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Plug and abandonment of oil and gas wells – A comprehensive review of regulations, practices, and related impact of materials selection

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ABSTRACT

This paper reviews the state of research in permanent barrier materials for plug and abandonment of oil and gas wells to identify key strengths and weaknesses of each barrier material and understand the impact of reservoir conditions and fluids on barrier failures. The influence of regulatory requirements on P and A practices and the impact of selected barrier material on possible repurposing of depleted reservoirs for hydrogen and CO_2 storage are also discussed.

This review reveals that previous studies in these areas have focused primarily on improving plug placement and durability without significant consideration of the potential for long term development of leakage paths in the old wellbore infrastructure (cement and casing) whose surfaces remain exposed to reservoir fluids below the permanent plug after conventional P and A. The need for a new approach to plug and abandonment materials selection and reengineering of materials placement methods to ensure permanent isolation of reservoir fluids from existing well infrastructure is herein identified especially as the stock of wells nearing their end of life grows on a global scale.

A summary of studies in the accelerated degradation of Portland cement in the presence of corrosive reservoir fluid under high temperature and pressure conditions is also presented. This will significantly drive research in materials selection for alternative barrier as HPHT wells mature for permanent abandonment.

1. Introduction

From 1859 when rotary technology became the industry standard for drilling oil and gas wells, over 65,000 oil and gas fields have been discovered across the globe stretching from normally pressures to abnormally pressured wells in highly challenging environments. However, what happened to wells at the end of their productive life was not clearly defined by regulating authorities in the early days. As a result, operators considered plug and abandonment a capital intensive project with no returns and could afford to leave the wells as gasping holes on the ground or poorly abandoned at the end of their productive life (NPC North American Resource Development, 2011). Several of these wells have leaked and continue to leak hydrocarbons into the environment. (Vrålstad et al., 2019; Achang et al., 2020).

The drilling, completion and production processes lead to a disruption of the natural balance of underground rocks which must be restored in accordance with governing regulations at the end of the well's productive life or in the case of wildcat wells, the end of their useful life. This process is referred to as plugging and abandonment (P &A) of oil and gas wells.

Plug and abandonment of oil and gas wells has gained popularity in the past decade as multiple wells especially in the Gulf of Mexico and North Sea near the end of their economic productivity (Jordan, R. and Head, 1995), (Calvert and Smith, 1994; Barclay et al., 2001; Saasen et al., 2013; Rassenfoss, 2014; Davison et al., 2017; Vrålstad et al., 2019). In addition to the large number of mature wells that have aged naturally over decades, the current wave of plug and abandonments facing the oil and gas industry can also be attributed to the shorter production lifetimes of modern horizontal and some unconventional wells drilled in increasing numbers as the industry targets shale reserves and aims to optimise production.

According to (Oil & Gas UK, 2021) a total cumulative sum of £16.57 billion is forecast to be spent on decommissioning activities in the U.K section of the North by 2030. About 50 percent of this total is tied to plug

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and abandonment of wells. This indicates that further cost savings in decommissioning could be achieved through the development of alternative P & A materials and optimization of materials placement technologies. In addition to this, wells abandoned using Portland cement and bridge plugs have been reported to leak hydrocarbons into the environment (Vrålstad et al., 2019; Achang et al., 2020) which further necessitates the development and qualification of alternative plug and abandonment materials to achieve the regulatory go of establishing a long-term seal in every P & A operation.

Achieving permanent zonal isolation of reservoirs from the environment is very critical especially in offshore environments where the cost of remedial sealing operations and clean-up of hydrocarbon spills can run into millions of dollars (Liversidge et al., 2006). Therefore, every well needs to be properly abandoned with materials that will stand the test of time, reservoir conditions and maintain a permanent impermeable bond with the surrounding casing, cement or formation.

Significant progress has been made in P & A materials and materials placement technology over the years as discussed in section 3 below. These notwithstanding, the level of uncontrolled leakages reported from abandoned wells (Davies et al., 2014), necessitates further questions. Were these wells abandoned poorly, do industry practices encourage premature abandonment or is the industry process of material selection for well barrier elements based on a faulty system (Kaiser, 2017)? argues that there is no evidence of systemic problems with the way offshore wells are currently abandoned but there is not enough quantitative evidence to back this argument.

The following sections review regulatory requirements and improvements in well abandonment materials and technologies to point out the weakness of each material, their advantages and relevant case to shed light on potential areas of further research and drive greater adoption of alternative materials and materials placement technologies for permanent plugging and abandonment of oil and gas wells.

1.1. Plugging and abandonment landscape

The chart in Fig. 1 summarizes a 10-year forecast of possible well abandonment projects in the North Sea. In the UKCS, where the first exploration well was drilled in 1964, a total of 7385 development wells have been drilled at the end of 2021. In addition to these, a cumulative 2535 exploration and 1894 appraisal wells have been drilled in the same period (North Sea Transition Authority, 2022). On this section of the North Sea, a total of 1782 wells are expected to be decommissioned between 2021 and 2030. This accounts for 67% of the North Sea's wells decommissioning during the period. The remaining 33% of wells expected decommissioned in the North Sea within the period will be in Norway, the Netherlands and Denmark.

Well decommissioning in the UKCS is expected to proceed at an average of 150 wells per year from 2022 to 2024, a period expected to witness significant activity in the decommissioning of subsea wells in the UKCS. Up to 582 subsea wells, 54.81% of these which are in the Central North Sea of the UKCS (Oil & Gas UK, 2021) are expected to be decommissioned during this period. While subsea decommissioning is relatively more challenging, the cumulative experience of the industry from decommissioning of platform wells will contribute significantly to operational safety and cost efficiency of these projects.

Nearly 50% of approximately 29,000 mining and oil and gas wells drilled in Germany's North Basin are plugged and abandoned. Of this total, 80–90% of the hydrocarbon wells are decommissioned while about 3500 wells remained accessible (Bai et al., 2015).

In the British Columbia province of Canada, over 25000 wells have been drilled since the first known drilling activity in 1919. A study by (Trudel, E. et al., 2019) involving 24,421 wells; 14298 vertical wells, 7202 horizontal wells and 2921 deviated wells reveals that 30.3% of these wells have been abandoned, 40.5% were active, 21.2% were suspended and 8% were at initial stages of completion at the time. The average life cycle of production wells in the province at abandonment is estimated to be 17.3 years with vertical wells staying longer in production than deviated and horizontal wells. This decrease in productive time observed in horizontal wells is mainly a result of their higher contact area with the reservoirs that leads to a faster drainage of hydrocarbons. There are over 8200 wells in the province that are older than the average lifetime for the specific well types. Fig. 2 represents the yearly and cumulative number of suspended wells in British Columbia and points to a significant wave of abandonment activities in the British Columbia in the decades ahead. Given that most wells in this area are onshore and a small number of HPHT wells, details of lessons learnt from well abandonments in British Columbia might not be generally useful to the HPHT and offshore wells decommissioning campaigns of other

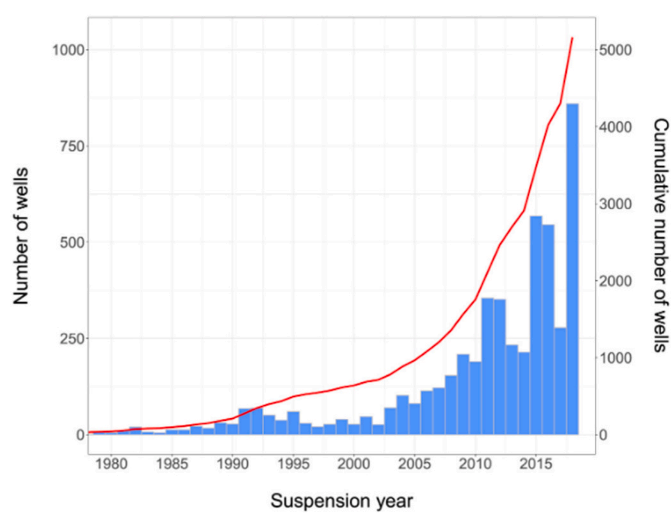
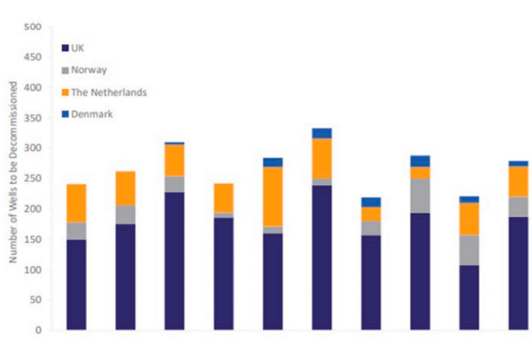


Fig. 2. Suspended wells in British Columbia based on suspension year and cumulative numbers (solid line) (Trudel et al., 2019).



Country	Number of wells	
UK	1,782	67%
The Netherlands	528	20%
Norway	278	10%
Denmark	91	3%
TOTAL	2,679	100%*

Fig. 1. A decade forecast of number of wells to be decommissioned in the North Sea (Oil & Gas UK, 2021).

regions. However, it will prove useful lesson for cost estimation and planning of well decommissioning in other onshore fields especially normally pressured fields.

A more recent study of plug and abandonment trends of gas well in Alberta by (Trudel et al., 2021) estimates a total of 468, 000 oil and gas wells drilled in the province; 164,876 are gas wells, 63.4% of which were active in 2021, 16.2% suspended and 19.4% abandoned. While the stock of suspended and aging wells continues to increase in Alberta, the region is still drilling actively and expected to reach 1775 gas wells per year in 2027 if current trends are sustained. Drilling of horizontal wells is on the rise in Alberta with 73% of 1205 gas wells drilled in the province in 2018 being horizontal.

The government of the province of Alberta has come up with two special programmes to encourage operators to decommission wells. The first encourages operators to work together to perform P&A and remediation work that could lead to 40% reductions in cost in common ownership areas according to pilot projects. The second, Site Rehabilitation Programme was initiated in 2020 as part of the Canadian Covid-19 Economic Response Plan with up to 1 billion dollars in funding. It aims to accelerate well abandonment and site reclamation efforts while creating jobs for Albertans (Trudel et al., 2021).

In the USA, plug and abandonment activities spread across the oil and gas producing states from the older wells of Pennsylvania drilled before any abandonment regulations to more recent offshore wells and shale gas wells drilled under well-defined state regulations. In Texas for instance, there were 18000 orphaned wells 2002, reduced to just around 8000 in 2009. Plug and abandonment in the state of Texas was progressing at around 1400 wells per year in 2011 (King and Valencia, 2014). A recent report from the Texas Railrooad Commission's website, shows a total of 43,118 orphaned wells from the inception of its well plugging programme in 1983 through February 2022 with an outstanding 8642 wells in the orphaned status. 160,000 oil wells and 87, 000 gas wells remain active in the state of Texas (Wei Wang, 2022). Fig. 3 shows the distribution of oil and gas well in the United States and their present status. Dry holes which are not relevant to the subject of this paper has been neglected., It is evident that a greater percentage, abbout 66%, of the wells in the USA remain candidates for plug and abandonment.

The US Gulf of Mexico is rated the largest P and A market in the world. This region has over 34400 drilled wells, 44% of which have been plugged and abandoned and about 19200 wells which are pending abandonment. 71% of these wells were drilled over 40 years ago. Southeast Asia including Thailand, Malaysia, Myanmar, Indonesia, and Philippines is rated the second largest market. Only 7% of 18900 drilled wells in the region have been plugged and abandoned (Aslani et al., 2022).

The industry is set for a wave of well decommissioning in the coming years, but it is important to note that these numbers of wells to be plugged and abandoned are only projections and subject to the impact of oil and gas economics, environmental factors, government policies and disease outbreaks, as seen in the last two years. Rising cost per barrel of oil could mean that operators have more money to spend on P & A projects but could also mean that certain wells considered uneconomic and hence decommissioning candidates in low oil price seasons become economically viable for extended production over a specific period. Additionally, these projections do not factor in the impact of manpower supply on decommissioning activities in the coming years. With an aging population of experienced professionals and a younger generation that is moving significantly away from oil and gas into data science and renewable energy careers, the oil and gas industry might be facing a skilled manpower supply crises if current trends are sustained.

1.2. A summary of well integrity and barrier failure issues

Davies et al. (2014) provides evidence that well integrity and barrier failure issues remain significant issues in the industry in both abandoned, suspended, and producing wells. The wells investigated by the authors are located in different regions of the world and differ significantly in age from those drilled in 1921 to some drilled as recent as 2013. The data suggest greater percentages of well integrity and barrier failure issues in older wells. However, these percentage values of observed well integrity issues cannot be used as a quantitative measure for comparison of integrity failure between older and recent wells. This is because the authors have not considered long term effect of well conditions on barrier failures and well integrity issues. Wells drilled between 2008 and 2013 and reported a less than 3.5 percent failure and integrity issues on the average. This should be considered a representation of current situation of these wells rather than an indication of what their long-term performance. Cement degradation and casing deterioration could lead to an increase in failures even in these recently drilled wells. Readers may refer to (Davies et al., 2014) for the full picture of the geographical locations and specific age of investigated

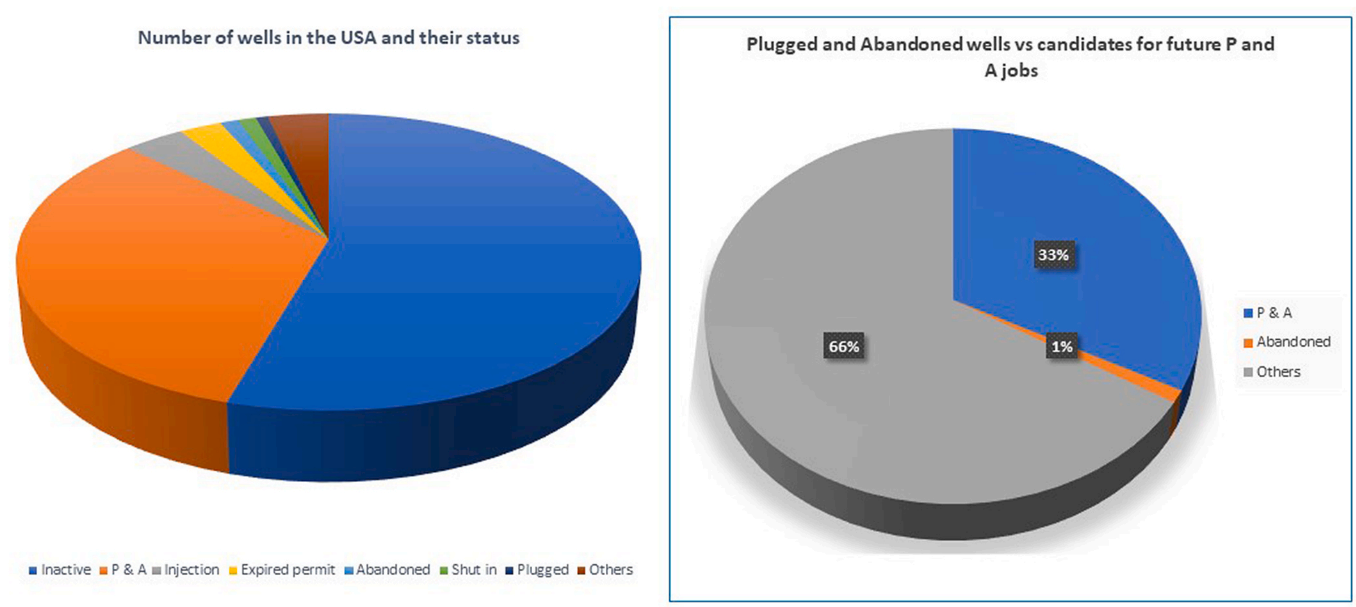


Fig. 3. Number of wells in the USA relevant for decommissioning. Adapted from (Achang et al., 2020).

wells.

A statistical study by (Dusseault et al., 2014) reveals that about 14% of Alberta's 430,000 oil and gas wells showed signs of surface casing vent flow.

It is also reported that about 25% of wells in the Gulf of Mexico have sustained casing pressure leading to about a 50 million dollar per year expenditure on remedial works to fix cement failures (Cavanagh et al., 2007). Elsewhere in the Netherlands (Schout et al., 2019), established that 1 out of 29 plugged wells is leaking some formation fluid into the environment. Other researchers such as (Kyle Ferrar, 2019; Watson and Bachu, 2009; Vielstädte et al., 2015; Chukwuemeka et al., 2017) have also identified additional leakages and studied the potentials for CO_2 and methane leakage from abandoned wells (Kaiser, 2017). went further to assess the frequency of remedial jobs and the use of rigless technologies for such operations in the United States' abandoned wells. In a study of the potential use of sidetracking for the recovery of un-swept reserves in abandoned fields (Chukwuemeka et al., 2017) identified the Bodo-West and Yula oil fields as some fields that have leaked hydrocarbon post abandonment in Nigeria.

