1 Introduction

1.1 Motivations and objectives

The petroleum industry is confronting increasingly scarce shallow and conventional resources, necessitating deeper drilling and operations in more demanding environments. Despite the global emphasis on carbon peaking and neutrality, drilling engineering remains essential and holds promising prospects. As shown in **Figure 1.1**, the application of underground resources and space through drilling techniques has diversified, encompassing activities such as geological exploration, oil and gas recovery, geothermal energy extraction, gas storage, CO_2 storage with enhanced gas recovery (EGR), CO_2-enhanced oil recovery (EOR). However, the challenging subsurface conditions and the growing complexity of development and production techniques have set higher standards for wellbore integrity. For instance, deep unconventional resource extraction involves extreme conditions, including high temperature, high pressure, and significant cyclic loads, as well as high temperature-differential stress caused by hydraulic fracturing, staged fracturing, and large-scale production. Thus, ensuring long-term well integrity throughout the well's lifecycle is increasingly critical.

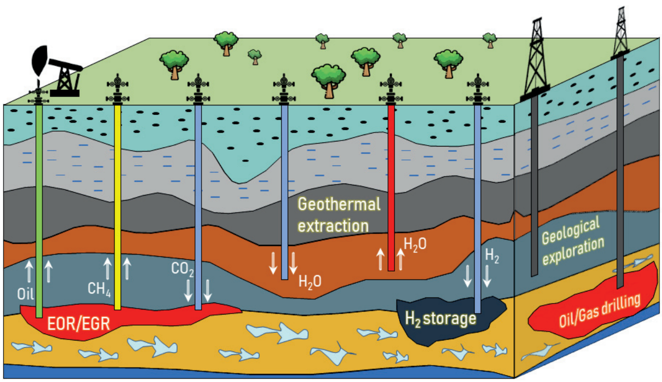

Figure 1.1 Application of underground resources and space through drilling techniques.

The most widely accepted definition of well integrity is provided by NORSOK D-010 (Lysaker, 2013), which defines it as the application of technical, operational and organizational solutions to reduce the risk of uncontrolled release of formation fluids throughout the lifecycle of a well. Effective well integrity requires establishing appropriate barrier isolation to control downhole fluids. The cement sheath, used in oil and gas wells since 1903 (Barnes and Bensted, 2019), serves as the primary barrier to well integrity. After completing each drilling stage and installing the casing, cement slurry is injected into the annulus between the wellbore and casing. Once the cement solidifies, it forms a continuous and durable sheath. The cement sheath provides essential mechanical and hydraulic isolation between the casing and surrounding rock formations.

Improper well cementing practices can result in various issues, including casing damage (Combs et al., 2017), sustained casing pressure (Xi et al., 2020a), harmful gas and liquid leaks (Jackson and Murphey., 1993), and wellhead lift (Arash et al., 2014). These problems can severely compromise well integrity and productivity, potentially leading to well shut-ins. Several notable incidents of oil and gas well blowouts and major leaks have been linked to cement sheath integrity failures worldwide (**Figure 1.2**).

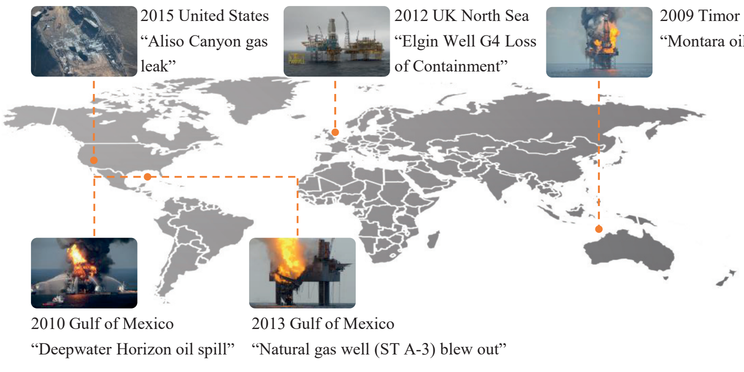

Figure 1.2 Notable incidents related to cement sheath failure. Sources from (BSEE, 2013; Gibson, 2016; Pallardy, 2010; Schuler, 2009; Wikipedia, 2023a).

In 2009, a fluid blowout occurred at the H1 Well on the Montara wellhead platform off the northern coast of Western Australia (Wikipedia, 2023b). A direct and proximate cause of the blowout was the defective installation of a cemented shoe in the 9⅝-inch casing of the H1 Well, which compromised the integrity of the cemented shoe as a barrier (MCI, 2010). The most widely publicized incident is the Deepwater Horizon oil spill (also known as the "BP oil spill") in 2010 (Wikipedia, 2023c). The main culprit was a poor cement job that failed to prevent gas from escaping through the marine riser to the rig floor, where it subsequently ignited and exploded (BP, 2010). In 2012, well G4 on the Elgin wellhead platform in the UK Sector of the North Sea experienced an uncontrolled release of hydrocarbons into the atmosphere (Gibson, 2016). Although the failure of the production casing below its design pressure was the main cause of the incident, the compromised integrity of the cement sheath also contributed to the severity of the situation (Henderson and Hainsworth, 2014). In 2013, a natural gas well (ST A-3) blew out and caught fire in the Gulf of Mexico. The report concluded that the well encountered higher-than-expect temperatures, which affected the density of the completion fluid and hindered its ability to maintain pressure balance, allowing hydrocarbons to flow into the well (Snow, 2015). The primary cause of the 2015 Aliso Canyon gas leak (Wikipedia, 2023a) in the United States was that the well SS-25 was cemented only from the bottom to a depth of 6,600 feet, leaving more than a mile of steel pipe exposed to the rock formation. Gas leaked through a hole in the casing to the bottom of the outer casing and subsequently out through the rock to the surface (Maddaus, 2015).

