GCS operations (Vasco et al., 2010), and tracer injections, which are useful for identifying the origin of a leak in the subsurface (Underschultz et al., 2011).

Recent research on the effectiveness of monitoring methods at carbon storage sites has focused on the ability of various techniques to detect leakage outside the wellbore (Yang et al., 2019, Buscheck et al., 2019, Bie et al., 2019). Bie et al. (Bie et al., 2019) reported that for most

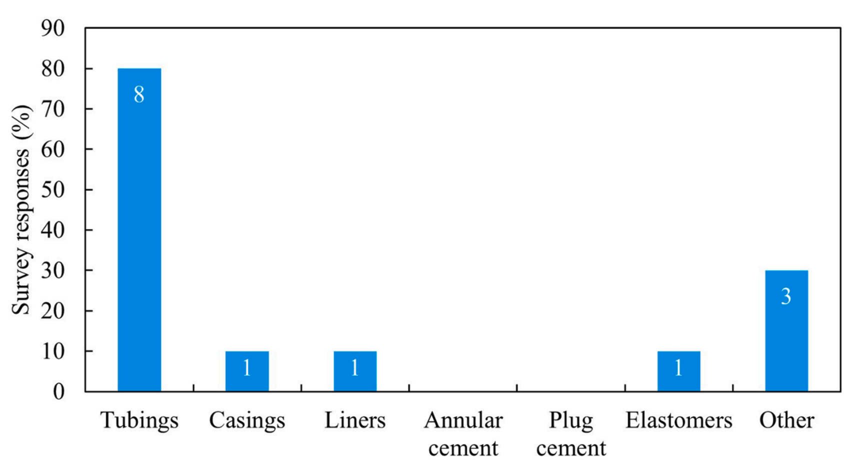

Fig. 3. Survey responses indicating the downhole well components that required repair or replacement during remediation and/or recompletion of wells. The percentages sum to greater than 100 % because the percentages were normalized to the total number of responses (10), but some respondents reported replacing/repairing more than one component.

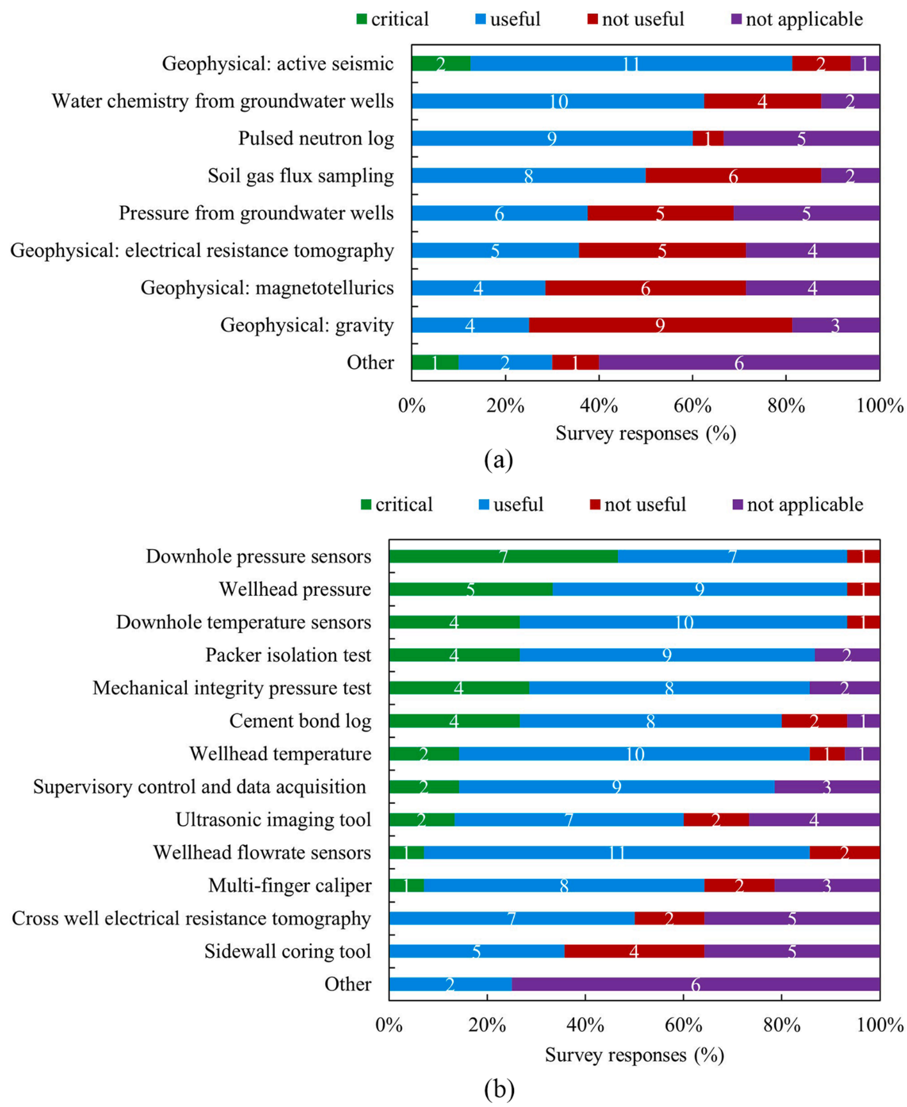

Fig. 4. Survey responses indicating the utility of monitoring methods at a GCS or CO_2-EOR site to detect leakage (a) outside the well and (b) within the well. Monitoring methods are listed sequentially based on the number of respondents that identified the method as a critical, followed by useful, and finally by the number of respondents (in increasing order) that identified the method as not useful.

leakage scenarios pressure monitoring for leak detection in an aquifer situated directly above the primary sealing caprock at the Cranfield site (USA) successfully detected leakage over a shorter timeframe compared to geochemical monitoring. Yang et al. (Yang et al., 2019) and Buscheck et al. (Buscheck et al., 2019) compared the effectiveness of near-surface geophysical techniques with that of downhole monitoring techniques. They found that surface geophysical methods were more effective at detecting shallow leakage plumes at the proposed Kimberlina CO_2 storage site (USA). Downhole monitoring methods outperformed surface geophysical methods for deep plume detection with the ability of leakage detection controlled by the number of wells, well location, and number of sampling points per well. While surface geophysical methods may have limitations with regards to detecting leakage at increased depths, they present monitoring options in cases where deploying well-based technologies may be challenging.