Hydrocarbon leakage from abandoned wells could be a result of poor barrier placement or long-term deterioration of barrier materials. The deterioration of bridge plug elastomers in the presence of aggressive substances such as salt water, acidic gases and oxygen stripping inhibitors and the slight shrinkage of class G cement when it sets, makes the bridge plug/cement combination barrier a non-reliable permanent barrier element (Dusseault et al., 2000; CCEMC, 2015; Watson and Bachu, 2009).

The main pathways for potential leakage of reservoir fluids from abandoned wells are identified in Fig. 4 below using red arrows. A and B represent potential paths through the bulk cement behind casing and in the cement plug inside casing, C is the interface between cement and formation, D is external casing/cement interface and E is the internal cement/casing interface. Flow paths in A and B could be micro channels formed during cement hardening or fractures developed over the operational life of the cement arising from mechanical or thermal failure. Understanding these paths and the reasons for their existence is fundamental to defining the selection of plug and abandonment materials that achieve a permanent seal.

Apart from hydrocarbon leakage post abandonment, an additional concern for operators is potential CO_2 or H_2S leakage from abandoned wells. An analysis of 12,646 wells in British Columbia for instance showed the presence of at least 5% CO_2 in about 17.3% of the wells and the presence of H_2S in 37.5% of the wells. Such wells are subject to stricter regulations especially when they are located close to residential areas and contain 15% or more H_2S content (Trudel et al., 2019).

Studies like (Davies et al., 2014; Kang, 2014) have focused on the leakage of hydrocarbons into the environment from oil wells and neglected the possibilities of natural seepage of methane from shallow reservoirs located above developed commercial oil and gas reserves or sometimes in fields without any prior development activity. Natural seepage of hydrocarbons is well documented in literature (Kvenvolden and Rogers, 2005; Etiope, 2009) (Hornafius et al., 1999; Boothroyd et al., 2016) that needs to be factored into leakage reports.

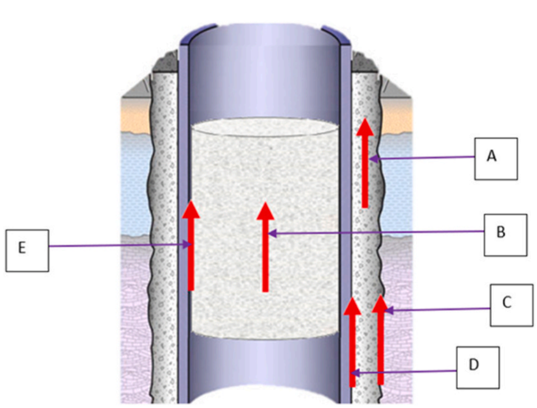


Fig. 4. Potential leakage paths in permanently abandoned wells. Adapted from (Vrålstad et al., 2019).

To understand the impact of oil and gas wells on underground water contamination (Hudak and Wachal, 2001), analysed samples from water wells in the South Eastern part of the Gulf coast Aquifer in Texas to determine the possible contribution of poorly abandoned wells to water contamination in the area. The authors proved that proximity to oil and gas wells increased the chloride and bromide ion concentrations of water from neighbouring wells. The studied area had 20,877 plugged and abandoned wells whose contribution to water contamination could have occurred while they were in production or after a poor abandonment operation that allowed for upward brine migration of reservoir fluids.

Additional studies are necessary to understand the impact of poor abandonment practices on the productivity of neighbouring wells.

1.3. *Current engineering standards, practices in the North Sea, Gulf of Mexico, Canada … and others*

The essence of well plugging and abandonment:

- Ensure long term well integrity and prevent the leakage of hydrocarbons into the environment
- Prevent inter reservoir movement of hydrocarbons that could pressure charge reservoirs
- Prevent aquifer contamination and
- Removal of well heads that could constitute a hazard especially to marine navigation (Liversidge et al., 2006: King and Valencia, 2014).

However, there were no regulations on well abandonment in the early years of exploration and production of oil and gas. In the 1890s when the first regulatory laws were made in Pennsylvania, the regulations aimed to protect the oil-bearing formation from contamination by freshwater (NPC North American Resource Development, 2011; Thomas, 2001), a contrast to contemporary requirements. Hydrocarbon leaks from wells abandoned in the 1890s could be attributed to poor abandonment practices arising from this prioritization of the oil reservoirs over fresh water and the environment. The following decades led to significant development of plug and abandonment regulations across the USA and other oil producing countries (Pennsylvania Department of Environmental Protection, 2010; Pennsylvania Department of Environmental Protection, 2018).

Drilling activities continued for about 26 years in Texas before the Texas Railroad Commission gained regulatory RRC authorities over plugging and abandonment operations in 1919. The 1919 RRC regulations was described in the commission's article 3 and required the plugging of abandoned wells in a manner that prevents the exchange of reservoir fluids between strata. Environmental protection had not become a major concern for the industry at the time and most regulations were designed to prevent the loss of oil and gas into other strata.

These requirements were constantly updated in Texas with similar developments in other states in the USA with the RRC issuing specific instructions for cementing and requiring the plugging of freshwater strata in 1934 and 1957 respectively (NPC North American Resource Development, 2011). Thomas (2001) discusses additional historical development of plug and abandonment regulations in the United States.

A major highlight of the regulations in the states is their decentralisation. This gives room for variations in requirements and enables the adaptation of regulatory requirement to meet the specific challenges of each state's terrain and geology. In addition, this also means that P and A regulations could be designed in consideration of the drilling and production practices under which fields in each state were developed.

Fig. 5 shows the differences in regulatory requirements by states.

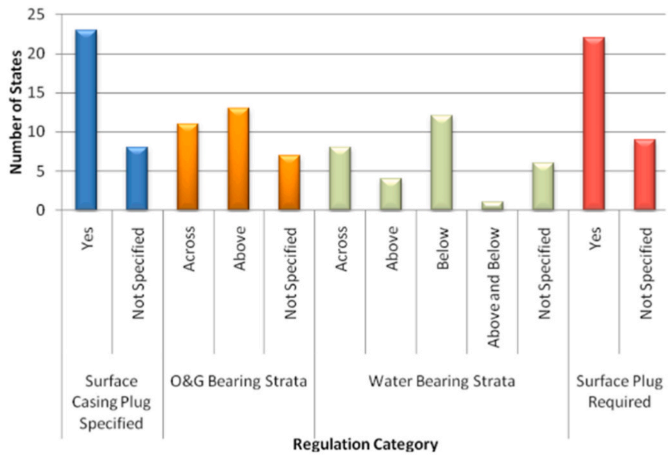


Fig. 5. Variations in well plugging regulations across the states of USA (North American Resource Development, 2011).

Water bearing strata for instance, are required to be plugged above, across, below, below and above. In the case of about six states in the set, no specification has been given. 12 states in the data set consider a plug below the water bearing strata sufficient while 1 state requires plugging above and below the water zone.

A similar situation obtains in Canada where plug and abandonment of wells is carried out in accordance with the Alberta Energy Regulator's guideline in the provinces of Alberta and British Columbia (Trudel et al., 2019) but regulated by the Office of the regulator of Oil and Gas Operations in the Northwest territories (OROGO, 2016). In countries like Nigeria, the regulations on plug and abandonment of oil and gas wells are still work in progress with certain degrees of vagueness especially in defining who bears the cost of decommissioning a well (Dike, 2017, 2017; Offshore Network, 2019).

In the U. K sector, plug and abandonment operations are carried out in accordance with UK Offshore Operators Association Guidelines for Suspension and Abandonment of Wells. Plugging and abandonment in the Norwegian and Dutch sectors are carried out in accordance with NORSORK/PTIL D-010 standard and the Dutch mining authority guidelines respectively (Liversidge et al., 2006). Differences in regulations are often determined by the stated goal of permanent plug and abandonment of wells (Van der Kuip et al., 2011; Trudel et al., 2021).

As shown in Table 1 which compares regulatory requirements for permanent plug and abandonment of wells in selected countries and states, significant variations occur in regulations. However, there doesn't seem to be any well researched basis for these differences from a mechanical or physical point of view (Van der Kuip et al., 2011). What seems obvious though, is that regulatory requirements are affected by each country's operating environment and the role the regulatory document is expected to play. In the U.K where the regulatory guidelines seem to be a recommendation of best practices, the requirements are more advisory in tone while the NOSORK regulations seem more specific and authoritative.

A generic summary of the requirements for plug and abandonment in the states of the USA is represented in Fig. 6 below. As discussed earlier the development of plug and abandonment regulations in the United States progressed at varying paces across the states and developed under different regulatory authorities.

Offshore environments have tougher regulations than onshore fields. While this might mean an extra monetary cost on operators, the cost of remedial P and A jobs and the associated risk to aquatic life from poorly abandoned wells outweighs the added cost.

The current practice of abandoning reservoirs targeted at restoring the cap rock integrity with cement as shown in the diagram below exposes potential leak paths through the primary cement, cement/casing

Table 1
A summary of regulatory requirements for permanent plug and abandonment in selected countries.

Regulation/ Regulation	Barrier requirements in open hole	Barrier requirements in cased hole	References
United Kingdom			
United Kingdom/ OGUK Guidelines on decommissioning 2015	2 independent plugs of at least 100 feet about 30.4 m measured depth of good quality cement, typically 500 feet MD. For a single continuous barrier, a plug must be at least 200 feet of good cement, but typically 800 feet MD.	2 independent plugs of at least 100 feet of good quality cement each, typically 500 feet. Acceptable if the annulus is confirmed to contain at least 100 feet of quality cement opposite each plug.	(Oil & Gas UK, 2021; Anne Lene Blom Oksnes, 2017); (Liversidge et al., 2006)
Norway/Well Integrity in drilling and well operation, Norsok (2013)	100 m MD of good quality cement minimum 50 m MD above any source of inflow/ leakage point. A plug-in transition from open hole to casing should extend at least 50 m MD above and below casing shoe (NORSOK D-010, 2013).	50 m MD if set on a mechanical/ cement plug as foundation, otherwise 100 m MD (NORSOK D-010, 2013). A minimum of 2 independent barriers are required for hydrocarbon bearing zones and any abnormally pressured zone with potential for flow to surface.	(Norsok, 2013; Liversidge et al., 2006; Anne Lene Blom Oksnes, 2017)
Denmark/DEA Guidelines for drilling-exploration	At least 50 m of good cement below and above the individual zones. Where there is an open hole below the deepest casing, a cement plug shall be placed in such a manner that it extends at least 50 m above and below the casing shoe.	Where possible, for perforated zones, shall be isolated with cement plugs placed across the zones and extending at least 50 m below and above the lowest and topmost perforations respectively. Liner: the plug shall extend at least 50 m above and below the point of suspension.	Danish Energy Agency (2009)
Canada			
Alberta and British Columbia/Alberta Energy Regulator's Guidelines	A minimum of 15 vertical meters above oil bearing formations starting from TVD. Additional plugs should be set to a minimum of 15 vertical meters above deepest set casing shoe.	15 m of cement plug below the bottom and above the top of reservoir. A permanent bridge plug set within 15 m above the reservoir and cap with 8 m of cement is also acceptable.	(AER, 2016; Trudel et al., 2019)
Northwestern Territories/Orogo, 2016	Open hole wells are not addressed in the OROGO 2016 guidelines. Cased wells are	Wells with cemented liner, require a permanent bridge plug within 15 m	(OROGO' 2016)

(continued on next page)

Table 1 (*continued*)

Regulation/ Regulation	Barrier requirements in open hole	Barrier requirements in cased hole	References
	rather classified into two levels. level 1 wells contain acid gases, have reservoirs of at least 0.8psi/foot pressure gradient or require Blow out preventer equipment rated >10,000 pPsi. All other wells are classified as level 2.	above the liner top and a cement plug extending at least 15 m below and above the liner top. Level 1 wells with previous squeeze cementing, or casing failure require a permanent bridge plug within 15 m above the interval and circulating 30 vertical meters of cement or a cement plug and squeezing cement a minimum of 30 vertical meters below and above the top of the interval. For level 2 wells with similar issues, setting a permanent bridge plug within 15 m above the interval and circulating 15 vertical meters of cement or setting a cement plug and squeezing cement from a minimum of 15 vertical meters below and above the top of the interval is acceptable for permanent abandonment. For perforated cased holes, the required length of cement is 60 m for level 1 wells and 30 m for level 2 wells	
United States of America			
Pennsylvania/ Pennsylvania Department of Environmental Protection guidelines	50 feet below each water, oil, or gas bearing formation extending 50 feet above the zone	50 feet below each water, oil, or gas bearing formation extending to 100 feet above the zone OR an approved mechanical plug set 20 feet above the stratum.	(Pennsylvania DEP 2018)
Texas/Texas Railroad Commission	Cement plug extending across the productive zone to least 50 feet MD below and above the zone with an additional 10% slurry volume per 1000 feet MD to the plug base	At least 100 feet of plug material with an extra 10% volume of slurry per 1000 feet MD to the plug base.	(RRC Texas, 2021)

and cement/formation bond interfaces as shown in Fig. 7. The development of a hybrid barrier aimed at isolating reservoir fluids at source could potentially provide permanent integrity by shutting off exposure paths between aggressive reservoir fluids and cement/casing.

1.4. *Typical well conditions and well types*

The complexity of the terrain, wellbore trajectory and geological formations encountered during exploration and development of a field affects the design and execution of well plug and abandonment on the field.

Oil and gas wells are classified based on their trajectory, on their reservoir pressure and temperature and on the nature of the formations drilled. This work will cover a review of special well types and the impact of their challenging conditions on plug and abandonment.

Oil and gas wells can also be classified as either conventional or unconventional. According to Ma, Y. Z. (2016) unconventional wells are wells drilled to produce from unconventional resources such as those located at extreme depths, abnormally high temperature and pressures, significant percentage of corrosive gases, heavy oil and tight reservoirs such as shale. In addition to challenges associated with drilling and completing unconventional wells, they pose special challenges to well integrity (Kiran et al., 2017) and impact the long-term stability of well barrier elements during production and post abandonment.

1.4.1. *HPHT wells*

The classification of oil and gas wells as HPHT (High pressure, high temperature) varies from one region to another. The American Petroleum Institute API, classifies a well as a high pressure well if it has pressures in excess of 15000 psi and high temperature if the well has a temperature in excess of 350 °F. This was published in the API guidelines technical report, 1PER15K-1 (America Petroleum Institute, 2013).

On the other hand, NORSOK (Norsok, 2013) classifies a well as High pressure if it has a shut-in pressure in excess of 10,000 psi and a HT well as one having a temperature greater than 300 °F. This is aa significantly more conservative classification than the API standard. The U.K guidelines, Table 2 is in between these two and classifies as a well as high pressure if it has a reservoir within the range of 10,000 to 15,000 psi and a high temperature well as one having a temperature value between 266 and 392 °F.

A relatively more universal system is the Schlumberger classification illustrated in Fig. 8 below (Debruijin et al., 2008) alongside the OGUK classification in Table 2 for comparison purposes. In addition to reservoir pressures and temperature, it provides the reservoir depths. This enables the calculation of pressure and temperature gradients which gives better insight for design of drilling and well abandonment hydraulics. A fouth group of wells classified as HPHT-hc have static reservoir temperature and pressure above 260°C and 35,000 psi respectively.