Techniques listed in the survey to detect leakage inside wells were pressure, temperature, and flow monitoring at either the wellhead or downhole, mechanical integrity and packer isolation testing, ultrasonic imaging, sidewall coring, cement bond logging, multi-finger caliper tool logging, implementation of a supervisory control and data acquisition (SCADA) system, and cross-well electrical resistance tomography. A total of 15 responses were received. All the monitoring techniques except sidewall coring were identified as critical or useful by 50 % or more of the respondents (Fig. 4b). Some respondents listed “Other” methods, which included a spinner flowmeter, corrosion logs, optical borehole televiewer, and downhole cameras. One technology commonly used to monitor for internal well leakage that was not listed in the survey or mentioned by survey respondents was downhole passive acoustic monitoring (e.g., noise logs) (McKinley et al., 1973).

Techniques for assessing well integrity and detecting leakage within wellbores have been the focus of a large number of studies (Nakajima et al., 2013, Zhang et al., 2018, Contraires et al., 2009). However, we could not find a study that compared the relative effectiveness of these monitoring techniques. Recently Jenkins (Jenkins, 2020) published a thorough review of the monitoring and verification plans of the FutureGen (USA), Quest (Canada), Goldeneye (Scotland), Tomakomai (Japan), and Archer Daniels Midland (USA) projects. Monitoring strategies were tailored to each site, and they varied for technical, regulatory, and social/political reasons. Despite the varying contexts, common elements between the considered monitoring plans for leakage detection included monitoring wells installed in shallow aquifers or above zone monitoring intervals that continuously measured pressure, temperature, and conductivity, episodic sampling and geochemical analysis of groundwater, air monitoring, pulsed neutron logging, and active seismic. Internal well leakage was monitored using downhole pressure and temperature sensors, routine mechanical integrity testing, and wellhead gas sampling. These observations are broadly consistent with the survey results in Fig. 4.

Jenkins (Jenkins, 2020) also reviewed monitoring strategies for CO_2-EOR operations at the Occidental Petroleum's Denver Unit and Hobbs Field operations in the Permian Basin (USA), Core Energy's operations at Niagara pinnacle reefs in Michigan (USA), and Exxon Mobil's acid gas (CO_2 and H_2S) injections at Shute Creek in Wyoming (USA). The monitoring plans for the CO_2-EOR operations were not as robust as the plans for the GCS operations considered, which was expected given the differences in regulatory requirements for the operations. CO_2-EOR operators typically relied on standard leakage monitoring techniques including monitoring the integrity of the well and surface equipment and relying on production data to provide insight into reservoir leakage. Zaluski et al. (Zaluski et al., 2016) also reviewed leakage monitoring techniques for their potential use at the CO_2-EOR operation in the Weyburn-Midale Field (Canada). They found that pulsed neutron logging and 3D seismic were the most effective plume tracking technologies to ensure that fluids were not escaping the storage reservoir, in line with the survey results in Fig. 4. They also found that soil gas and shallow groundwater quality monitoring were necessary to verify that CO_2 or brine leakage had not occurred.

3.6.2. Cost effectiveness of monitoring methods

Survey respondents were asked to describe the cost effectiveness of all the well integrity monitoring methods discussed above. For each technique listed, the respondent chose if the method was cost effective or too expensive. Sixteen responses were received. Two-thirds of the monitoring techniques were considered cost effective by 50 % or more of the respondents (Fig. 5). "Not applicable" was the most commonly received response for sidewall coring tool, cross-well electrical resistance tomography and all the surface geophysical monitoring techniques except active seismic. Active seismic, which was considered the most useful well monitoring technique to detect leakage outside the well, was also listed as the most expensive technique.

Cost-benefit analyses of the monitoring strategies considered at Shell's Quest (Canada) and Goldeneye (Scotland) carbon storage projects provide insight into the relative costs of monitoring techniques (Bourne et al., 2014, Dean and Tucker, 2017). The methods identified as being the most expensive were seismic, groundwater monitoring for artificial or natural isotope tracers, magnetotellurics, and distributed temperature and pressure sensing. Moderately expensive techniques were distributed acoustic sensing, mechanical integrity testing, groundwater monitoring for conductivity, pH, and gas composition, pressure fall-off testing, and groundwater pressure and temperature sensing. Less expensive techniques were wellhead pressure and temperature monitoring, cement bond and sonic logging, soil gas composition and flux monitoring, water chemistry monitoring, and running of a multi-finger caliper tool. While these observations broadly align with the survey results in Fig. 5, a few discrepancies regarding the cost of techniques like using a multi-finger caliper tool and soil gas monitoring

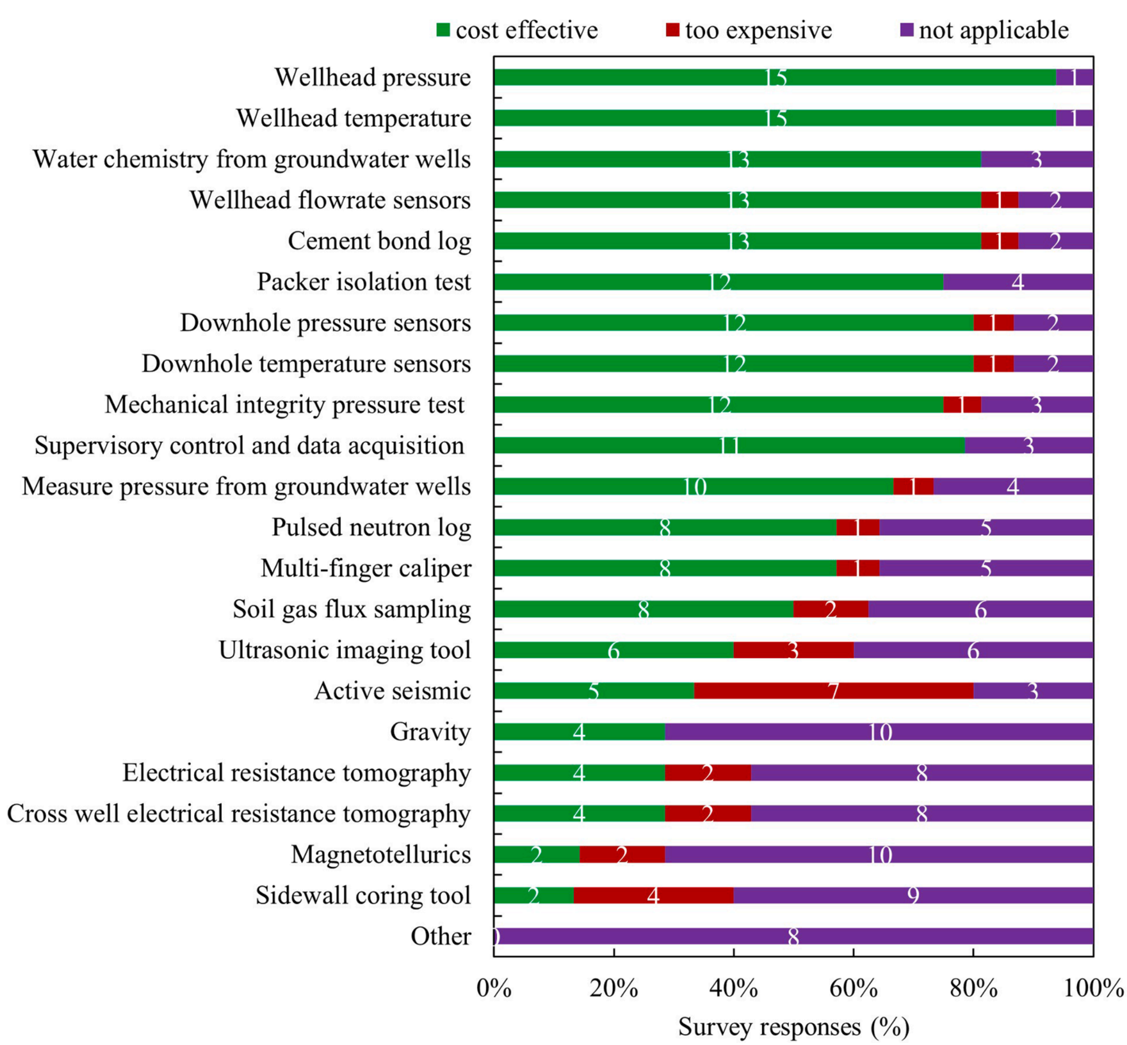

Fig. 5. Survey responses indicating the cost effectiveness of monitoring methods to detect leakage at a GCS or CO_2-EOR site.

are present.

Zaluski et al. (Zaluski et al., 2016) detailed the costs of implementing different leakage monitoring techniques for the CO_2-EOR operation in the Weyburn-Midale Field (Canada). They found that seismic monitoring techniques were the most expensive followed by downhole pressure and temperature sensing, formation fluid sampling, and groundwater sampling. With the exception of packer isolation testing and *in situ* stress testing, techniques widely used in the oil and gas industry to detect well leakage, including mechanical integrity testing, multi-finger caliper, pulsed neutron, and cement bond logging, were generally less expensive. Other methods with low lifetime costs were operating a monitoring and data management system and investigating the integrity history of nearby wells.

In general, the cost assessment of leakage monitoring techniques at the Weyburn-Midale CO_2-EOR site aligned with those for the Quest and Goldeneye carbon storage projects. All three found that the cost of deploying monitoring technologies in existing wells is cheaper than surface geophysical techniques. However, the estimates presented in these studies did not appear to include the cost of a new well, which is not required for surface geophysical techniques. One major difference between the studies was the cost estimate of groundwater and soil gas monitoring at the Weyburn-Midale project and the Quest and Goldeneye projects. Such differences between projects are expected because of the need to tailor monitoring plans to the unique aspects of each site. This may also explain some of the discrepancies between these observations and the survey results in Fig. 5.

3.6.3. Monitoring frequency

Survey respondents were asked to describe the monitoring frequency of different types of wells and the factors that affect monitoring frequency. We received 15 responses to these questions. Several of the survey respondents reported monitoring their site at frequencies higher than the three options of a) annually, b) bi-annually, and c) weekly, provided in the survey and these responses have been captured in Fig. 6. The frequency of monitoring strongly depends on the type of monitoring technology with some methods amenable to continuous monitoring while others are performed once every couple of years. This relationship between monitoring frequency and monitoring technique was not adequately captured by the survey question. "Other" responses to this question included evaluation of tubing and casing integrity every 5-10 years, mechanical integrity testing every year or 3-5 years, cement bond logging, ultrasonic imaging, and borehole televiewer several times during the post-injection phase. "Not applicable" was the most common answer for wells that were not injection or monitoring wells. This response may correspond to either those wells not being monitored or the respondent not being aware of their monitoring frequency.