HPHT wells present special challenges during drilling and in well plugging abandonment; limits the selection of barrier materials components, have narrower pressure windows between formation and fracture pressures, and necessitates the use of more retarders in the cement slurry to prevent the negative impacts of high temperatures on cement. These temperature and pressure conditions also present significant challenges to the interfacial bonds between cement and casing arising from varying thermal conductivities and creates thermal stresses that could lead the factures in cement and compromise integrity in

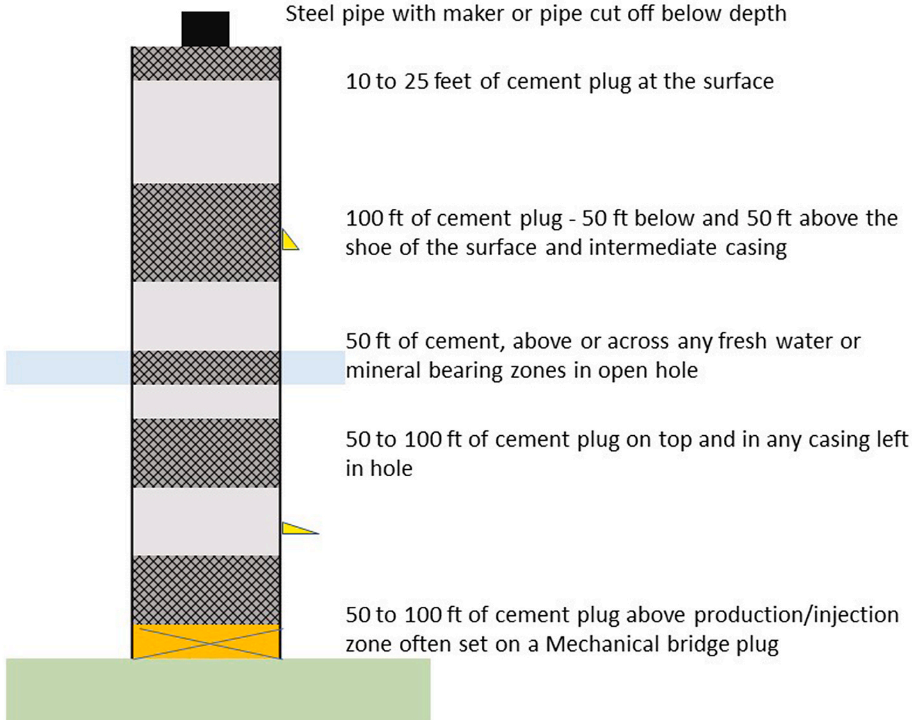


Fig. 6. Generic requirements of plugging and abandonment requirements in most USA states adapted from (Herndon and Smith, 1976)

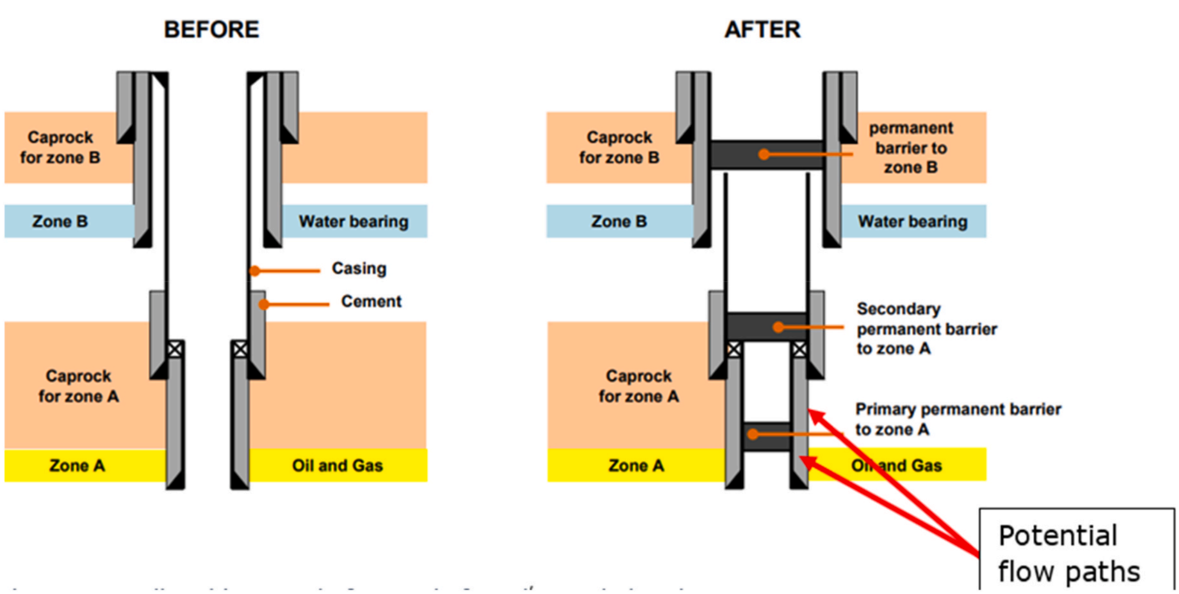


Fig. 7. Well architecture before and after plug and abandonment adapted from (OGUK, 2015a, 2015b, 2015c) with modification to show potential leakage post abandonment leakage paths.

abandoned well. The impact of corrosive gases is also increased in high temperature environments with possible compromise of long-term integrity of well barriers.

Readers may refer to (Wang, Q. et al., 2014; Wang et al., 2014; DeBruijin et al., 2008; Baohuaa et al., 2013; Frittella et al., 2009; Gjonnes and Myhre, 2005; Olutimehin and Odunuga, 2012; Moraes et al., 2013; Haidher, 2008; Mohammed et al., 2019) for additional knowledge on the impact of High temperature and pressures on cement slurries, cement plugs and long term well integrity.

1.4.2. Shale oil and gas wells

Economic production of oil and gas from shale formations is one of the biggest technological achievements of the oil and gas industry in the 21st century (Wang et al., 2014; Hughes, 2013). To achieve this, the industry has adopted a combination of horizontal drilling and hydraulic fracturing technologies because of the very low permeability of shale formations (Zhou et al., 2019; Liu, K. et al., 2017; Mohammed et al., 2019).

The hydraulic fracturing of these long horizontal sections has significant impacts on both casing and annular cement integrity that could lead to complications in the design and implementation of permanent

Table 2
OGUK classification of North Sea wells based on reservoir temperature and pressure adapted from (OGUK, 2015a, 2015b, 2015c).

Well type	Depth range m (ft)	Typical Conditions		
		Initial pressure range at reservoir, MPa (psi)	Temperature range at reservoir °C (°F)	Temperature range at surface °C (°F)
Shallow	1500 to 3000 (5000–10000)	15 to 35 (2000–5000)	40 to 100 (104–212)	0 to 10 (32–50)
Medium	3000 to 4500 (10000–15000)	30 to 60 (4000–9000)	80 to 150 (176–302)	0 to 10 (32–50)
Deep	4500 to 6000 (15000–20000)	40 to 70 (6000–10000)	130 to 150 (266–302)	0 to 10 (32–50)
HPHT	3000 to 6000 (10000–20000)	70 to 105 (10000–15000)	130 to 200 (266–392)	0 to 10 (32–50)
Ultra HPHT	3000 to 6000 (10000–20000)	105 to 140 15000 to 20000)	200 to 300 (392–572)	0 to 10 (32–50)

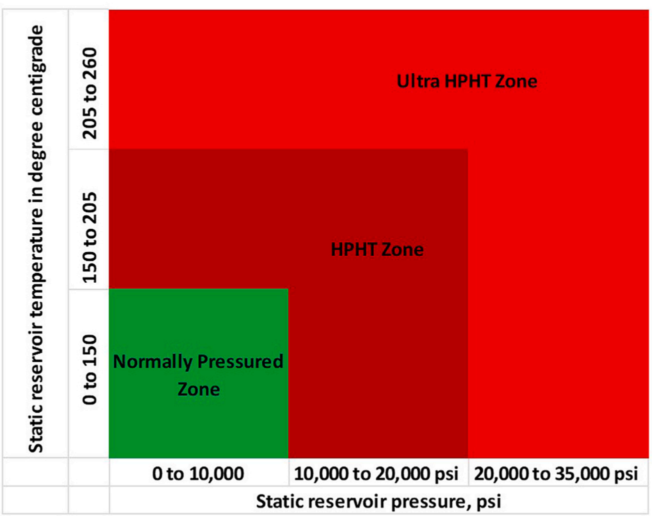


Fig. 8. A proposed model for classification of oil and gas wells based on reservoir temperature and pressure. adadpted from (DeBruijin et al., 2008).

plug and (H. Liu et al., 2017). Alternating thermal loads, decrease the axial and radial bonding strength between cement and casing and cause the development of micro annuli in cement sheaths. These effects accelerate the degradation of cement and result in well integrity issues due to cement sheath failures (Liu, K. et al., 2016; Liu et al., 2018; Shadravan et al., 2014; Wang, W. and Taleghani, 2017).

When these failures occur around gas bearing formations, it leads to sustained casing pressures. To contextualise the impact of hydraulic fracturing on the integrity of cement sheaths, studies by (Liu et al., 2018; Williams et al., 2011) on hydraulically fractured wells in the Fuling shale of China and the Marcellus shale of the United States observed sustained casing pressure in about 25% and 86% of wells in the regions respectively.

Liu et al. (2017) developed a novel elastic–plastic model that describes the stress regime in cement sheaths imposed by hydraulic fracturing. For a comprehensive study, the author incorporated the impact of drilling, cementing and temperature alterations in the well system during the hydraulic fracturing to establish a model that describes the stress cement sheaths are subjected to in shale wells.

For a successful plug and abandonment of shale wells, operators must account for the possible loss of integrity from hydraulic fracturing, identify the failure locations and factor these into their well decommissioning plans. Any remedial jobs on well integrity prior to abandonment leads to additional costs and failure to correct these integrity issues prior to abandonment is a potential source of failure to long term zonal isolation in the well system.

Formation creep, a common condition with certain groups of shale, is another factor that affects cement integrity in oil and gas wells. This factor has often been ignored in conventional long term cement casing formation system studies. It's impact on long term integrity of cement was recently investigated by Zheng et al. (2021) and reveals a significant contribution formation creep to the failure of cement at the cement casing interface. The plastic creeping formation increases the difference between radial and tangential stresses for the cement sheath and the probability of shear failure at cement-casing interface. The negligence of formation creep in conventional studies of cement failure can lead to underestimation of failure.

This improved understanding cement failures due to formation creep could be considered as further elucidation of some aspects of the results of studies by (Ford et al., 2017) which identified the cement-casing interface as a high risk surface for leakage from abandoned wells. It provides additional insight into the causes of sustained annular pressures in certain wells. While this study is not representative of what happens to permanent cement plugs placed on mechanical plugs inside the casing as a result of the additional protection from the casings mechanical properties, it is indicative of the long term situation of cement behind casing. Given that conventional P and A operations often leave possible communication pathways between reservoir fluids and casing/cement behind casing, the risk of fluid leakage to surface remains significant in well abandoned without proper consideration of formation creep.

In addition, the impact of pressure depletion during production and possible pressure builds up post abandonment on the movement of cap rock should be subject for further studies especially in wells produced under poor reservoir management practices. In fields where several wells are drilled at various angles to produce a single or multiple reservoirs, the work of (Zheng et al., 2019) on the anisotropic strength of shale is useful for understanding the shale behaviour at defined pressures and given inclination (Zheng et al., 2021). identifies improving the Young's modulus and poison ratio of cement as remedial measure to impact of creeping formation. This opens up another possible research question on the subject of continued use of Portland cement as barrier material and the possible impact of improvements in other mechanical and thermal properties of barrier materials on their long-term performance. Examples will be the thermal distortion resistance of the barrier material, its compressive strength and fracture toughness.

A Flexible, Expanding Cement System (FECS) has proven effective in the ensuring zonal isolation across Marcellus shales in Pennsylvania (Williams et al., 2011). While this system was developed to prevent sustained casing pressures in compliance with the state's strict regulations, its mechanical properties could be further investigated for use as a permanent plug and abandonment material in shale wells and other wells where interfacial debonding of barrier materials have proven to be a challenge.

1.4.3. High angle and horizontal wells

The main challenge with plug and abandonment of high deviation and horizontal wells lies with the placement of well barriers for satisfactory zonal isolation (OGUK, 2015a, 2015b, 2015c).

A significant proportion of ageing wells requiring abandonment in most countries at the moment are vertical wells. However, trends in British Columbia are already indicate a growing number of deviated and horizontal wells coming into the abandonment phase. As mentioned earlier, the shorter productive life of horizontal wells will lead to significant increase in the abandonment of horizontal and deviated wells in the years ahead especially in countries like Canada and the USA where exploration for shale oil and gas have required the drilling of several horizontal wells.

Trudel et al. (2021) analysed abandoned wells in British Columbia. Fig. 9 below shows a gradual start of abandonment of vertical wells

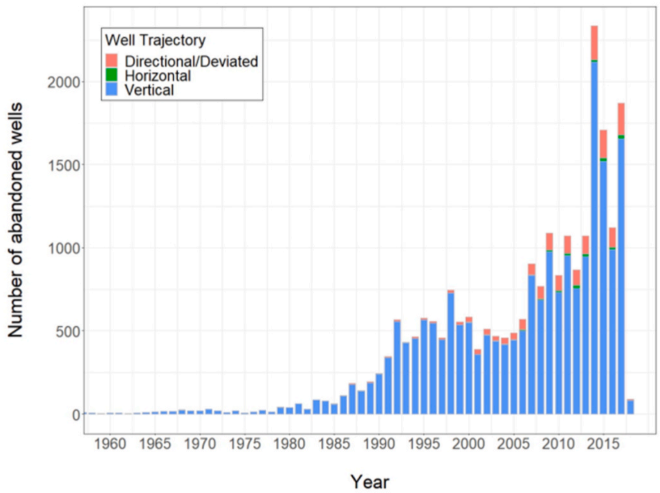


Fig. 9. A yearly distribution of abandoned wells in Alberta based on well types/trajectories (1955–2015) (Trudel et al., 2021).

followed by an addition of deviated wells into the abandoned wells mix in the late 1980s and horizontal wells in the mid-2000s. The general outlook of the types of wells to be decommissioned in the years ahead will be a mixture of horizontal, vertical and deviated wells in varying terrains. The oil and gas industry will need to continually develop ready to deploy technical and materials solutions for effective abandonment of these wells. Existing regulatory requirement and guidelines will also require constant review to ensure effective permanent zonal isolation.

2. Plug and abandonment materials

A major contributor to the leakages from abandoned wells discussed in earlier sections, is the failure of P and A materials. This has often resulted in the leakage of greenhouse gases and other forms of hazardous fluids from abandoned wells (Benedictus et al., 2009).

To qualify as permanent barrier for well P and A, a material should meet the following criteria (OGUK, 2015a, 2015b, 2015c):

- Possess very low permeability when it sets to prevent the flow of fluids through the bulk material
- Develop sufficient bond with adjacent materials in the wellbore such as casing and rock formations at barrier placement depth to prevent flow fluid through the interface
- Retain integrity over a long period of time for permanent zonal isolation
- Long term stability to downhole fluids under prevailing and foreseeable downhole thermobaric conditions
- Possess mechanical characteristics that can withstand compressive and tensile loads that exist or may arise downhole.

Every well barrier material should provide a sealing effect, be placeable at preferred depths in the wellbore, be able to set and stay at the preferred position, stay durable in the long term under prevailing and foreseeable downhole condition and should meet local regulations on health and environmental safety.

The intermolecular bonds among particles of the well barrier material and the interfacial bond existing between barrier materials and the surrounding surfaces are both essential to long term zonal isolation. Studies on bonding and debonding often focus on the interfacial bonds but the intermolecular bonds are equally important for understanding the ability of materials to serve as permanent plug and abandonment materials and define the limits of operating conditions for their usefulness. The integrity of the well prior to abandonment is also a major contributor to the achievement of permanent zonal isolation.

Table 4 below summarizes the classes of material used for permanent plug and abandonment of oil and gas wells and the mandatory test required for each materials group's qualification as permanent barriers.

The testing required for each material group is affected by the hardening process and the mode of mass transportation through the barrier material and are designed to ensure that the selected materials are able to withstand downhole conditions and prevent leakage of reservoir fluids through the barrier material, the interface between the barrier and the casing or the interface between barrier material and formation.

Material degradation can occur over time and result in failures at one of the bonding joints leading to compromise of well integrity. Given that well barrier materials are placed downhole with usually no intention for re-entry for evaluation post abandonment, it is important to ensure that the well geometry and reservoir conditions and content are understood and factored into the materials testing and qualification process for permanent plugs.

In the following sections the qualifying properties of these materials reviewed to identify their main characteristics and potential weaknesses as well barriers for P and A.

2.1. Portland cement as a plug and abandonment material

Portland cement has a long history with the oil and gas industry and has gained a reputation in both drilling and well abandonment as a choice material for establishing well integrity and zonal isolation. It is the most used well barrier material for permanent plugging and abandonment of oil and gas wells.

The main components of Portland cement are CaO, SiO_2, Al_2O_3, and Fe_2O_3. Clinkers make up over 90 percent of the cement in combination with a limited amount of calcium sulphate that controls the rate at which the cement sets. Their production involves high temperature processing of hydraulic limes resulting in the combination of Ca_2SiO_4, belite and calcium oxide, CaO to form Ca_3SiO_5. The temperature range for the process is in orders greater than 1300 °C.

The clinker contains 4 major mineral phases: 50–70% tricalcium silicate ($3CaO{\cdot}SiO_2$ or "C_3S"), 15–30% dicalcium silicate ($2CaO{\cdot}SiO_2$ or "C_2S"), 5–15% tricalcium aluminate ($3CaO{\cdot}Al_2O_3$ or "C_3A") and 5–10% tetracalcium aluminoferrite ($4CaO{\cdot}Al_2O_3Fe_2O_3$ or "C_4AF''") (Vrålstad et al., 2019).

The process of applying Portland cement in well abandonment operations requires that the cement be converted into a pumpable slurry. This process involves the addition of water leading to a reaction with calcium silicates to produce a gel like layer that inhibits further reaction to give room for pumping before the setting of cement slurries into solid plugs. The aluminate and ferrite minerals in the composition of Portland cement behave differently and require the calcium sulphate minerals such as gypsum, anhydrite, hemi-hydrite, to control their setting period.