Survey respondents were asked to identify factors that determined the frequency of monitoring at their site (Fig. 7). Responses indicated that most operators' monitoring frequencies were set by government regulation or company best practices. The respondents listed "Other" factors that influenced the monitoring frequency of the site, including the site surveillance plan, data collection instrumentation, and significant events like a large earthquake or changes of project framework.

Well leakage monitoring frequency has not been a major focus for research. The only monitoring schedule for a GCS or CO_2-EOR project we could identify in the literature was provided by Zaluski et al. (Zaluski et al., 2016). Some of the monitoring methods are designed to provide continuous information, for example pressure and temperature sensing. Periodic groundwater quality and soil gas sampling were scheduled to occur three times a year in the early stages of the project and be reduced to one time per year during the late stage of the project. Geophysical techniques like 3D seismic were planned to occur every other year during the project. Well-focused leakage monitoring techniques were not to be applied on a yearly basis; instead, a subset of wells was selected each year for testing. The schedule for the monitoring techniques described in Zaluski et al. (Zaluski et al., 2016) was based on the minimum frequency of use needed for each technique to provide useful monitoring information and was tailored to the Weyburn-Midale CO_2-EOR project. It is expected that regulatory requirements and unique features of a site or planned CO_2 injection operation will dictate a specifically tailored monitoring schedule.

3.7. Well integrity risk assessment

While injection and monitoring wells at GCS and CO_2-EOR sites are typically constructed to high standards to meet permitting requirements, legacy oil and gas wells in the vicinity of a project are often not constructed or abandoned with the future use of the reservoir in mind. Consequently, these wells may be more susceptible to integrity issues during GCS and CO_2-EOR operations. Well leakage probabilities are related to the long-term integrity of the legacy well and may be impacted by chemical or mechanical changes in the reservoir from CO_2 injection (Carroll et al., 2016, Kiran et al., 2017, Zhang and Bachu, 2011). When considering only the quantity of CO_2 leaked, leakage consequences are a function of the site characteristics and the effective well permeability, depth with respect to the storage interval, and location in relation to the CO_2 plume (Lackey et al., 2019, Siirila-Woodburn et al., 2017, Zulqarnain et al., 2019, Zulqarnain et al., 2017, Duguid et al., 2019). To understand the risk assessment process followed by operators, survey respondents were asked about the availability of information on legacy wells, their approach for assessing the risks associated with legacy wells, and the course of action taken if well integrity risks were deemed unacceptable.

3.7.1. Availability of information describing integrity status of plugged and abandoned wells

Databases of well information are typically maintained by regulatory agencies. However, the quality and availability of these data vary widely making the available information highly heterogeneous and of variable quality (Lackey et al., 2021). Survey respondents were asked to describe the availability of information and the standards that were followed to plug and abandon wells in the vicinity of their project. Of the 17

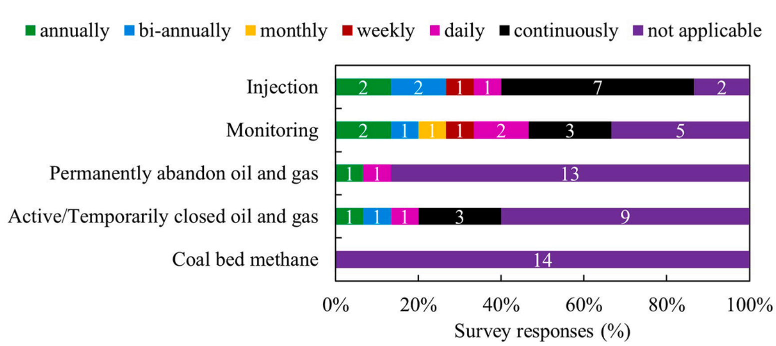

Fig. 6. Survey responses indicating the frequency of monitoring for every well type at a GCS or CO_2-EOR site.

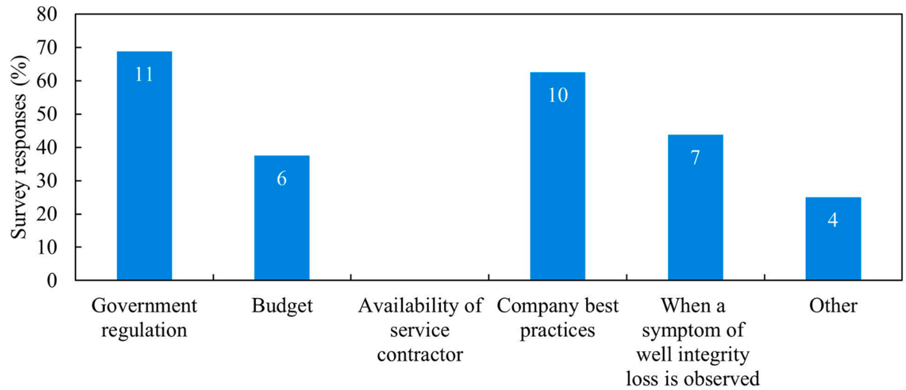

Fig. 7. Survey responses indicating the important factors that control monitoring frequency at a GCS or CO_2-EOR site.

respondents, nine (53 %) were aware of the materials and methods used to plug wells at their site and only one (6 %) noted that plugged wells were present at their site for which no information was available. The other seven respondents rated this question as “Not applicable”.

When asked about the integrity status of plugged wells, three (17 %) respondents reported having plugged wells with unknown integrity status. Two of these three respondents reported that fewer than five plugged wells with unknown integrity status were present at their site. The third respondent reported that their site had 51-100 plugged wells with unknown integrity status. Of the 17 total respondents, four (23.5 %) indicated that wells were plugged following API standards; one (6 %) indicated that wells were plugged following the NORSOK standard; and four (23.5 %) selected the Oother” category to indicate that wells were plugged using the relevant regulatory standard. The remaining eight responses (47 %) were “Not applicable”.

Large-scale spatial analyses of plugged and abandoned well locations with respect to prospective carbon sequestration sites have been performed in some regions. Gasda et al. (Gasda et al., 2004) analysed the spatial distribution of wells that penetrate a deeply seated aquifer ideal for carbon storage in the Alberta Basin (Canada). The region has been heavily developed for oil and gas extraction and the authors found that future carbon storage operations could impact as many as several hundred wells or as few as twenty depending on the chosen location. Nicot (Nicot, 2009) performed a similar analysis of wells in the Texas Gulf Coast (USA) and also found that the high density of drilling in the region increased the likelihood that future carbon storage operations in the Gulf may intersect abandoned wells.

A more detailed analysis of plugged and abandoned wells at the Cranfield CO_2 sequestration site in Mississippi (USA) was performed by Nicot et al. (Nicot et al., 2013). Seventeen plugged and abandoned wells were present in the Cranfield Project’s area of influence, 10 of which were retrofitted as producing wells. Regulatory records with information about the plug depths and materials used were available for all 17 wells. The authors analysed cement bond log data and found only one plugged well with “bad” quality cement that may result in significant CO_2 leakage.

Wells located in the area of influence of the proposed Kimberlina CO_2 sequestration project (USA) were characterized by Jordan and Wagoner (Jordan and Wagoner, 2017). They identified 1,345 wells that would be impacted by a pressure increase of 0.6 MPa from the hypothetical injection. Only 516 of the identified wells had depth information readily available, and 99 of these intercepted the targeted storage reservoir. Regulatory records were located for 96 of those 99 wells. One in ten wells lacked cement between the target zone and the base of the deepest underground source of drinking water, as these wells were drilled prior to 1960 before the establishment of modern regulatory standards.

The reviews of plugged and abandoned wells at the Cranfield and Kimberlina sites (USA) capture the degree to which the quality and availability of oil and gas regulatory records vary between jurisdictions. While plugging and construction records were available for all plugged and abandoned wells at the Cranfield site, they were only available for a fraction at the Kimberlina site. This variability in data availability was also present in the survey responses, where missing information impacted one of the ten sites with abandoned wells nearby. Three operators also reported having plugged wells with an unknown integrity status.

The Cranfield and Kimberlina projects also illustrate how the challenge of evaluating plugged and abandoned wells increases with the number of wells located in the area of influence. Researchers were able to thoroughly review the available information for all 17 wells at the Cranfield site. This level of analysis was not possible for the 1,345 wells near the Kimberlina site. Well integrity evaluation may be particularly challenging for CO_2-EOR sites, which inherently operate in active oil and gas fields. The three survey respondents that reported having plugged wells with an unknown integrity status nearby were CO_2-EOR operators, one of whom indicated that 51-100 plugged wells were in the vicinity of the project. Similar legacy well problems are expected for future CCS projects involving re-use of depleted oil and gas reservoirs for long-term CO_2 storage purposes.

3.7.2. Well integrity risk assessment

Operators of CO_2-EOR and GCS sites must gather relevant information and characterize the risks posed by legacy wells in the vicinity of their project. To better understand the well integrity risk evaluation process, survey respondents were asked to rank their perceived importance of 20 factors when evaluating well integrity. These factors were grouped into six categories: 1) general well attributes (well design, age, and depth), 2) well type (storage, disposal, gas, or oil), 3) well status (abandoned, inactive/suspended, or active), 4) well orientation (vertical or deviated), 5) cement coverage (over fraction of target reservoir, over caprock fraction, through entire caprock, or through caprock to surface) and 6) availability of relevant data (well logs, mechanical integrity test information, and well construction diagram). Cement coverage in the annulus was identified as the most critical risk factor as all four options related to cement coverage were in the top ten of the well integrity risk factors considered (Fig. 8). Well depth and orientation were considered to be the least important factors in evaluating well integrity.

Survey respondents were also asked about the information they would ideally wish to have to make the best possible assessment of well integrity risks associated with legacy wells at their site. All ten responses to this question mentioned some form of historical data about the usage, construction, or integrity of the well. Cementing practices were a major focus; six respondents listed cement bond logs or some other form of information about the quality of the cement job as valuable information.

Research efforts to identify relationships between well integrity loss and well construction/operation have primarily relied on large regulatory databases that contain operator-reported integrity testing information for thousands of oil and gas wells (Bachu, 2017, Watson and