Detailed explanation of clinker thermochemistry and curing process of Portland cement are discussed in the following works (Dylan, 2013; Taylor, 1997; Hewlett and Liska, 2019).

The initial use of Portland cement in the oil and gas industry was for primary cementing during drilling which has been extensively discussed in literature (Jones, P. H. and Berdine, 1940; Lavrov and Torsæter, 2016; Nelson et al., 1990). These early applications were construction cement and become the earliest API classifications of oil well cement; A B and C. Deeper wells of higher temperatures required cement with longer solidifying times, hence the development of API classes D, E and F. A later group of specialized oil well cements, API classes G and H, have been developed and are the most used in the oil and gas industry.

Portland cement is used in combination with certain materials called additives, Table 3, to achieve desired properties for specific applications. Table 4 below summarizes key cement additives and their effect on slurry and cement sheath or plug. The choice of additives is dependent on well conditions and the desired long-term property of cement plugs. Additional information on oil well cement additives can be found in the

Table 3
Cement additives and their impact on cement properties.

Additives	Impact on cement properties	References
Barite, ilmenite and hematite	Increase in slurry density	(Ahmed et al., 2020; Ahmed et al., 2019)
Latex and micro silica	Permeability reduction to produce gas tight cement	(Thakkar et al., 2020; Stynoski, Mondal and Marsh, 2015; Jones and Carpenter, 1991)
Magnesium oxide and calcium oxide	Expansion agents	(Jafariesfad, Geiker and Skalle, 2017; Mazurok et al., 2017; Srivastava, Ahmed and Shah, 2018)
Silica flours	Increase in thermal stability	(Murtaza et al., 2013; Souza et al., 2012)
Carbon fibres	Increase in mechanical strength	(Nguyen et al., 2016; Laukaitis et al., 2012)
Bentonite, spheres of hollow glass	Density reduction and increase of cement yield.	(Medley, Maurer and Garkasi, 1995; Rita, Mursyidah and Syahindra, 2018)
Hydroxyethyl cellulose (HEC), methyl hydroxyethyl cellulose (MHEC), and carboxymethyl hydroxyethyl cellulose (CMHEC)	Water soluble polymers for Fluid loss control	(Mishra et al., 2003; Liu et al., 2021)
Nano silica	4-fold impact including: decreasing porosity and permeability, increases compressive strength and decreases fluid loss	(Thakkar et al., 2020; Yu et al., 2014)
Carbon nanotubes, CNTs	Decrease in Young's modulus, slight decrease in inter friction angle, increase in cohesion factor and Poisson's ratio.	Zheng et al. (2022)

works of (Cadix and James, 2022; Doan et al., 2015; Kovalchuk, V. S. and Nikolaev, 2021).

The use of one or another additive is dependent on the well conditions and the desired long-term property of cement plugs. Additional information on oil well cement additives can be found in the works of (Cadix and James, 2022; Doan et al., 2015; Kovalchuk and Nikolaev, 2021).

2.1.1. Experimental and theoretical models on cement sheath degradation and failures

Studies aimed at understanding and preventing leakage through cement sheaths progressed significantly over the years. The chronology of these studies has been reviewed extensively by (Bois et al., 2011).

Earlier studies on the prevention of leakages from oil wells focused on the bonding between the interfaces along the wellbore. The formulation of cement slurries during this period was based on shear and hydraulic bonds and bond cement pressure concepts developed through laboratory experiments that often failed to achieve leakage prevention in field applications. (Bearden et al., 1965; Carter, L. G. and Evans, 1964; Jordan et al., 1965).

A major shortcoming of these experiments was their inability to differentiate and isolate friction bonding from chemical bonding.

The next group of studies focused on fluid migration through cement while it undergoes transformation from liquid to solid state. This category includes studies on the migration of reservoir fluids though liquid cement and fluid loss from cement into the formation while it sets that could lead to the formation of micro annuli and channels through the cement sheath (Carter and Slagle, 1972; Chenevert and Jin, 1989; Cheung and Beirute, 1985; Webster and Eikerts, 1979). However, these studies could not explain the impact of downhole conditions on the

Table 4
Materials grouping for permanent well barriers and mandatory tests for each group. Adapted from (OGUK, 2015a, 2015b, 2015c).

Type	Material	Examples	Mandatory qualification test
A	Cement and ceramics (setting materials)	Portland cement, pozzolanic cements, slag, phosphate cements, hardening ceramics, geopolymers	Nitrogen permeability, dry mass, expansion/ shrinkage during and after hardening [API RP 10B-5 ring test], differential thermal expansion [ASTM E228], tensile strength [ASTM C 496], UCS[API RP 10B-2]
B	Grouts	Sand or clay mixtures, barite plug, bentonite pellets calcium carbonate, and other inert materials	Nitrogen permeability, dry mass, shrinkage after hardening, differential thermal expansion [ASTM E228], density [pressurized mud balance]
C	Thermosetting polymers and composites	Resins, epoxy, polyester, vinyl esters including fibre reinforcements	Diffusion coefficient, dry mass, expansion/ shrinkage during and after hardening [API RP 10B-5 ring test], differential thermal expansion [ASTM E228], creep [ISO 899–1], tensile strength [ISO 527–1], UCS [API RP 10B-2], shear bond strength [rugosity measured with ASTM D7172], decomposition temperature [TGA/ DTA/DSC measurement], density [ISO 1183–1].
D	Thermoplastic polymers and composites	Polyethylene, polypropylene, polyamide, PTFE, PEEK, PPS, PVD, and polycarbonate including fibre reinforcements	Diffusion coefficient, dry mass, expansion/ shrinkage during and after hardening [API RP 10B-5 ring test], differential thermal expansion [ASTM E228], creep [ISO 899–1], tensile strength [ISO 527–1], UCS [ISO 604], shear bond strength [rugosity measured with ASTM D7172], decomposition temperature [TGA/ DTA/DSC measurement], density [ISO 1183–1].
E	Elastomeric polymers and composites	Natural rubber, neoprene, nitrile, EPDM, FKM, FFKM, silicone rubber, polyurethane, PUE and swelling rubbers including fibre reinforcements	Diffusion coefficient, dry mass, expansion/ shrinkage during and after hardening [API RP 10B-5 ring test], differential thermal expansion [ASTM E228], creep [ISO 899–1/ASTM D395], tensile strength [BS EN ISO 527–1], UCS [BS EN ISO 604], shear bond strength [rugosity measured with ASTM D7172], decomposition temperature [TGA/ DTA/DSC measurement], density

(continued on next page)

Table 4 (*continued*)

Type	Material	Examples	Mandatory qualification test
			[ISO 1183–1], stress relaxation [ASTM D395, NORSOK M710]
F	Formation	Claystone, shale, salt	Nitrogen permeability, dry mass and creep [ASTM C512-10]
G	Gels	Polymer gels, polysaccharides, starches, silicate-based gels, clay based gels, diesel/clay mixtures	Preliminary evaluation to confirm the major mode of mass transport through the material, flow or diffusion, Nitrogen permeability or diffusion coefficient test as required, dry mass, shrinkage during and after hardening [API RP 10B-5 ring test], differential thermal expansion [ASTM E228], creep [ISO 899–1], shear bond strength [rugosity measured with ASTM D7172], decomposition temperature [TGA/DTA/DSC measurement].
H	Glass		Dry mass, expansion/shrinkage during and after hardening [API RP 10B-5 ring test], differential thermal expansion [ASTM E228] and thermal shock, UCS [API RP 10B-2], shear bond strength.
I	Metals	Steel, other alloys such as bismuth-based materials.	Dry mass, expansion/shrinkage during hardening [API RP 10B-5 ring test], differential thermal expansion [ASTM E228], creep [ISO 204], tensile strength [ISO 68992–1], UCS [ASTM E9], shear bond strength [rugosity measured with ASTM D7172], decomposition temperature [TGA/DTA/DSC measurement]
J	Modified in-situ materials	Barrier materials formed from casing or combination of casing and formation through thermal or chemical modification	Nitrogen permeability, dry mass, creep [ASTM C512-10

long-term integrity of cement after in sets and the potential degradation of cement over time.

After this period, the industry began to investigate the mechanical behaviour of cement sheaths downhole and the impact of reservoir conditions on these mechanical properties. Studies in the early 1990s by (Jackson and Murphey, 1993; Goodwin and Crook, 1992) investigated the possible reason for flow through wellbore materials that have been exposed to high pressures and flowing temperatures and found that downhole conditions could lead to damage of the cement sheath and consequent compromise of well integrity.

Theoretical and mathematical models have also been developed over the years to study the failure of cement barriers (Thiercelin et al., 1998; Thiercelin et al., 2006; Di Lullo and Rae, 2000; Fleckenstein et al., 2001; Pattillo and Kristiansen, 2002). These models focused on cement volume variations arising from hydration and casing contraction following mud density and temperature decrease in the wellbore as causes of micro annuli development in cement sheaths. The development of these micro annuli was principally attributed to the creation of gaps at the interfaces when cement fails to remould into the induced deformation. While these were helpful to understanding failures at the cement – casing interface, they failed to explain the development of micro annuli within the cement sheath long after it has set. In 2011, (Bois et al., 2011), developed a comprehensive mechanistic analysis based on theoretical and experimental evidence to describe the formation of micro annuli in cement sheaths. Their study blends cement volume variations and heat generation during hydration, mud-density and temperature variations, cement thermo-poro-elasto-plastic behaviour during and after hydration, thermo-poro-elasto-plastic behaviour of the formation, and initial state of stress in the formation to describe the formation of micro annuli in cement sheaths. It sheds light on the response of the cement sheath to reservoir conditions, highlights the need for the selection of right materials in the cement slurry mix and the selection of cement sheath thickness based on downhole conditions. However, it fails to investigate the chemical degradation of cement in the presence of aggressive fluids such as acidic brine, CO_2, H_2S in gaseous form or in solutions and the impact of drilling and formation fluid contamination of cement on development of micro annuli in the cement sheath.

The mechanism of cement degradation by aggressive substances and the impact of contamination on integrity have been studied by various authors. Studies by (Barlet-Gouedard et al., 2006; Barlet-Gouedard et al., 2007; Duguid et al., 2006) indicate a rapid degradation of cement samples with a resulting increase in porosity in the presence of CO_2. An experimental triaxial compression study by (Liteanu et al., 2009) investigated the effect of CO_2 on the failure of Portland cement at reservoir conditions (T = 80 °C, Pc = 1.5–30 MPa) and concludes that weakening of the cement was observed due to injection of aqueous fluid, whereas addition of CO_2 did not further reduce the mechanical strength of the material. While this study investigated the effect of supercritical CO_2 on the compressive strength of Portland cements, it is important to note that the study time, 4 days of the experiment, is too short to describe the long-term impact of CO_2 on permanent cement plugs. The experiment was also carried out using class A cement which is not the common choice cement for the oil and gas industry. Experimental findings on the impact of aggressive medium and temperature on cement has been summarized in Table 5 below.

With the growth in artificial intelligence and machine learning (Zheng et al., 2022a, 2022b), used Support Vector Machine Based Model

Table 5
A summary of the impact of aggressive medium and temperature on cement. Adapted from (Kiran et al., 2017).

Cement Types	Experimental Conditions	Predicted Carbonation Depth in 30 Years (mm)	References
Ordinary Portland Cement, w/c 0.33	CO_2saturated brine	219	Um et al. (2011)
Portland cement with antifoaming agent, dispersant, retarder, and water	CO_2saturated fresh water	113	Barlet-Gouedard et al. (2006)
	Presence of supercritical CO_2	133	
Class H cement, w/c 0.38	pH 2.4, 50 °C pH 3.7, 50 °C	2630 723	(Duguid et al., 2006)
Class H cement in sandstone cylinder, w/c 0.38	pH 3, 20 °C pH 5, 20 °C pH 3, 50 °C	0.93 0.40 1.21	(Duguid, 2008)
Class H cement, w/c 0.38	Presence of supercritical CO_2	1.68	Kutchko et al. (2008)
	CO_2saturated brine	1.0	

and Artificial Neural Network, ANN, Based Model to predict the failure of cement under cyclic loading. The authors employed six publications containing 325 laboratory cement fatigue failure cases from which 14 inputs were drawn for these studies. Seven of these input parameters were cement related factors such type of cement, uniaxial confining stress, curing age, temperature etc while the rest of the fourteen inputs were experimental factors such as loading frequency, number of loading cycles to failure, experimental temperature and pressure etc. The recorded failure prediction accuracy using ANN was 90.78 percent while support vector machine-based model recorded 72.7 percent.

In planning the abandonment of wells with potential post abandonment pressure build up, these studies provide data-based methods to predict cement fatigue failure of the plug materials which could enable the reengineering of material or selection of an alternative. In addition to this, they could be employed for the evaluation of cement behind the casing to understand the quality of existing cement in the wellbore architecture prior to plug placement with potential savings from the cost of cement quality logs.

In HPHT wells, extreme temperature can lead to the debonding of cement from casing (Therond et al., 2016) and the development of cracks in Portland cement from thermally induced stresses (Shadravan et al., 2015; Okech et al., 2015). Cement is brittle and its strength retrogression and deterioration are accelerated at elevation temperatures especially in the presence of aggressive fluids (Al Khamis et al., 2014; Kiran et al., 2017). During steam injections, cement sheaths can experience radial cracking (Dean and Torres, 2002).

Apart from naturally occurring downhole situations, activities such as leak off tests, formation integrity tests and hydraulic fracturing can initiate stress in cement sheaths and compromise integrity. The effect of these operations should be taken into consideration at the planning phase of plug and abandonment operations. In addition, their impact on the complexity of the plug and abandonment operation investigated to determine whether or not a rig or rigless abandonment will be suitable for the well. Wells, with poor cement behind casing and sustained annular pressures and requiring casing milling during abandonment are often the most complex to abandon with compulsory requirement of a rig and its associated extra cost.

2.1.2. *Impact of contaminants on integrity of cement plugs*

Drilling fluids are known for their role in creating primary barrier for well control and maintaining well stability and integrity in addition to several other important functions during drilling and well completion operations. They are generally classified as water-based mud (WBM), oil-based mud (OBM), or synthetic-based mud (SBM). The choice of one over the other in specific operation is determined by several factors including expected downhole conditions and prevailing environmental regulations. Regardless of their very important roles in drilling, drilling fluids could have negative effects on both primary well cementing and cement plugs for permanent plug and abandonment.

The contamination of cement slurry by drilling and completion fluids occurs either from the mixing of cement slurry with drilling fluids, the incursion of dehydrated drilling fluids into cement slurry or contamination by uncleaned filter cakes. Either of these has significant impact on the quality of primary cementing jobs, cement plug placement and the mechanical properties of cement plugs (Oyibo and Radonjic, 2014). This could lead to the development of leakage channels through the bulk material and interfacial contacts between cement sheaths and surrounding materials and consequently compromise long term integrity of cement plugs.

Given that cement slurries are denser than drilling fluids, the lighter drilling fluid tends to migrate upwards through the cement slurry before it sets. This process leads to the creation of flow paths in the cement sheath that could compromise integrity of cement plugs (Isgenderov et al., 2015). Proper cleaning of wellbores and drilling fluid displacement prior to cementing and plug placement are essential to successful plug placement and long-term integrity. Drilling fluid contamination problems in horizontal and highly deviated wells are further complicated by the settling of drilling fluids' solid on the lower side of the deviated/horizontal sections of wells and a free water layer from cement slurry on the upper side of the section (Borsheim, 2016). This complicates the wellbore cleaning process and worsens channels creation arising from density differentials.

(Miranda et al., 2007) observed large fractures and cracks on cement plug slices while (Aughenbaugh et al., 2014) observed a decrease in the compressive strength of all the types of cement contaminated with Synthetic based drilling fluids. A study of the impact of OBM contamination on cement by (Soares et al., 2017) discovered that OBMs, even at low concentrations, lead to a decrease in compressive strength of cement plugs and an increase in yield point and viscosity of contaminated slurry.

Observations of decreased compressive strength in SBM contaminated cement have been attributed to a chemical reaction taking place between SBM and cement that could be mitigated with alkali additives. The negative effect of OBM contamination can be reduced significantly by the addition of alkanolamide a partially water-soluble substance that does not interfere with the hydration of cement and ethoxylated nonylphenols (ENP). Table 6 summarizes studies on the impact of mud contamination on cement and possible mitigations.

Another factor that could contributes to leakage through cement is the length of the cement sheath. A study by (AL Ramadan et al., 2019) developed a robust leakage model for plug and abandonment applications that revealed the role of length of cement plugs in controlling the leakage of reservoir fluids to surface. Differential pressure around the cement plug also affects leakage time. Longer cement plugs of lower permeability, excellent bonding and a lower differential pressure around the cement plug combine to achieve long term integrity in abandoned wells. In the industry, operators would in some instances opt to pump longer columns of cement than stated in guideline documents to improve barrier assurance. Up to 500 ft of good quality cement can be pumped in place of regulatory guideline's 100 ft requirement. However, this means longer operation time, additional materials and consequently higher cost.