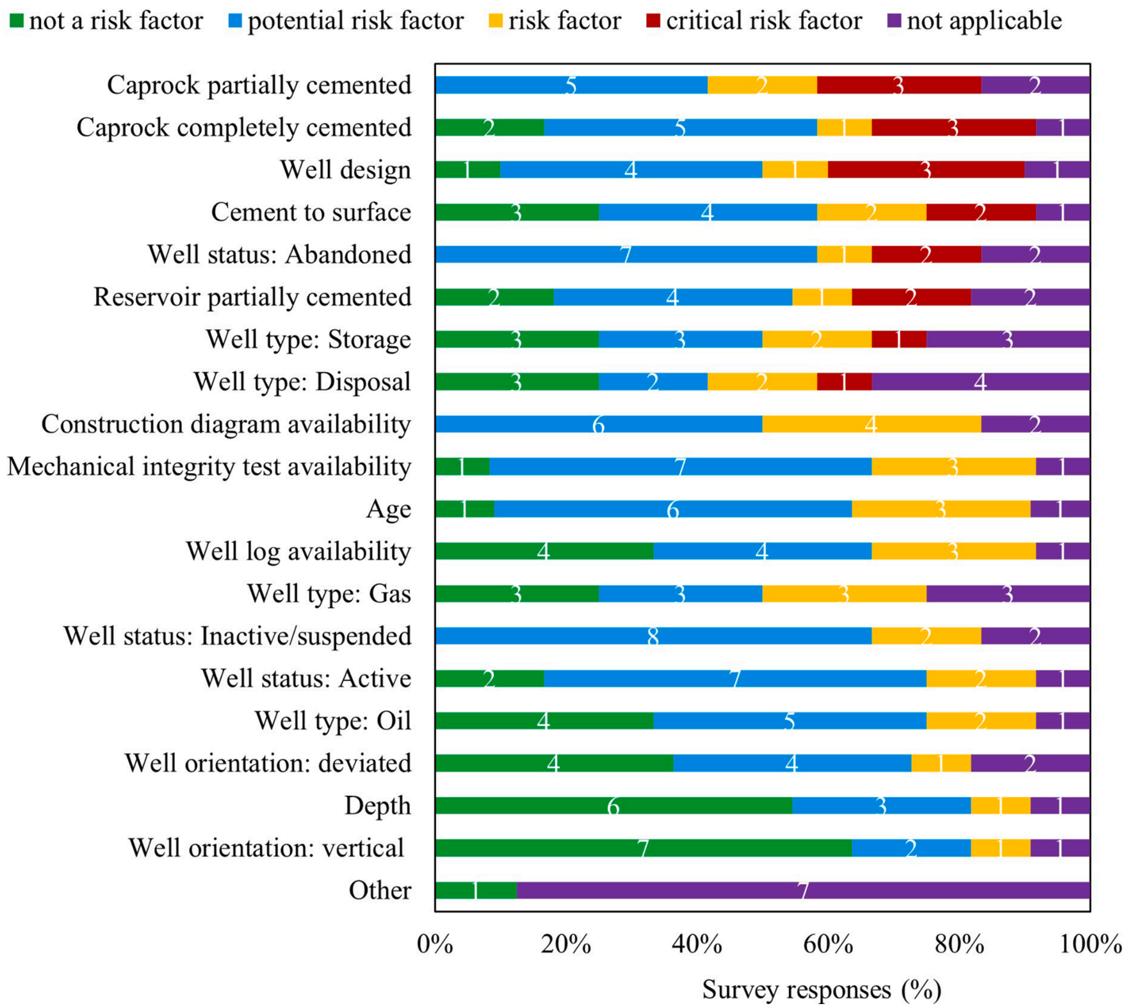

Fig. 8. Survey responses indicating the degree to which site operators considered potential well integrity risk factors in their evaluation of legacy wells at their site.

Bachu, 2009, Wisen et al., 2020, Lackey et al., 2017, Lackey et al., 2021, Davies, 2011, Ingraffea et al., 2014, Montague et al., 2018). Watson and Bachu (Watson and Bachu, 2009), Bachu (Bachu, 2017), and Montague et al. (Montague et al., 2018) analyzed the largest such database maintained by the Alberta Energy Regulator (Canada). Wellbore deviation, cement location, cement quality, well type, and abandonment method were found to be correlated with well barrier failure. Montague et al. (Montague et al., 2018) identified well installation year and wellbore deviation as the two most important factors associated with well integrity loss in Alberta. No correlation was observed between barrier failure and well age, operational mode, completion/perforation interval, or presence of H_2S (Watson and Bachu, 2009) Lackey et al. (Lackey et al., 2021) and Ingraffea et al. (Ingraffea et al., 2014) also observed a correlation between wellbore deviation and barrier failure and found no relationship between well age and barrier failure in their analyses of wells in Colorado, New Mexico, and Pennsylvania. Wisen et al. (Wisen et al., 2020) also did not observe a relationship between well age and barrier failure for wells in British Columbia, but suggested that a lack of testing over the lifetime of older wells may have resulted in the underreporting of integrity issues among these wells. This observation is also applicable to wells in Alberta, Colorado, New Mexico, and Pennsylvania where well integrity testing has predominantly taken place after the year 2000. Unlike Watson and Bachu (Watson and Bachu, 2009), Lackey et al. (Lackey et al., 2017) found no relationship between cement location and integrity loss.

Recent efforts have been made to assess leakage risk by field testing oil and gas wells that have been exposed to CO_2 in the subsurface (Sminchak et al., 2014, Sminchak and Moody, 2018). Sminchak and Moody (Sminchak and Moody, 2018) reviewed 1,500 oil and gas wells in Michigan and Ohio and tested 53 for signs of a barrier failure, but found no major issues. The authors concluded that the multiple strings of casing, cementing over casing crossovers, and the installation of wells with excess cement likely prevented integrity issues among the wells considered. King and Valencia (King and Valencia, 2014) reviewed a number of plugged and abandoned well leakage case studies and concluded that older wells had a higher leakage potential than newer wells, and that geology, adherence to best practices, and the regulatory environment could impact the performance of a well plugging and abandonment operation. Duguid et al. (Duguid et al., 2019) relied on expert elicitation and identified well age, depth, type, deviation, history of leakage, history of casing failure, suspension status, cement top, cement quality, casing quality, plug regulatory era, location within the CO_2 plume, and formation in which the production casing was set as the 13 factors to identify wells with an increased potential for well leakage at the Weyburn-Midale CO_2-EOR project.

While an understanding of the general well attributes is critical for evaluating its leakage risk, subsurface conditions are also important and can significantly influence leakage rates along wells (Pawar et al., 2016). Thus, the location of the well with respect to the CO_2 plume and the degree to which reservoir pressure increases at the well bottom are important considerations during well leakage risk assessment. Chemical reactions between CO_2 and well materials like cement or casing can alter the leakage pathway and impact well leakage rates (Carroll et al., 2016). Therefore, evaluating well materials in the context of the projected geochemical environment of the injection reservoir may also be a valuable consideration during well leakage risk assessment. Many recent studies of well leakage have focused on projecting leakage risks at GCS sites over their lifetime (Viswanathan et al., 2008, Siirila-Woodburn et al., 2017, Zulqarnain et al., 2019, Pawar et al., 2016, Stauffer et al., 2009, Loizzo et al., 2011). Lackey et al. (Lackey et al., 2019) and Zulquarnain et al. (Zulqarnain et al., 2019) recently demonstrated workflows for using GCS system models to characterize field-scale well leakage risks that could be tailored to a specific site. Loizzo et al. (Loizzo et al., 2011) and Siirila-Woodburn et al. (Siirila-Woodburn et al., 2017) proposed less computationally intensive approaches for estimating well leakage risks. All of these methods take site-specific characteristics into account and provide insight into the risks associated with legacy wells. Mention of such factors were missing from the survey respondents' answers on well integrity risk assessment.