While it is important to design cement plugs with the right materials to develop sufficient mechanical strengths and establish sufficient bonding with casing and formations using various additives, the industry is beginning to focus on the development of flexible and self-healing Cementous materials. The ability of such materials to regain integrity when subjected to certain degrees of damage could be the answer to permanent integrity in abandoned wells. Section 2.1.5 of this work has been dedicated to reviewing progress in the development of flexible and self-healing cement.

Table 6
Impact of drilling fluid contamination on cement and possible mitigations.

Nature of drilling fluid	Impact of cement	Possible mitigation	References
Synthetic based mud	Development of cracks and fractures in cement plugs Decrease in compressive strength of cement plugs	Use of adequate spacers or mechanical plugs to isolate cement from SBM Use of alkali additives Addition of geopolymers to the cement mixture	Miranda et al. (2007) (Aughenbaugh et al., 2014; K. Liu et al., 2017)
Oil based mud	Decrease in compressive strength of cement plugs	Alkanolamide ethoxylated nonylphenols (ENP).	Harder et al. (1993) Soares et al. (2017)
Drilling fluid solids in deviated and horizontal well sections	Poor placement of plug with potential creation of leakage paths through fluid channels	Use washing fluid of adequate yield strength or use of multiple washers	Yetunde and Ogbonna (2011)

2.2. Geopolymers as a plug and abandonment material

In search for cementitious materials that are more resistant to degradation in high acidic and brine environments than Portland cement, the oil and gas industry and researchers have been studying and testing geopolymers as an alternative permanent barrier for well abandonment. Geopolymers are binders developed through a synthesis reaction between aluminosilicates and alkaline hydroxide solutions and or soluble silicate. The first known use of the word geopolymer is believed to have originated from Joseph Davidovits (1982) whose work (Davidovits, 1991) describes the synthesis of geopolymers in detail. For additional information and understanding of the chemistry and technology of synthesizing geopolymers, readers may refer to (Xu and Van Deventer, 2000; Amritphale et al., 2019; Duxson et al., 2007).

In summary, the synthesis of geopolymers takes places in three stages:

Depolymerization/Dissolution– hydroxide ions, OH^- in the alkaline solution attacks aluminosilicates to generate silanol groups, Si–O–H groups, in a reaction that leads to the dissolution of Al–O and Si–O bonds in aluminosilicates. **Transportation/orientation** – During this stage, oligomers are produced due to the accumulation of ionic species, an increasing contact between silanol groups and the orientation of the dissolved products. **Polycondensation/geopolymerization** – the oligomers interact with each other to form an amorphous to semi-crystalline 3-dimensional aluminosilicate framework structures by the combination of $[SiO_4]^{4-}$ and $[AlO_4]^{5-}$ tetrahedra (Khalifeh et al., 2018; Singh and Middendorf, 2020).

Very often, the source material for synthesizing geopolymers are waste materials form industrial or agricultural processes. Typical examples include coconut ash, rice husk ash, fly ash, silica fume, calcined clay (metakaolin a calcined form of kaolin is very common source material for geopolymerization). Source material and the choice of alkaline solution have significant effect on the properties of geopolymers (Hassan et al., 2018; Mellado et al., 2014; Luukkonen et al., 2018; Zibouche et al., 2009). A major challenge associated with the preparation of conventional geopolymers is the handling of concentrated aqueous alkaline hydroxide. This challenge has led to studies on the development of one part alkali activated materials in which the reagents are in solid form and require a simple addition of water like in ordinary Portland cement. A detailed review of progress in this synthesis process, the curing mechanism, the physical and mechanical products of the one-part alkali activated materials was carried out by (Luukkonen et al., 2018) who recognized their possible advantage over conventional geopolymers.

Geopolymers have superior qualities than Portland cement in terms of stability in corrosive acidic environments (Bakharev, 2005; Lloyd et al., 2012), stability of mechanical properties at elevated temperatures (Rickard et al., 2011; Kovalchuk and Krienko, 2009), a lower carbon footprint (Patel and Shah, 2018; Salehi, S. et al., 2016) and have a lower degree of shrinkage than Portland cement (Adjei et al., 2022). However, pumpability can become a problem in deep and high temperature wells as a result of short setting times (Khalifeh et al., 2019).

In comparison to ordinary Portland cement, geopolymers contain a high concentration of soluble alkali metals which exposes them to significant levels of efflorescence, a process in which involves the reaction of free metal ions with CO_2 and water to form carbonates (Škvára et al., 2009). The degree of efflorescence in geopolymers is reported in literature as dependent on three major factors: the synthesis condition (mainly temperature) (Škvára, F. et al., 2008; Škvára et al., 2009), raw materials reactivity, and the type of alkali metal (Temuujin and Van Riessen, 2009).

A study by (Zhang, Z. et al., 2014) further explains the impact of these factors on efflorescence in geopolymers and confirmed less and slower efflorescence in geopolymers synthesised through NaOH activation than sodium silicate-activated geopolymers. Higher temperature synthesis also decreased the rate of efflorescence in tested fly ash based geopolymer samples. An additional test on a sample in which 20 percent fly ash was substituted with slag also showed a slower rate of efflorescence.

The process of efflorescence in geopolymers can be summarized in the following equation $CO_2(g) + 2OH^-(aq) \rightarrow CO_3^{2-}(aq) + H_2O$
$2Na^+(aq) + CO_3^{2-}(aq) + 7H_2O \rightarrow Na_2CO_3{\cdot}7H_2O$ (s). The availability of mobile sodium and hydroxide ions in geopolymer binders is the main reason for efflorescence in them (Zhang et al., 2014).

While most available studies on efflorescence in geopolymers are related to their use in the construction industry, the presence of CO2 and water in many oil wells could play a significant role in efflorescence downhole. This should be a major factor considered in the selection of materials and temperature conditions for the synthesis of geopolymers for permanent plug and abandonment applications.

2.2.1. Stability of geopolymers in aggressive solutions and elevated temperatures

The presence of brine and acids in oil fields is has been a cause of corrosion in oil field equipment over the years and a major factor considered in the selection of plug and abandonment materials.

A study by (Dinesh et al., 2018) compared the compressive strengths of fly ash based geopolymer systems to that of class G Portland cement and observed that the geopolymer system developed higher compressive strength than class G cement system in marine conditions. This doesn't not entail a lack of impact on geopolymer systems by salt solutions. It was observed that solutions of potassium, calcium and magnesium chlorides reduced the strength of fly ash kaolin based geopolymers through a chemical reaction that leads to the precipitation of the binder present in geopolymers. The same study observed that solutions of potassium and calcium carbonate produced a different effect on geopolymers leading to an increase in strength over samples that are not saturated with brine solution during a 270-day testing period. Another study by (Nasvi et al., 2014) discovered that increasing the concentration of brine in which a geopolymer was cured for 90 days decreased the degree of mechanical strength decline observed in the geopolymer after the study period. However, it has also been observed that curing in salt water produced geopolymer with greater mechanical strength than curing in normal water (Giasuddin et al., 2013).

A major concern with the use of Portland cement for primary cementing and permanent plug and abandonment operations is their reactivity in acidic environments. Studies have been carried out to understand the impact of sulphuric hydrochloric and hydrofluoric acids on geopolymers and Portland cement.

Sugumaran (2015) studied the impact of 2% and 10% concentrations of sulphuric acid on the durability of geopolymer and observed the acid concentration had an impact on the durability of the material with higher resistance observed in the medium of lower acid concentration. The deterioration of geopolymers in sulphuric acid media was further studied by (Khalifeh et al., 2017) who observed that a geopolymer placed in Brine-H_2S system experienced strength degradation and deformation to an extent where measuring its permeability became impossible. This study was carried for up to 12 months at 212 °F and 145 psi. A control study by the same author indicated a better strength and no mass loss for a geopolymer placed in brine solution for same period of time and temperature at 7250 psi.

Another study of the behaviour of Portland cement and fly ash/silica fume based geopolymer in an acidic medium (Ridha and Yerikania, 2015), observed a 1.76% and 28% reduction in strength in the geopolymer and Portland cement materials respectively. These reductions in strength were interpreted as inversely proportional to the resistance of the barrier materials to acid attack. The hydrochloric and hydrofluoric acids were used for this work with an exposure time of 24 h.

Geopolymers have shown in various studies their properties retention capabilities at elevated temperatures which is an advantage over Portland cement in high temperature wells (Van Oort et al., 2019). The very process of poly condensation occurs at high temperature and the strength of geopolymers improve when cured at high temperatures (Nasvi et al., 2012). agrees that curing temperature affects the strength of geopolymer and suggests an optimum temperature of 140 °F for fly ash based geopolymers. In another study in 2014 (Nasvi et al., 2014), established that rate of polycondensation is slow at low temperatures leading to weak strength in the geopolymers. The authors discourage the use of geopolymers in regions with temperatures lower than 86 °F. The permafrost locations in Russia for instance will be typical example of where strength development will be challenging.

Additional studies by (Igbojekwe et al., 2015) compared the impact of temperature on cement and geopolymer systems. The result of their experiment is summarized in Fig. 10 below which indicates a progressively increasing compressive strength in the geopolymer systems as curing temperature rises. While this positive indicator of geopolymer behaviour in wells within the studied temperature range, the rising trend in compressive strength of geopolymers with curing temperature may not be indicative of what happens beyond the upper limit of the study temperature. Additional studies will be required to understand the behaviour of the geopolymer systems in wells such ultra HPHT where temperatures could reach 572 °F according to (OGUK, 2015a, 2015b, 2015c).

In addition to improving the compressive strength of geopolymers, curing at high temperatures also decreases efflorescence. However, it is important to note that high temperatures accelerate the setting of geopolymers. This reduces pumping time and constitutes a disadvantage in deep wells in ordinary form (Salehi et al., 2019). studied the setting time of fly ash based geopolymer over a temperature range of 150–250 °F and observed a direct relationship between temperature and thickening time. The use of geopolymer plugs in high temperature deep wells, will therefore, require admixtures that slow the thickening rate without compromising the strength, linear expansivity, stability to aggressive media of the geopolymer system.

Alvi et al. (2020) studied the impact of Al_2O_3 and MWCNT-OH nanomaterials on geopolymer and discovered an improvement in both the mechanical strength and thickening time. The thickening time of the nanoparticle enhanced mixture was increased to 3 h at 50 °C and 14.7 MPa in addition to significant improvements in rheology and fluid loss properties of the geopolymer slurry. For additional studies on the impact of nano particles on geopolymer properties, readers may refer to (Guo et al., 2014; Chindaprasirt et al., 2012; Rovnaník et al., 2016; Sumesh et al., 2017; Khater and Abd el Gawaad, 2016; Ridha and Yerikania, 2015). In contrast MCC, microcrystalline cellulose was observed to accelerate the setting time of metakaolin-based geopolymer by 36 min (Rocha Ferreira et al., 2021).

2.2.2. *Shrinkage and impact of drilling fluids contamination*

Another key area of advantage of geopolymers over Portland cement is their possession of a self-expansive characteristics in the presence of water. This was demonstrated in a linear expansion experiment conducted by Rahman et al. at 140 °F and ambient pressure conditions for up to 40 days or 18 and 20 days in other instances. The geopolymer (GP 15) reached a linear expansion of at 0.05% and 0.15% at 1 and 18 days respectively, ordinary Portland cement reached 0.03% and 0.07% in linear expansivity at 1 and 18 days respectively. Refer to Fig. 11.

The difference between cement and geopolymers in this regard is related to the mechanism of the hardening with cement experiencing a volume reduction through a hydration process (Salehi, 2017).

Linear expansivity of well barriers helps establish high quality bonds with surrounding materials such as casing or formation to prevent fluid flow through interfacial contacts. The higher rate of linear expansion observed in the geopolymer in the early days of curing could be a significant benefit in preventing fluid migration through the barrier system while the plug sets.

As discussed earlier, drilling fluids contamination contributes to cement failure, however, research on drilling fluids effect on geopolymers suggest a higher resistance to mud contamination than Portland cement.

After introducing various quantities of OBM into a Portland cement and geopolymer system (Salehi et al., 2016), observed an 88% and 25% drop in strength of the materials respectively while (X. Liu et al., 2017) observed 70% and 10% reduction in the respective systems when exposed to a 10 percent contamination of a synthetic based mud, SBM. Additional studies on the impact of drilling fluid contamination on geopolymers have been carried out by (X. Liu et al., 2017; Eid et al., 2021; Bu et al., 2020; Olvera et al., 2019).

The blending of drilling fluids into geopolymers has been suggested as a sustainable means of mud disposal (Adjei et al., 2022). (Nahm et al., 1994) the conversion a water-based fluid into cement through activation by alkaline materials such as caustic soda and soda ash. Despite its advantages in terms of cost and displacement efficiency, the application of this material was restricted to shallow wells. (Nasvi et al., 2013) affected by water-based mud systems (Eid et al., 2021).

Overall, geopolymers possess good barrier characteristics and resistance to mud contamination. However, the extent of contamination by drilling fluid that will not affect the strength of geopolymers is subject for further research.

Additional studies of the behaviour of geopolymers and their performance as permanent barriers are laid out in Table 7 and Table 8 which summarize existing literatures on the impact of acid medium, alkali concentration, curing temperature and source material on compressive strength, shrinkage and permeability of geopolymers after hardening.

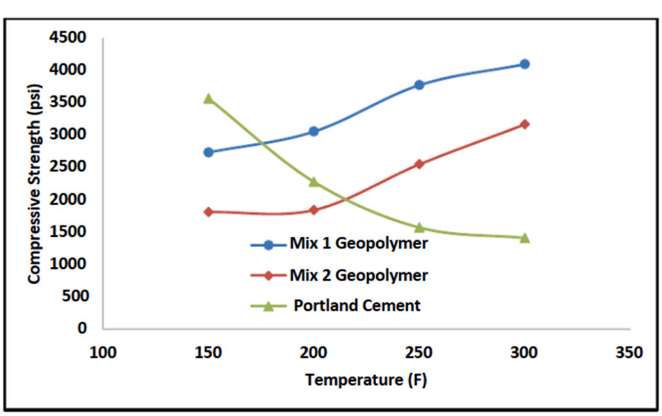


Fig. 10. Strength of class G Portland cement and geopolymers; after 24 h observation (Igbojekwe et al., 2015).

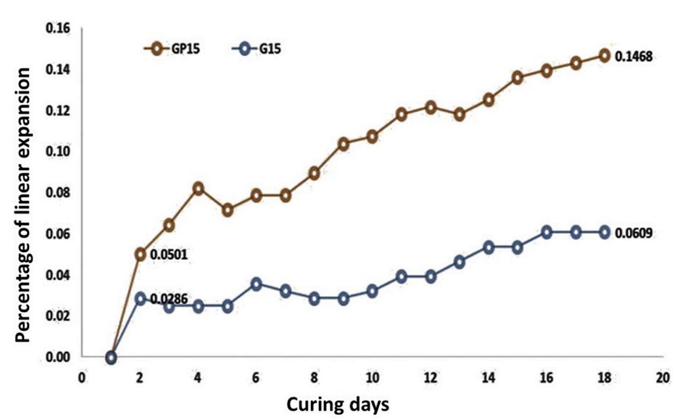


Fig. 11. Linear expansion of geopolymer vs Portland cement. Test temperature, 140 °F (Rahman et al., 2020)

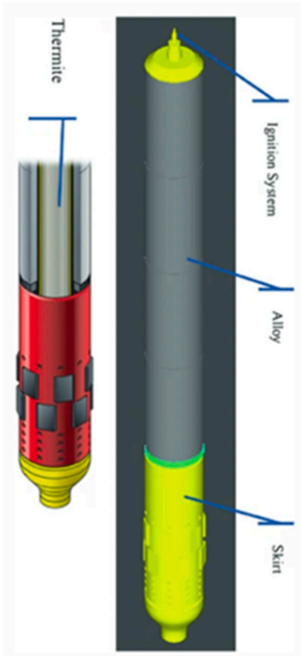


Fig. 12. Major components of a bismuth alloy plug tool using thermite as a heating source (Abdelal et al., 2015).

2.3. Resins as a plug and abandonment material

Polymer resins are one of the major group of materials being considered as an alternative to cement for permanent plug and abandonment solution of oil and gas wells. They are typically composed of a base polymer, a hardener and one or more liquid additives to achieve desired properties such as certain values of viscosity or controlled setting time (Beharie et al., 2015; Jones et al., 2013).

Oil field resins are generally classified as phenolic, epoxy, and furan resins based on their chemical composition (Todorovic et al., 2016). Each of these groups develop sufficient strength to enable their use as well barriers as they transition from liquid to solid state. Beyond chemical composition, another major difference between these groups is in the way their polymerization is triggered. While some are thermally triggered, polymerization in other resins is triggered by acids (Abuelaish, 2012; Zhu et al., 2021).