3.7.3. Well integrity risk management and mitigation strategies

After well integrity risks are characterized and understood, operators must manage those risks and mitigate them if they are unacceptably high. Survey respondents were asked to describe the course of action taken at their site to manage legacy wells that were determined to have an unacceptable level of risk. Six respondents replied, four of which identified plugging, abandonment, remediation, testing, or re plugging of high-risk legacy wells as their preferred method. Avoidance of high-risk legacy wells was also listed by a survey respondent.

Survey responses regarding risk mitigation strategies primarily focused on traditional methods for preventing leakage along wells that are widely used in the oil and gas industry. Multiple respondents outlined a process that generally involved: 1) detecting leakage using well logging or other testing techniques, 2) re-entering the well to repair it, and 3) well plugging or re-plugging if necessary. Manceau et al. (Manceau et al., 2014) reviewed studies about remediation techniques for well barrier failures. The well intervention topics addressed were wellhead repair, packer replacement, tubing repair, casing patching, swaging, well killing, well plugging and abandonment, and surface blowout management. Castaneda-Herrera et al. (Castaneda-Herrera et al., 2018) focused on techniques for repairing faulty cement and reviewed studies that have tested the efficacy of traditional Portland cement, and other nontraditional fluids.

Researchers have also explored methods for preventing well leakage that are not centered on well interventions (Manceau et al., 2014) These methods generally involve some form of fluid management to counteract the forces driving CO_2 leakage and can be grouped into passive and active techniques. Two passive fluid management techniques include avoidance of potential leakage pathways and stopping or delaying injection. Avoidance involves the identification of potential leakage pathways prior to injection and the design of a CO_2 injection plan that avoids those pathways. Stopping or delaying injection is done to prevent further increases in reservoir pressure in an attempt to reduce the pressure gradient driving CO_2 leakage. Survey respondents noted both of these passive fluid management techniques in their responses.

The active fluid management techniques reviewed in Manceau et al. (Manceau et al., 2014) were brine/CO_2 extraction and the formation of a subsurface hydraulic barrier. The goal of brine/CO_2 extraction is to reduce reservoir pressures to decrease the pressure gradient driving leakage. Hydraulic barrier formation involves the injection of brine into a non-potable aquifer overlying the injection reservoir to create a zone of increased pressure above the CO_2 plume. This is done to offset the pressure increase and buoyancy of the CO_2 plume in the target reservoir. CO_2 can be immobilized in the subsurface through enhanced dissolution and residual trapping by flowing brine over the CO_2 plume. Other remediation techniques not reviewed in Manceau et al. (Manceau et al., 2014) include use of oxygen scavengers to prevent corrosion (Loizzo et al., 2011), and injection of chemicals that react with CO_2 to precipitate calcite and clog leakage pathways (Wasch and Koenen, 2019).

4. Discussion and Research Recommendations

The 22 survey responses formed a representative sample of GCS and CO2-EOR operations spanning both small- and large-scale operations. Based on the alignment between the survey responses and the current state of research and development we have identified certain areas that can benefit from further investigation.

4.1. Material degradation

Of the topics covered in the survey, material degradation in CO_2 wells was the greatest concern as CO_2 reacts with most well materials and components. Both the survey responses and the literature indicate that corrosion is a severe problem at sites with CO_2. Understanding of corrosion and pitting rates of carbon steel in the context of CO_2 storage remains an active area of research. Rubber/seal degradation has also been reported in sites with CO_2, but this topic has not yet been extensively researched. Reactions between CO_2-saturated brine and conventional Portland cement are well understood but their impact on the hydraulic and mechanical properties is less clear. Field studies suggest that in the presence of competent original cement, reactions with CO_2 do not adversely affect the cement's capability of preventing migration of CO_2. This result is in line with the survey responses that categorized cement degradation as a low-impact issue.

Material degradation can eventually require repair or replacement of failed components. Tubing and packers were the most commonly replaced well components.

4.1.1. Research recommendations

- Analyze literature on uniform corrosion rates of steel in the context of subsurface conditions expected in CO_2 storage sites.
- Explore mechanisms and rates of localized/pitting corrosion of steel upon exposure to CO_2.
- Characterize the mechanisms and time scales of degradation for traditional elastomers, and identify cost-effective alternatives.
- Quantify the long-term impact of CO_2-cement reactions on the mechanical properties and barrier effectiveness of relevant cement formulations.
- Assess the effectiveness of different material degradation mitigation strategies for well materials (carbon steel and other alloys, elastomers, and cement) accounting for: (a) resistance to adverse impacts of degradation, (b) cost, and (c) conditions of exposure.

4.2. Well construction and operational challenges

Survey respondents and the reviewed literature indicated that proper cement installation was the biggest well construction concern that could potentially influence well integrity at their site. However, the relationship between different well construction issues and the resulting integrity of CO_2 wells has not been widely studied and is not well known.

Survey responses for operational issues indicated that most issues can be managed during normal site operations. Many of the negative outcomes of operational issues like reduced CO_2 injectivity were not directly related to well integrity. However, the relationship between reduced well performance and well integrity is inadequately studied. The only operational issue considered that was indicative of problems with well integrity was the observation of sustained casing pressure (SCP). Survey responses and literature review indicate that SCP is manageable under most circumstances but can cause large leakage events if not controlled. Remediating SCP can also be challenging. While SCP is well studied with respect to oil and gas operations, few studies have considered SCP occurrence among CO_2 wells where reactions between leaking CO_2 and well materials may exacerbate SCP.

4.2.1. Research recommendations

- Refine understanding of the impact of well construction practices on effectiveness of cement placement and well integrity.
- Develop tools to identify the cause of sustained casing pressure, locate leakage paths, and quantify the magnitude of potential fluid migration.
- Develop and test new remediation techniques to efficiently and effectively address problematic CO_2 leakage.
- Quantify the relationship between reduced well performance and well integrity.
- Define safe operating envelopes and recommended practices to avoid well integrity problems caused by thermal and pressure cycling.

4.3. Well integrity and leakage monitoring

There are a large number of well integrity and leakage monitoring techniques available to GCS and CO_2-EOR site operators. Survey respondents indicated that a vast majority of the monitoring techniques addressed in the survey were useful and cost effective. While no studies have compared the relative effectiveness of techniques to detect leakage, reviewed literature suggests that direct measurement of leaking fluids or leakage pathways inside the well system are typically straightforward to apply and interpret, widely used in the oil and gas industry, and cheaper to deploy in existing wells, making them more attractive compared to non-well based leak detection techniques. However, non-well based technologies like surface geophysical techniques present monitoring options in cases where deploying well-based technologies may be challenging. The negative perception of most surface geophysical monitoring techniques, except active seismic, is likely due to the poor spatial resolution of these methods at depth and the lack of widespread use in the oil and gas industry.

The use frequency of these monitoring techniques was found to be a function of technology, regulatory requirements and company best practices. However, a comprehensive understanding of the optimal use frequency of the various monitoring techniques is still lacking.

4.3.1. Research recommendations

- Continued refinement of low-cost active seismic monitoring technology (i.e., distributed acoustic sensing) with consideration of configurations targeting detection of fluid migration outside of wells.
- Apply value-of-information approaches to optimize the technologies used and their frequency of application for well leakage monitoring.
- Conduct field studies to test the effectiveness and resolution of various geophysical monitoring techniques and deployment configurations for detection of unwanted fluid migration.

4.4. Well Leakage risk assessment

Both survey responses and reviewed literature indicated that information describing the construction, integrity history, and plugging of abandoned wells varies significantly between jurisdictions. The challenge of evaluating the integrity of plugged and abandoned wells increases with the number of wells present at the site. Survey responses and reviewed literature indicated that cement practices and well design were important well attributes in assessing the leakage risks of legacy wells. Reviewed studies have also found that well orientation is important in well leakage risk assessment, which is in contrast with survey responses that considered well orientation to be the least important factor. Reservoir conditions was another consideration noticeably absent from survey responses regarding information important for risk assessment. A large number of studies focused on modeling leakage risks at GCS sites have illustrated the relationship between reservoir conditions and well leakage.

Techniques identified for mitigating unacceptable leakage risk at abandoned wells include direct and indirect management approaches. Survey results focused on direct well intervention techniques commonly used in the oil and gas industry, and also mentioned the passive/indirect method of stopping CO_2 injection. In addition to these, the reviewed literature identified active/indirect methods to address high leakage risk, including fluid (brine or CO_2) extraction and subsurface hydraulic barrier formation.

4.4.1. Research recommendations

- Improve the availability of existing well construction and inspection data through digitization of historical regulatory records.
- Establish quantitative relationships between well information in regulatory databases and indicators of leakage risks for use in prioritizing well inspection and remediation efforts.
- Develop and test methods to quantify leakage risk and uncertainty when well attribute data are missing.
- Evaluate different mitigation and risk management approaches when leakage risk of legacy wells is unacceptable.
- Incorporate improved characterizations of well barrier integrity, leak detectability, and mitigation into quantitative risk assessment and management frameworks for improved decision support.

5. Conclusions

The survey responses and accompanying literature review provided insight into the alignment between well integrity issues experienced by CO_2 injection operators in the field and the well integrity issues studied by the research community. This comparison between survey responses and literature review highlighted pressing research needs in the areas of material degradation, construction and operational challenges, integrity and leakage monitoring, and leakage risk assessment. Of the research needs identified, those related to material degradation were potentially the most important and currently the least understood. A quantitative understanding of cement, steel, and polymer degradation rates under relevant storage conditions, and their impact on the composite well system is still needed to understand and forecast the long-term (>100 years) integrity of wells exposed to CO_2. Another pressing need is the continued refinement and cost reduction of effective monitoring technologies. More work is also needed to understand the tradeoffs between in-well monitoring and the leakage risks that may be introduced by these technologies. A general lack of well integrity data and information was a theme that united all identified research areas. To better understand potential issues, improved access to data and information from regulators and/or operators is necessary. Comprehensive data about well construction, well attributes, well testing, and problems encountered in wells over their lifetime can progress our overall understanding of well integrity and potentially enable the development and validation of models to forecast well leakage risks.

In general, operator survey responses and literature review indicated that well integrity issues at GCS and CO_2-EOR sites are manageable through current industry best practices. This finding, while positive, may be influenced by the relatively low response rate to the survey (40%) and by the low frequency at which well integrity issues are reported to occur. This again highlights the scarcity of well integrity information and demonstrates how a lack of information can be an impediment to understanding the phenomenon. As the majority of responses were from operators working at active sites, survey results did not provide insight into the long-term (>100 years) integrity of wells. Similarly, responses provide limited information on industry best practices for plugging and abandonment to ensure long term well integrity. Taken together, these findings highlight that more data, and continued efforts to understand the current state of practice for well integrity management and align well integrity field experiences with research efforts are needed. The importance of these efforts will continue to grow alongside the urgency for large-scale field deployment of GCS.

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Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Supplementary materials

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