Earlier application of resins as well barriers was challenged by their incompatibility with aqueous solutions leading to an exothermic reaction that accelerated hardening time. This situation has however been overcome with development of epoxy resin systems that have proven compatible with water even in field applications (Morgan et al., 2010; Jones et al., 2013).

Resins have been used successfully in several squeeze operations to control sustained casing pressure issues in oil and gas wells arising from channels that are impossible to shut off with Portland cement systems. This is because resins are prepared as solids free systems. Another advantage of resins over cement arising from their solids free nature is a simplified mixing system and deployment equipment requirement. Resins' can be deployed in rigless operations; mixed in a batch mixer and pumped downhole using a standard triplex pump (Beharie et al., 2015) and they can be pumped with water-based fluids (Urdaneta et al., 2014) (Jones et al., 2013). This simplified operation cuts down cost on rig rentals and the associated complex mixing equipment.

Other applications of epoxy resins in the oil and gas industry have include sand consolidation, (Marfo et al., 2015; Milkowski and Szwedzicki, 1973), lost circulation material (Knudsen et al., 2014) and for fluid losses control (Teixeira et al., 2014).

2.3.1. Classes of oil field resins

1. Thermally Activated Resins.

This group of resins are designed to set at specific temperature conditions. At the predesigned setting temperature, a crosslinking reaction takes place converting monomers and oligomers into a three-dimensional (3D), high-strength polymer network (Morris et al., 2012) with sealing capacities and sufficient mechanical strength to shutoff leakage pathways in wells. Their setting temperatures can be modified for application in specific reservoir conditions with the help of inhibitors, accelerators and initiators (Knudsen et al., 2014). Epoxy resins are a class of thermosetting resins consisting of an epoxy group and a hardener (Abuelaish, 2012). A reaction between the hardener, often diethylenetriamine, and epoxy produces a hard invert plastic through a polymerization reaction. The epoxy material itself, is product of a reaction between epichlorohydrin and bisphenol A (Kabir, 2001). The read may refer to (Irfan, 2012) for better understanding of the synthesis of epoxy resins.

The Halliburton WellLock, a thermally activated resin system develops a 3D polymer structure through a cross linking reaction between epoxides and an amine hardener. WellLock has been proven to develop a compressive strength between 34 and 103 MPa and tensile strength that could reach 14 MPa and applicable within a temperature range of 16–93 °C. This system was used to successfully applied to heal a casing leak about 7544 ft in the Utica shale in a two resin squeeze job at 37.9 and 58.6 MPa respectively (Zhu et al., 2021).

Another thermosetting resin system, Thermaset has been tested with evidence of better performance than class G Portland cement. It has a higher compressive, tensile and flexural strengths than Class G Portland

Table 7
Summary of studies on the impact of curing temperature and materials composition on shrinkage and compressive strength of geopolymers plugs.

Geopolymer material	Curing Temperature, F	Curing time, Days	Compressive Strength, Psi	Shrinkage, %	References
Class F fly ash	170	7	3330	–	(Liu et al., 2017)
Fly ash with nano-scales silica,	248	1	1532.06	–	Ridha and Yerikania (2015)
Class F fly ash	150	1	1500	0	(Salehi et al., 2016)
		7	3300	1.7	
		14	6400	1.8	
Class C fly ash	188.6	1	4641.2	1.6	(Mahmoud et al., 2014)
		3	5656.5		
		7	5946.6		
Class C fly ash	257	1	4206	2.0	
		3	7396.9		
		7	8122.1		
Class F fly ash	122	1	–	0.1	Olvera et al. (2019)
		3	–	0.18	
		5	–	0.21	

Table 8
Impact of activator concentration and aggressive substances on geopolymers.

Experiment summary	Curing condition	Key findings	References
Fly ash based geopolymer studied under sub and supercritical CO_2 pressures (confining pressures: 2030–3770 psi, injection pressures: 870–2900 psi) with 0, 8 and 15% of slag were added to study their effect on CO_2 permeability.	8 M Na_2SiO_3 and NaOH, ratio 2.5 cured at 50 °C for 24 h	2×10^{-21} to 6×10^{-20} m^2 permeability to CO_2. Perameability decreased with increasing injection pressure and slag content reaching 10 times lower values in samples with 15% slag	(Nasvi et al., 2013; Nasvi et al., 2013a,b; Nasvi et al., 2014)
Metakaolin-based geopolymer was placed in a CO_2vessel at 194 °F and 4000 psi for 15 days after which a microstructural analysis was conducted on the sample	Cured for 3 days	The geopolymer exhibited fantastic mechanical properties, with the microstructural analysis showing no significant degradation	Barlet-Gouedard et al. (2010)
A. Geopolymer samples made of **low Calcium fly ash (ASTM Class F)** tested in a CO_2chamber at a pressure of 3 MPa for up to 6 months B. Two geopolymer systems were prepared by alkali activation of **fly ash and kaolin** at room temperature of 20–25 °C with alkaline silicate solutions. Both geopolymer systems were contaminated by the various salts, KCl, K_2CO_3, $CaCl_2$, $CaCO_3$, $Ca(OH)_2$, $MgCl_2 \cdot 6H_2O$, and $Mg(OH)_2$ and had control samples that were free of the inorganic salt contaminants. compressive strength, XRD and FTIR were collected at the sample age of 7, 21, 90, 180 and 270 days.	A. 10 M NaOH and Na_2SiO_3 at a Na_2SiO_3/NaOH ratio of 2.5. Cured at 50 °C. for 24 h B. System I used 15 M KOH solution while System II used 20 M KOH solution.	A. Slight decrease in compressive strength between the 2nd and 4th months and then increased towards 6 months, reaching a slightly higher co mpressive strength value after 6 months. Fairly constant young's modulus at 6months and no significant variation in micro structure B. Chloride salts contamination encouraged early development of strength in system 1 geopolymer reaching 44 MPa in 7 days within presence of KCl but at the 9 months the strength was 20 MPa lower. The carbonate salts prevented hydrolytic attacks on the gels.	(Nasvi et al., 2016)
A **Fly ash and silica fume geopolymer system** was immersed in hydrochloric acid and hydrofluoric acid at 149 °F for 24 h. And a durability study of geopolymer to low (2%) and high (10%) sulphuric acid concentrations was conducted.	Cured at 248 °F and 4000 psi for 24 h	About 1.76% strength reduction was observed after immersion in the acid. An increase in sulphuric acid concentration increased strength degradation in the geopolymer system.	(Lee and Van Deventer, 2002; Nasvi et al., 2014; Giasuddin et al., 2013)
A Class C fly ash based geopolymer was observed for 7 days to study impact of NaOH concentration (varied from 6 M, 8 M and 10 M) temperature on the strength of the class C fly ash geopolymer.	Combination of NaOH and Na_2SiO_3 solutions	For samples cured at 188 °F, the strength of the materials increased with increasing concentration of NaOH through the 7 days period while samples cured at 257 °F recorded higher strengths for the 8 and 10 M samples on the first day.	(Ridha and Yerikania, 2015; Sugumaran, 2015)
An aplite rock with a commercial micro silica (Grade 955 and a commercial Ground Granulated Blast Furnace Slag, GGBFS, "Merit 5000" additive. The resulting geopolymer was exposed to 38 API crude oil, artificial seawater and 0.5% H_2S dissolved in the artificial seawater at a temperature of 100 °C and a pressure of 50 MPa except for the H_2S in brine experiments where pressure was kept at 1 MPa [145 psi] for safety reasons. The samples were observed at intervals of 1, 3, 6 and 12 months.	8 M NaOH alkali solution	The compressive strength and tensile strength of specimens exposed to crude oil and brine was observed to have increased while they retained a low permeability after 12 months. However, specimens in the brine/H_2S mix experienced significant degradation and volume changes that made permeability measurements at the end of 12 months impossible.	Khalifeh et al. (2017)

cement. Its approximately 60 times higher tensile strength and about 5 times higher flexural strengths significantly improves performance in zones of varying loads (Skjeldestad, 2012). This material has been tested for both permeability and long term stability under reservoir conditions by SINTEF. The mechanical strength of the material remains above fifty percent of initial values with low permeability at the end of the aging test (Wellcem, 2011; SINTEF, 2011). A summary of these properties is presented in Table 9.

(Sanabria et al., 2016) reports another field application of a thermal setting resin in a casing leak control operation in Saudi Arabia where a leak on a 7″ casing located at about 6750' was successfully sealed off and the well integrity was restored in an onshore well located in Uthmaniyah Field.

Beharie et al. (2015) treated a thermally activated resin system with CO_2 at 50 MPa and a temperature interval of 100–130 °C for 12 months

Table 9
A summary of the mechanical properties of Thermaset compared to class G Portland cement (Wellcem, 2011; Sanabria et al., 2016).

Properties	ThermaSet	Portland class G cement
Compressive strength (MPa)	77 ± 5	58 ± 4
Flexural strength (MPa)	45 ± 3	10 ± 1
E – Modulus (MPa)	2240 ± 70	3700 ± 600
Rupture Elongation (%)	3.5	0.01
Failure flexural strain (%)	1.9 ± 0.2	0.32 ± 0.04

and showed that after this treatment retained good sealing properties indicating a potential usefulness in carbon storage projects. However, exposure to H_2S and crude oil resulted in a loss of strength.

An investigation of Bisphenol A diglycidyl ether resin diluted with Cyclohexane dimethanol diglycidyl ether and cured with Diethyltoluenediamine, an aromatic amine at isothermal temperatures of 80 and 120 °C by (Alkhamis et al., 2019) shows that the curing time is dependent on curing temperature and the developed sealant can withstand up to as 1000 psi of differential pressure and resists loads higher than 22,067 lbf after 24 h of curing.

(Khanna et al., 2018) studied the mechanical properties of an epoxy resin system designed for a successful remedial cement channel plugging job in an injector well drilled in 1998. The thickening time of the epoxy resin was measured in Bearden units of consistency (Bc) with an initial value of 12 Bc that decreased to 4 Bc as temperature increased to 75 °C. Compressive strength development after 4 h was 12,455 psi and increased to 15699 psi at the end of 48 h. Shear bond epoxy resins is affected positively by increasing the epoxy group, hydroxyl group, and sulphur in epoxy resins while the presence of hydroxyl methyl group increases the heat resistance and cross-link density of epoxy resins.

A detailed review of the processes of synthesizing various types of epoxy resins and their industrial applications has been carried out by (Jin et al., 2015; Yang and Yang, 2013; Mohan, 2013). Readers may refer these works for greater insight into other uses of epoxy resins outside the oil and gas industry.

Because they are designed to set at a given temperature, the polymerization reaction that leads to their hardening is inhibited until the specified temperature is reached. This is an advantage in preventing premature setting during pumping or at surface. Another possibility that comes with this group is their potential use as a base barrier extending into the reservoir and upwards into the casing shoe in a combination barrier system.

The interaction of epoxy resins with reservoir fluids and their hardening mechanism is well studied in published literature as shown in the paragraphs above. This could potentially challenge the traditional process of plug and abandonment of wells. However, studies in this possible combination are scarcely available.

2. Acid-Triggered Resol Phenol-Formaldehyde Resin

The acid-triggered resol phenol-formaldehyde resin a product of methanol-released formaldehyde, polyacrylamide and resorcinol developed through a polycondensation process in an acidic medium (Li, D. et al., 2016).

The mechanism of the development of a seal in the presence of CO_2 and brine is summarized in the following stages: (1) CO_2 and brine reacts to produce H_2CO_3, the acidic medium required for gel development. (2) At high temperatures, methenamine in acidic brine is released (3) Methanol and resorcinol can produce multihydroxymethyl resorcinol, which initiates the formation of phenolic resin polycondensation (4) Further polycondensation leads to larger linear polymer and increases the strength and stability of the gel (Li et al., 2016). The resulting structure shows a lower compressive strength than epoxy resins and significantly affect by temperature, salinity and pH. A study by Li et al. (2016) found that this resin system had a low efficiency of about 31% to CO_2, a factor that further limits its application as permanent barrier.

Further studies to improve its sealing capacity could be aimed at investigating the properties developed in acid mediums different from H_2CO_3, use of alternative hardeners and the application of nano particles for increased mechanical strength and decrease in permeability.

A third group of resins with sealing characteristics is the Double Network Water-Absorbent resin – a polymer cross-linked with a resin system that contains two independently cross-linked networks (Na et al., 2004).

This group of resins is made up of a rigid polyelectrolyte and a flexible neutral polymer. The former increases the system's ability to withstand mechanical stress while the later helps it relax stress. Their compressive strength can reach 20 times the strength of single network resins (Lai et al., 2010). In addition to this, they are not sensitive to pH and salinity and are chemically stable (Luzardo et al., 2015).

Their sealing mechanism involves properties of swelling, deformability, and absorbability. Under reservoir conditions, hydrophilic groups on the polymer chains absorbs formation water, swells and plugs the formation with a swelling ratio of 5–10 time according to (Lai et al., 2010) to establish a high-quality seal.

Additional studies on the properties of polymer resins include: (Todd et al., 2018; Alsaihati et al., 2017), rheological behaviour (Sanabria et al., 2016; Vicente Perez et al., 2017), density flexibility for applications in zones of narrow pressure gradient margins, resistance to contamination (Elyas et al., 2018), mechanical strength and resistance to strain (Genedy et al., 2017; Bertram et al., 2018), bond quality, long term thermal stability. Refer to Table 10 for a summary of experimental studies on polymer resins.

It is obvious from Table 10 that increase in temperature accelerates the gelation time of resin, resins are stable to CO_2 attack but could be damaged in the presence of high H_2S concentrations to points that affect their performance as well barrier elements. However, they develop sufficient compressive strength within a short period of their hardening to qualify as permanent well barriers.

Because they are designed to set under specific conditions of temperature or contact with certain polymerization initiator, their hardening is inhibited until these conditions are met. This helps prevent premature setting during pumping or at surface. This property opens an opportunity for designing systems that fit specific reservoir conditions and the development of a barrier system that extends into the reservoir, sets in the reservoir, and extend into the wellbore casing to provide a base for a combination barrier.

2.4. Metal alloys and in situ barriers as permanent plug and abandonment materials

Bismuth possesses special properties that has encouraged its use in well plugging and abandonment operations (Carragher and Fulks, 2018).

- Relatively low melting point (273 °C) compared with other metals
- Viscosity very similar to water when in liquid form
- High density, with a specific gravity of 10
- Noncorrosive and nontoxic and unaffected by CO_2 and H_2S
- Reaches about 2–3 percent expansion when it solidifies
- Eutectic metal, converting from liquid to solid instantaneously without going through the gel phase.

Metal alloys have high densities and therefore require a base anchor for the deployment. The metal alloys are designed to have higher melting points above the highest anticipated temperature along the wellbore. As the metal alloys have very high densities, the liquid metal requires a foundation as a base. The alloy is designed in a way that it has a melting temperature which is higher than the maximum anticipated well temperature. The common method of bismuth-based alloy placement involves the lowering the solid material downhole and melting at

Table 10
Summary of key experiments on the impact of reservoir conditions on polymer resin plugs.

Experiment summary	Key Findings	References
Thermally activated resin system was treated with CO_2 at 50 MPa and a temperature interval of 100–130 °C for 12 months with exposure to H_2S and crude oil	Good quality sealing property was retained at the end of CO_2 treatment, but properties worsened on exposure to H_2S	(Beharie et al., 2015)
A thermally activated Bisphenol A diglycidyl ether resin was diluted with Cyclohexane dimethanol diglycidyl ether and cured with Diethyltoluenediamine, at isothermal temperatures of 80 and 120 °C and cured for 24 h of curing	The developed sealant withstood up to as 1000 psi of differential pressure and resists loads higher than 22,067 lbf after 24 h	(Alkhamis et al., 2019)
Modified polyacrylamide (PAM) with an average molecular weight (MW) over 3×10^6 Methenamine MW 140.9, resorcinol, MW 110.1, $CaCl_2$ and CO_2, NaCl and deionized water were used in experiments, to prepare a H_2CO_3 triggered resin in transparent tubes with a pressure tolerance up to 1.5 MPa at temperatures between 50 and 80 °C.	The gelation time was shortened with an increase in temperature (50–80 °C) and a gel with a strength code H was developed-Slightly deformable nonflowing gel	Li et al. (2016)
A unidirectional carbon fiber/epoxy resin with a nominal size of 60 × 20 × 0.01 mm was heated in an oven EDG3000-EDGCON3P to 121 °C at 2 °C/min heating rate and maintained at this final temperature for 90 min then cooled to ambient temperature and exposed to aqueous solution of the following inorganic salts: (NaCl), (Na_2SO_4), (KCl), ($NaHCO_3$), (KBr), (NaF) and (H_3BO_3) and their vapour. The desiccators containing the samples remained in the oven under temperatures of 40, 60 and 80°C for periods of 7, 14, 21 and 28 days.	The immersed samples at 40 and 60 °C and the vapour treated samples presented a gain in weight, however the sample immersed at 80°C experienced a weight loss indicating a degradation of the polymeric matrix.	Soares-Pozzi and Dibbern-Brunelli (2016)
Silane solutions with a pH value 10.6 and 4.6 (acidified with formic acid) was used to study their impact on the shear bond between Poly (bisphenol A-co-epichlorohydrin), glycidyl end-capped (DGEBA) based epoxy resin with Cold roll steel plates of E24 series.	The pipe- resin joints pre-treated with pH 10.6 had better durability than joints pre-treated at pH 4.6. At 10.6 cross bridges were formed at the silane/epoxy interface while at 4.6, the formic acid attacks amino groups of the silane groups and consequently decreased the reaction of epoxy with amino acids.	Tchoquessi Doidjo et al. (2013)

desired depth. However, there is a less commonly used method that involves lowering the material in liquid form in a container. The container is then opened at desired depth to alloy the molten alloy exit and develop the desired plug. (Bosma et al., 2010; Abdelal et al., 2015).

The practical use of bismuth as a plug and abandonment material was challenged by high energy requirements (480 V and 11 A to generate 540 kJ of energy) for melting it and the process of deploying such amount of energy downhole (Carpenter, 2019; Khalifeh and Saasen, 2020). This has been pretty much overcome with the use of thermite (a mixture of aluminium and iron oxides that reacts to generate significant amount heat) as an energy source for downhole melting of bismuth as described by (Carragher and Fulks, 2018).

The bismuth plug assembly is made up of 4 major components: ignition system, alloy jacket, inner tube, which contains the heat source, thermite and skirt. The heat generated through the thermite reaction melts the bismuth alloy jacket which is supported by the skirt as it solidifies. The arrangement of these components is illustrated in.

(Carragher and Fulks, 2018) provide a detailed description of the deployment process of bismuth as a well barrier on electric line using a modified thermite as heat source. The following paragraphs summarizes the main points of the process.

In order to obtain the necessary energy, the idea of thermite was introduced as a heating element.

A chemical reaction occurs between the components of thermite resulting in the production of aluminium oxide, iron and large amounts of heat energy. The generated heat from this process exceeds 10,000 kJ. However, the reaction trigger temperature is also more than 2000 °C which can have significant negative impact of casing pipes and cement behind casing.

To overcome this challenge, binding and damping agents are required to ensure a consistent chemical composition of iron oxide and aluminium and to control the rate of reaction and amount of heat generated respectively. A thermite mixes that could burn between 200 and 800 °C within 15–45 s were developed. A starter heater that could be run on standard electric lines was used to initiate the chemical reaction. The heater required 240 V and 60 mA for 15 s to generate sufficient heat to trigger the chemical reaction. The temperature of wellbore fluids, which acts as a cooling agent for the bismuth affect the rate of bismuth solidification. To gain more control over this process, bismuth alloys were developed through addition of small amounts of other metals. This reduced the melting point of bismuth from 273 °C to between 93 °C and 263 °C.

The use of these bismuth alloys with modified thermite heaters has now been used to create gas tight seals in a range of wellbores with temperatures between 4 °C and 150 °C. Once the chemical reaction is triggered, the bismuth alloy melts from top and flows down into solidifies at the base as it is cooled by the wellbore fluid taking the shape of the area as it expands to create a seal. This expansion creates a metal-to-metal seal and provides sufficient friction bond to keep the plug in place without the development of any chemical bonding between the casing and plug (see Fig. 12).

Results of inflow tests conducted to compare the sealing quality of bismuth thermite plug and Portland cement/bridge plug combination as permanent well barriers is represented in Fig. 13. The deployment of bismuth tool in two wells in the Norwegian sector of the North Sea provided a sealing solution in wells where a bridge plug/cement combination had failed. The wells continued to bubble gas up the tubing and build surface pressure up to 1200 psi but showed no pressure or bubbles at surface after bismuth plug deployment and testing pressure testing up to 4000 psi.

A bismuth-tin alloy (BiSn) containing 58-wt% bismuth (Bi) and 42-wt% tin (Sn) was studied by (Zhang et al., 2020) as an alternative to Portland cement for plug and abandonment of offshore oil and gas wells showed that the molten alloy has no affinity to limestone surfaces in a sliding experiment. A diagram representing the outcome of this experiment is shown in Fig. 14.

The authors proposed 2 separate approaches to improve bond quality between the alloys and formations along the wellbore to prevent plug displacements and ensure long term integrity. While alloy intrusion is recommended for porous formation, a milling treatment to create a degree of imperfection on tight formation surface prior to plug placement is recommended. As the alloy transitions into the solid state, it expands and fills these imperfections to enhance bond strength.

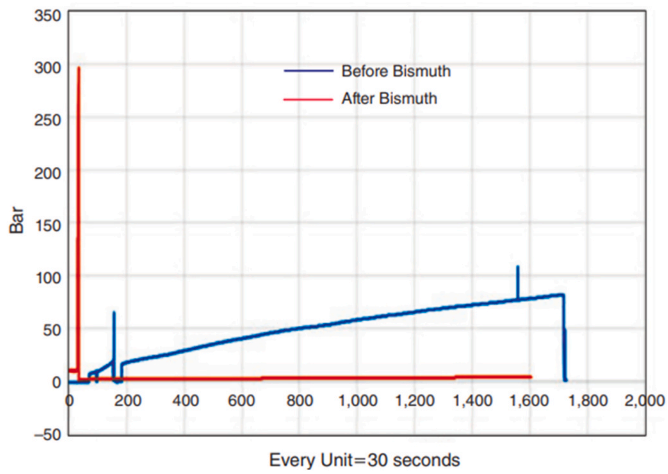


Fig. 13. Comparison of bismuth plug leak test against bridge plug/cement combination (Carragher and Fulks, 2018).

This technology has now been deployed in oil fields in the North Sea and the United States and continues to gain popularity with increasing success where cement and bridge plugs fail. For additional field application reports, readers may refer to (Zhang et al., 2021; Thorstensen et al., 2022; Carragher and Fulks, 2018; Zhang et al., 2022; Pena and de Lemos, 2021).

Bismuth alloys have proven high performance in wells, however, data on their long-term performance and durability is scarce. Although wellbore fluid plays the role of heat removal, the possibility thermal stress development in cement behind casing cannot be eliminated during this process. In addition to these, this process depends on friction bonding between two metals of differing stability to downhole corrosive agents and conditions. A deterioration of the casing pipe over time through corrosion can result in failure of the barrier system.

Some applications of bismuth alloys aim at melting both the casing, cement behind casing and sections of the formation to form a seal that spreads across the wellbore and into the formation on solidification (Darmawan, 2021). This class of well barriers is referred to as modified in situ barrier and illustrated in Fig. 15.

Thermite is the choice material for heat generation in this process. A mechanical plug base with a layer of sand covering provides the foundation of the molten materials. In this combination, the sand serves the protects the plug form the high temperatures generated during the exothermic reaction of thermite.

The following factors affect the acceptance of this process for permanent plug and abandonment of wells.

- Limited cost and functionality data
- The presence of metals and cement in the mix raises questions about eternal durability (Aslani et al., 2022)
- The possibility of damage initiation on the exiting well infrastructure above the and below the sealing point needs further investigation especially in wells with multiple productive formations

Other materials that have been studied as potential barriers for permanent plug and abandonment of wells include bentonite, (Towler et al., 2008, 2016), blast furnace slag, spacers (Ma et al., 2018), quick clays and unconsolidated plugging materials such as sandaband (Saasen et al., 2011).

Alkali-activated slag (AAS) materials has been studied extensively as a possible alternative to cement in construction. However, studies on the use of this materials in oil and gas applications is limited. It possesses similar advantages with fly ash geopolymers (Pacheco-Torgal et al., 2008; Bakharev et al., 2001). However, research also shows that AAS shrinks more than Portland cement and requires fibre-based additives to overcome this weakness (Collins and Sanjayan, 2000). These alternative materials as still undergoing trials and mostly not recognized as permanent plugs in isolation under most P and A regulations.

2.5. Self-healing cementitious materials

The ability of cement to recover after damage initiation has been studied extensively in the construction industry. This process is a result of one of the following two broad process groups: precipitation of calcium carbonate $CaCO_3$ and hydration of anhydrous cement in the microstructure of the set concrete material (Neville, 2002).

The self-healing of concrete after up to 50% loss of initial relative dynamic modulus during freeze/thaw cycling during subsequent storage in water was reported by (Jacobsen and Sellevold, 1995; Jacobsen and Sellevold, 1996). Self-healing of cracks in cement arising from calcite formation as water flowed through the cracks was studied in an experiment by (Edvardsen, 1999).

In addition to the presence of water (Reinhardt and Jooss, 2003), identified temperature and crack width, as additional factors affecting self-healing abilities of concrete.

Water is an essential requirement every healing mechanism identified above. It becomes a problem in situations like oil and gas wells where cracks might be exposed to other substances instead of water (Termkhajornkit et al., 2009). This necessitates the design of well specific cement for application in oil drilling and well abandonment.

In drilling and well plugging and abandonment, the goal of barriers is to provide long term zonal isolation. The development of cracks on well barriers that do not selfheal could potentially develop to major leakage pathways and integrity failure.

Self-healing cementitious materials are designed to intrinsically recover after exposure to certain degrees of failure initiation. This can be achieved with help of materials in the cementitious material that are activated by contact with wellbore fluids whenever cracks or deformities are initiated in the sheath. They are designed to either swell or react and generate an impermeable biproduct when contact is made with wellbore fluids. These seals off the developing crack and restores integrity (Roy-Delage et al., 2000; Cavanagh et al., 2007).

(Cavanagh et al., 2007) reports successful field trials of a self-healing cement system in Alberta, Canada in a field where SCVF was a common challenge. According to their study, the well integrity was restored with no sign of gas build-up of SCVF after a 6-month period.

The system was lab tested and retained its self-healing properties in the presence of both oil and gas. However, the study does not present any evidence of self-healing of the system in the presence of brine or

(a) (b) (c) (d)

Fig. 14. Illustration of the non-wetting characteristics of molten BiSn alloy on preheated limestone surface (a - molten alloy on flat rock surface; b -d, molten alloy on increasinly tilted rock surface . Adapted from (Zhang et al., 2020).

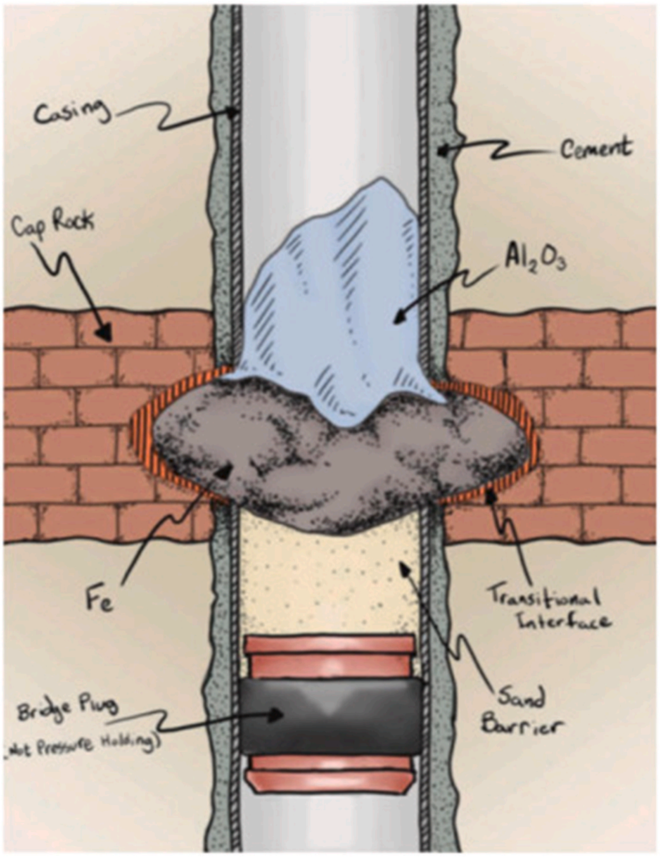


Fig. 15. Illustration of in situ modified materials as a permanent well barrier (Aslani et al., 2022).

brine/aggressive gas mixtures, a situation often encountered in depleted reservoirs.

The self-healing properties of a cement system (a copolymer cement with chemical additives including deformer, retarder, filtrate and drag reducers and ethylene-vinyl acetate) was studied by (Yuan et al., 2017). Ethylene-vinyl acetate, EVA, was used at fractions of 0–6 percent at a 2% increment.

EVA provided the self-healing property given that its particles could melt at high temperatures. As they melt, the liquid flows from the cement matrix. On contact with aqueous and alkaline environments, EVA expands and blocks the micro-annuli and cracks to maintain well integrity. The study also indicates an increased interfacial bonding in the EVA cement system and improved self-healing of the system at operating temperatures greater than 110 °C. Flexiblle expanding cement systems have shown better chemical expansion but a lower compressive strength and Young's modulus in orders of about 40–70 percent (Williams et al., 2011). While these values are acceptable for most well conditions, a major limitation to the use of these cement systems is their cost and late compressive strength development (De Andrade and Sangesland, 2016).

The ability of well barriers to recover from stress or thermal induced cracks will define their long-term performance as permanent plugs. Swelling materials such as sodium polyacrylate and poly (acrylamide-*co*-acrylic acid) potassium salt (Mahon et al., 2020) could be evaluated as additives to cement mixtures for plug and abandonment of wells to increase interfacial bonds and enhance positional stability after hardening.

3. Materials failures and condition monitoring

Well barrier failures and integrity loss in producing and abandoned wells could occur because of chemical attack on barrier materials, mechanical failures, interfacial debonding of barriers from surrounding materials or formation, contamination by drilling fluids.

Given that cement is the most common barrier material for plug and abandonment, attempts have been made to either design tougher cements that will be able to withstand downhole stresses using various additives. A more recent direction for long term integrity focuses on design of cement sheaths with self-healing properties (Cavanagh et al., 2007). The factors leading to barrier failures arise from pressure and temperature variations during production and the impact of operational interventions such as pressure testing, hydraulic fracturing and thermal cyclic loading (Goodwin and Crook, 1992; Kiran et al., 2017; Bois et al., 2011; Li et al., 2006). Additional works on temperature If these are not detected and addressed prior to or during Plug and abandonment operation, these barrier failures during production can become the principal reason for integrity failure in abandoned wells (OGUK, 2015a, 2015b, 2015c). identifies the three broad categories of failure modes in permanent barrier materials. These include positional shift of the barrier material, leakage through and around the barrier material. A permanent plug is placed according to regulations and expected to remain at its designed depth. This is affected by the nature and strength of the bonds developed between the plug and its surrounding. Bonding could be chemical, physical. In addition to interfacial bonding the intermolecular bonding of a barrier material affects its stability of disintegration under reservoir conditions and could consequently have an impact its positional stability.

Leakage in abandoned wells can occur through any of the paths identified in Fig. 4. This could be around materials, that is through interfacial contacts or through the bulk material. For this to occur the following conditions must be present: (1) a fluid source (2) a driving force and (3) a leakage path (Watson and Bachu, 2009). The leakage path could be through cement plug body; cement plug/casing interface, corroded or perforated casing body, cement sheath/casing interface, cracks and fractures in the cement sheath or cement sheath/formation interface (Bujok et al., 2013; Ford et al., 2017; Obodozie et al., 2016).

Leakage through the bulk barrier material in abandoned wells occurs through permeation; a time dependent a process which follows either fluid flow or diffusion (OGUK, 2015a, 2015b, 2015c). The nature of barrier material, length of barrier and the differences in pressure or fluid concentrations at opposite ends of the plug determine affect the time taken for a fluid breakthrough from the plug (Nagelhout et al., 2010, van Eijden et al., 2017).

Development of micro annuli at the interfacial points between permanent plugs and their surrounding casing or formation has been identified as a major mode of failure contributing significantly to leakage from abandoned wells by (Lecampion et al., 2011; Bois et al., 2011; Ford et al., 2017). Flow through the bulk cement sheath can be attributed to poor slurry design, poor cement placement practices and contamination that results in channels through the cement and poor mechanical properties in of the hardened cement plug (Thiercelin et al., 2006).

(Ford et al., 2017) Studied the effect of plug length and its reduction of rate of leakage. The outcome of this study is shown in Fig. 16 and indicates up to 60 percent increase in leakage rate when the plug length is halved from 200 m to 100 m.

Studies to understand the integrity cement plug/formation interfacial bond include experimental study and a model developed by (Ladva et al., 2005; Wang and Taleghani, 2014). (Wang and Taleghani, 2014) developed a three-dimensional numerical model to study the interfacial debonding initiation and propagation pressure of cement sheath/formation. The authors discovered that higher values of cohesive interfacial strength, or cement rigidity could effectively reduce the possibility of well barrier failure.

(Feng et al., 2017) developed a 3D finite-element model to study fluid-driven interfacial debonding in an injector well, using the coupled pore pressure. This study discovered that interfacial debonding fracture is propagated vertically along the path of initial defect rather than

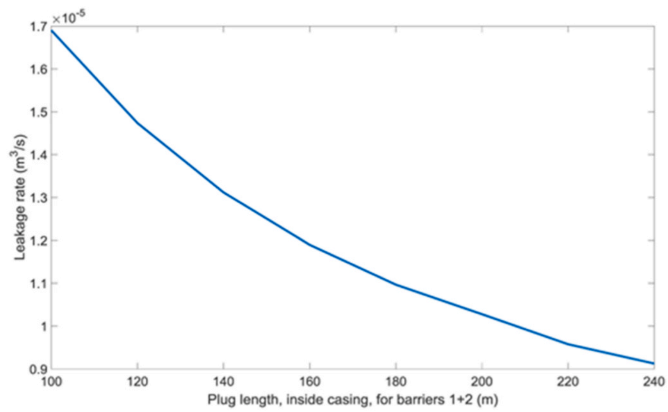


Fig. 16. Relationship between plug length and rate of leakage (Ford et al., 2017).

azimuthally. In addition to this, the study also revealed that cement stiffness, interface critical strength, and toughness affected the debonding propagation. While this study was carried out on injection well, it is important to note that plugs in abandoned wells can be subject to similar situations in cases where a pressure build up occurs in the reservoir post abandonment. This also points to the need for complete isolation of existing well infrastructure from the reservoir during plug and abandonment. Faults in existing well barrier structure could become weak points and form paths of least resistance for fluid leakage to surface.

(Cheng et al., 2017) developed a reservoir-geomechanical coupling model to predict the effects of variations of temperature, in-situ stress, pore pressure on cement sheath/formation interfacial bond post abandonment. The authors discovered through calculations that tensile failure was the main failure mechanism in cement sheaths. The risk of failure is reduced in cement plugs of lower elastic modulus.

(Jiang et al., 2020) developed a 3D numerical model to study the fracture debonding process of cement plug/casing, cement plug/formation system based on the cohesive zone method. The studied quantified the relationships between the fracture debonding height and fluid migration time and, the impact of horizontal in-situ stress, mechanical properties of the cement plug, and interfacial characteristics on the fracture debonding height. The outcome of their research can be seen in Fig. 17. Increase in the value of interfacial critical shear strength leads to a decrease in cement plug/casing interfacial fracture debonding height. This signifies that an increase in the interfacial critical shear strength

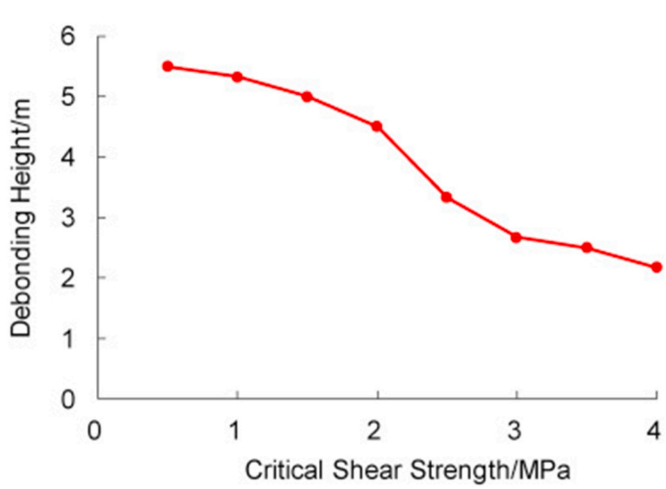


Fig. 17. Dependency of fracture debonding height of cement plug/casing interface under varying critical interfacial shear strength (Jiang et al., 2020).

reduces lowers the risk of debonding failure.

In addition to the above factors, chemical degradation, plug shrinkage on hardening, differential thermal expansion, formation creep are additional mechanisms that lead to plug failures in abandoned wells (OGUK, 2015a, 2015b, 2015c).

Investigation of the state of post decommissioning monitoring reveals that the state of Texas has developed a regulatory requirement for monitoring of abandoned wells. A summary of its requirements includes the following:

- 24-h continuous-in-time measurement at least three days after the plugging date.
- A second continuous-in-time measurement in the second or third month post-plugging.
- One point-in-time measurement at least six days before or after the continuous-in-time measurements.
- An additional methane assessment is required approximately five years after plugging, which can be done with a handheld sensor or multi-gas sensor with a lower detection.
- If methane concentrations in excess of 3 ppmv are detected and confirmed during the test, additional sets of measurements are required until methane emission rates are stabilized. (Wei, 2022).

It is important to note that this system targets methane emission on the surface around the wellbore. It fails to account for possible inter reservoir flow and potential ground water pollution that could be happening underground. This leaves questions about how permanently sealed wells abandoned following existing regulations are (Trudel et al., 2019). question the concept of permanent plug and abandonment and attempts to open a conversation on the potential for non-permanent bridge plugs in combination with regular monitoring instead of a permanent plug that is not monitored for failures. Long-term implementation of this concept will be both expensive and potentially impracticable. In addition to the logistics challenges and costs, such an approach will detect failures in form of flow but fails to prevent it.

The development in AI and Machine learning could be vital to the P and A industry. Implemented in combination with permanent plugs or temporary plugs, such systems might be able to predict failures and recommend remedial operations for preventive maintenance for commonly used P and A materials. Such insights will be relevant for improved materials selections and materials reengineering to ensure long term integrity.

4. From liabilities to assets – plugging for CO_2 and H_2 storage

The repurposing of depleted oil and gas reservoirs has become a subject for discussion in literature and public domain. As the drive towards net zero and efforts to control global warming continues, depleted oil and gas reservoirs and non-productive wells are being considered for CO_2 and H_2 storage.

The idea of storing CO_2 in depleted reservoirs requires that the formation be able to hold the gas in supercritical state or in solution and prevent return to the atmosphere (Zhang and Bachu, 2011). On the other hand, hydrogen is stored temporarily for reuse.

However, the possibility of leakage into the atmosphere remains a major challenge limiting the use of depleted reservoirs for this purpose given the significant number of well integrity issues reported in literature. Readers may refer to (Davies et al., 2014) for statistics on well integrity issues and Fig. 4 for potential leakage pathways from abandoned wells. These pathways and other natural pathways such as faults (active or reactivated), open fractures, interruptions and breaches through the cap rocks can lead to gas leakage back into the atmosphere from storage reservoirs (Watson and Bachu, 2009; Kopp et al., 2010; IPCC, 2005).

The success of any CO_2 storage in geological formations is dependent on three condiitions: (1) the formation must have capacity that is porosity, (2) Possess injectivity or permeability, and (3) confinement that is able to maintain long term integrity (Kopp et al., 2010; Bachu, 2010; Metz et al., 2005).

Wellbore integrity has been defined as a condition that maintains isolation of geological formations and prevents vertical migration of fluids by (Crow et al., 2010). Wells are considered to have integrity if they meet the following conditions:

the well is pressure tight, that is no significant leakage is observed in the casing, tubing, or packer and

there is no significant interzonal fluid movement leading to pressure charging of reservoirs or contamination of underground water. (Bai et al., 2015).

Well integrity assessment methods have evolved over the years and can now be performed with a high degree of confidence (Schütze et al., 2012; Reinicke and Fichter, 2010). However, even in situations where well integrity has been established at the end of the well's productive life, concerns remain over the long-term interaction of CO_2 with wellbore cement and casing materials which could degrade over time and compromise integrity (Krilov et al., 2000; Jacquemet et al., 2005). A summary of experimental findings on the impact of aggressive media on cement is presented in Table 5. However, analysis of cement cores from a wells in Texas and Colorado that had been exposed to CO_2 for 30 years at reservoir conditions suggest that Portland cement based wells can prevent significant migration of CO_2 from reservoirs for long period of time if properly completed and abandoned (Carey et al., 2007). These findings were further examined through simulations conducted by Xiao et al., 2017 which concludes that Portland cement retains its very low permeability over long periods of interaction with CO_2. This study further suggests that after 100 years interaction period between cement and brine CO_2 mixture, the porosity or Portland cement could decrease from 30% to 20%, which provides a protection for the cement from further CO_2 penetration. This simulation result is similar to the findings of (Crow et al., 2010) who studied the impact of CO_2 on a class H Portland cement mixed with 50 percent fly ash and 3 percent bentonite gel after 30 years exposure to CO_2 in a natural producer of the gas drilled In Dakota formation. Although, evidence of deterioration was significantly evident in core samples taken close to carbon dioxide producing formation, cement core samples taken high up the annulus showed much decreased sign of interaction with the corrosive gas and hence the well retained its integrity over its 20-year production life after initial 10 years delay after drilling. The process governing these observation has been described in literature as self-healing of cement initiated by carbonation, a reaction in which the CO_2 brine mixture reacts with $Ca(OH)_2$, portlandite to form calcite, $CaCO_2$. This process leads to increase in mechanical strength, decrease in porosity and permeability. However, it is important to note that the effectiveness of this self-healing process assumes that transport of CO_2 through the cement matrix is a diffusion-controlled process. Where significant fractures exist in the cement and a significant pressure differential that enables flow, a combination of leaching and fracture expansion as a result of calcite crystallization stress could occur which ultimately compromises integrity and could lead to leakage of the stored gas to the atmosphere. Questions remain about longevity especially because abandoned wells are expected to retain integrity forever.

The in-situ conditions affecting the carbonation of cement in CO_2 storage wells include the temperature, pressure, reservoir rock type, formation water composition, the CO_2 state (phase), and fluid flow rate. CO_2 storage depths is recommended to be more than 800 m. At such depths, pressures and temperatures are in the orders of more than 7.38 MPa and more than 31 °C respectively. Formation water at injection depth is required by regulation to possess greater salinity than the protected underground water (Metz et al., 2005; Koplos et al., 2010; Pruess and Müller, 2009) identified 4 possible scenarios in supercritical CO_2 storage in deep saline aquifers and hydrocarbon reservoirs: (1) dry supercritical CO_2 near the injection well); (2) a wet supercritical CO_2 also known as CO_2 (3) CO_2-rich water whose composition varies with the proximity to the CO_2 plume; and (4) original saline water containing negligible amount of dissolved CO_2 The most important scenarios in the study of cement in wells with zonal communication to a CO_2 storage reservoir are: the interaction between cement and wet supercritical CO_2 and the interaction between cement and CO_2 saturated formation water which follow initial contact between the wells and formation water (Zhang and Bachu, 2011).

Factors affecting in situ CO_2 solubility in water include pressure, temperature, and formation water salinity. The dependence of solubility on these factors is well studied in published literature. (Enick and Klara, 1990; Spycher and Pruess, 2005). This dissolution process reduces the pH of formation water. The acidified formation water could degrade wellbore barrier materials such as cement and casing (Carey et al., 2007; Scherer and Huet, 2009).

(Prevedel et al., 2014) discussed lessons learnt from pilot project on a CO_2 storage in abandoned wells. The plug cementation of the Ketzin 202 well was carried out using CO_2 resistant cement. a total of 67 kilotons of CO_2 were safely injected into the sandstone units of the Upper Triassic Stuttgart Formation in a depth between 630 and 650 m prior to commencing the abandonment operations on the selected field. The studied well which had 53 bars of pressure at the well head before the commencement of the abandonment operation recorded no indication of pressure after a two-day coring period of the plug cement.

(Alani and Okechukwu, 2019) examined the potential use of reservoirs for underground storage of natural gas. The authors classified the factors affecting effective use of reservoirs or for gas storage as both geological and geographical. The geological factors define the properties of the formation and the caprock quality while geographical factors relate to the location of the field and its proximity to useable gas transport infrastructure. Given that hydrogen is stored for reuse, studies in underground storage of natural gas can be adapted to hydrogen with special attention to the differences in physical and chemical properties of the gases which determine their reactivity with wellbore materials and transport lines.

Studies on large scale storage of hydrogen for energy generation can be traced back to the 1970s when (Foh et al., 1979) performed a technical investigation of hydrogen properties and discovered that hydrogen embrittlement as the only factor limiting its underground storage. Other authors have researched and reported underground storage of hydrogen in different countries, (Lin and Wei, 2010a; An, 2012; Ge and Liu, 2012; Lin and Wei, 2010b). Mechanisms that could affect integrity in underground hydrogen storages include microbial corrosion, hydrogen blistering induced cracking and hydrogen embrittlement, failure of well barrier materials, and caprock failure (Ugarte and Salehi, 2022).

(Singh, 2022) studied the potential for cyclic hydrogen storage of depleted Haynesville shale laterals. His findings suggest an increase in recovery stored hydrogen as the in time-length of a cycle increase, irrespective of the scale of the injection. However, an increase in injection cycle time length had a negative impact on the purity of recovered hydrogen.

In summary, practical utilization of old wells for gas storage will mostly be slowed by the fact that most wells where not designed for this purpose. The material selection for their construction did not consider their reuse for this purpose and cement job qualities may not be such that eliminates channels in and around the cement sheath matrix. Cement-formation and cement-casing interface bond qualities will play significant role in the usability of wells for CO_2 storage given the possible existence of flow channels along these interfaces. These channels could be a result of poor cement placement, cement shrinkage on transition from slurry to solid phase or a combination of both.

However, more recent wells drilled with higher regulatory demands on integrity could be viable options for CO_2 and hydrogen storage at the end of production. Present and future oil wells should be adapted for this purpose from their design and drilling phases. While this might significantly increase drilling and completion costs, such wells will find usefulness at the end of their hydrocarbon production life and not become liabilities.

5. Conclusion and recommendation for research

Plug and abandonment of oil and gas wells has developed from unregulated to a highly regulated practice in major oil and gas producing countries. While these regulations differ in their requirements of number and length of permanent barriers, they are all designed to achieve zonal isolation and to prevent flow of reservoir fluids into the environment and subsurface water.

Over the years under review, Portland cement has been the industry's primary choice for plug and abandonment of wells. However, a review of existing literature of experiments and field applications suggests that the volumetric shrinkage of Portland cement as it sets and its degradation and consequent failure over long term interaction with reservoir fluids, especially at elevated temperatures and pressure conditions, has contributed significantly to hydrocarbon leakage from abandoned oil and gas wells. Efforts towards permanent zonal isolation by operators and regulators have mainly been in two directions: development of improved cement slurry with the help of various additives and development/investigation of alternative plug and abandonment materials not based on Portland cement.

The addition of nano particles to cement and the development of high-performance self-healing cement slurries are promising directions for improved cement performance and geopolymers, polymer resins, Bismuth alloys and bentonite are being investigated as alternative barrier materials. While resins are solid free and able to flow into pore spaces where solids bridging would make cement penetration impossible, geopolymers have shown better self-healing properties and improved resistance to contamination by oil and synthetic based drilling fluids. Bismuth alloys on their part, are resistant to aggressive media often found in oil and gas reservoirs. Like resins, they can flow into pore spaces in molten form and are able to reach 2 to 3 percent volume expansion on solidification. These properties improve interfacial bonding and zonal isolation.

Well barrier integrity failures could be induced by mechanical, thermal, chemical factors downhole or any combination of these. The current stock of abandoned wells comprises mostly of wells drilled when regulations were not very clear on what happens at the end of a well's productive life. Poor design and choice of drilling and completion materials for this group of wells could have possible contributions to their hydrocarbon leakage rates.

Most research on plug and abandonment have focused on materials improvement and degradation mechanisms and material placement. This has given rise to more resistant materials, but the current practice of plug and abandonment fails to provide total isolation of the possible leakage pathways from reservoir fluids. The old casing and cement behind casing remain exposed to reservoir fluids below the plug which could lead to development of leakage paths many years after abandonment. Refer to Fig. 7.

Frontier research in plug and abandonment of oil wells should be directed towards selection of materials and barrier placement technologies that not only provide permanent isolation of the wellbore but are able to permanently isolate reservoir fluids from existing wellbore infrastructure such as casing and cement behind casing within reasonable budget. Such materials should have good rheology for flow into the reservoir before setting, remain unreactive with reservoir fluids under reservoir conditions, possess exceptional mechanical properties and high resistance to flow thorough interfacial contacts and permeation through the bulk material. This will pave way for the sustainable repurposing of depleted reservoirs for CO_2 and hydrogen storage, hence, transforming old wells from liabilities to assets.

The application of AI and machine learning for failure prediction in barrier materials will improve materials selection for P and A and ensure long term integrity of abandoned wells. Further research in this area will be relevant required for industry readiness as more challenging wells reach cessation of production.

Additionally, as the industry drills deeper and in more challenging environments, the design of future wells and the selection of casing and cementing materials should be for long term integrity and resistance to reservoir fluids.

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.

Data availability

No data was used for the research described in the article.

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