During the process from cementing and completion to formal production of an oil and gas well, the cement sheath undergoes conditions such as casing pressure testing, fracturing, and oil testing. These operations alter the temperature and pressure within the wellbore, affecting the stress distribution on the cement sheath (Wang et al., 2020). If the mechanical properties of the cement sheath do not meet the demands of these wellbore conditions, interlayer sealing failure and sustained casing pressure (SCP) may occur (Liu et al., 2019; Teng et al., 2015; Zhang et al., 2018). SCP manifests as irreducible casing pressure that can rebuild after being released and is observed at the wellhead. A 2001 survey by the U.S. Minerals Management Service (MMS) reported that 11,498 casing strings in 8122 wells in the Gulf of Mexico exhibited SCP. According to a 2004 MMS report, approximately 6,650 wells had SCP, with 33% of these cases linked to leaking cement (Shadravan et al., 2014). As shown in **Figure 1.3**, data from offshore wells in the Gulf of Mexico indicated that SCP issues increase with the age of the well, with wells older than 15 years showing a barrier failure rate of 50% or more.

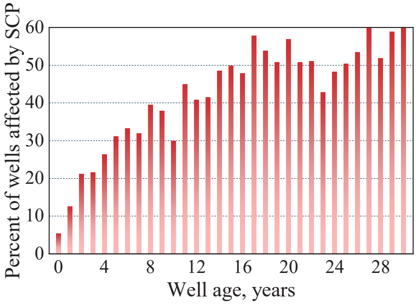

Figure 1.3 Wells with SCP by age (Brufatto et al., 2003).

Figure 1.4 presents data from shale plays in the U.S. and China, analyzed using different statistical methods. Combs et al. (2017) analyzed historical data on cementing, completion, and production operations in a representative shale area in the U.S., finding that 86.5% of drilled wells exhibited SCP of some rate. More than 30% of wells experienced no SCP pre-fracturing but showed SCP post-fracturing. Xi et al. (2020a) highlighted that nearly 80% of wells in China's Fuling shale gas field displayed SCP, with SCP rates exceeding 50% after multi-stage fracturing. Clearly, cement sheath integrity failure presents a serious issue.

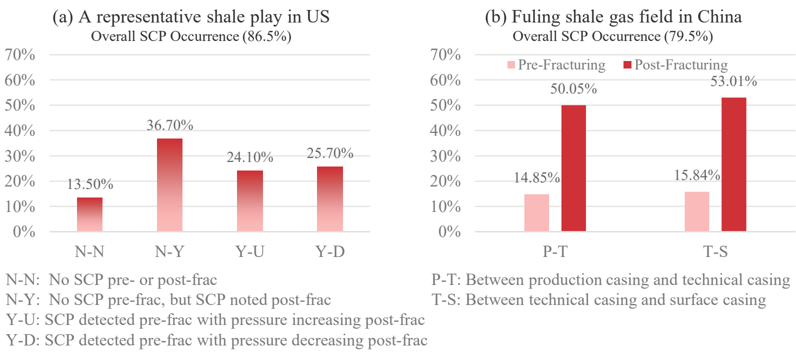

Figure 1.4 Overall occurrence of SCP in two shale plays in different regions.

The cement sheath plays a crucial role in maintaining zonal isolation, protecting the casing from corrosion, and providing mechanical support, all of which are vital for well integrity.

Preserving cement sheath integrity is essential for the safe and productive operation of oil and gas wells. Researchers have been studying the interaction of the casing-cement sheath-formation system under downhole temperature and pressure conditions to analyze the failure mechanisms and dominant factors affecting cement sheath integrity, with the goal of developing improvement strategies and control methods. One approach involves using finite element software to simulate and evaluate cement sheath integrity by inputting experimentally measured parameters and actual field conditions. This method analyzes how various parameters of the cement sheath change over time and identifies potential damage based on failure criteria. Additionally, a mechanical coupling model for the casing-cement sheath-formation system is employed to analyze the effects of changing cement sheath parameters on integrity. Some studies have developed cement sheath integrity evaluation devices, using laboratory experiments to assess cement sheath performance under downhole conditions. However, these studies primarily focus on overall integrity failure, with limited analysis of interface micro-annulus. Moreover, the evaluation devices are often simplistic and cannot accurately simulate the impact of actual underground conditions. Monitoring methods are also basic, often relying on visual inspection without sufficient experimental data.

Understanding the failure modes, causes, and influencing factors of cement sheath interlayer isolation under temperature and pressure conditions will help optimize the mechanical properties of the cement sheath and improve its interlayer isolation capability. In this context, this study conducted mechanical testing and integrity evaluation experiments on cement sheaths. A wellbore simulation device and an interlayer isolation test method were developed to replicate the wellbore stress environment. Through physical simulation experiments, potential factors contributing to cement sheath interlayer isolation failure were analyzed. Based on these factors, a cement sheath integrity evaluation method and an interface micro-annulus calculation model were established using elastic-plastic mechanics theory. The analysis also incorporated the effects of temperature-differential stress and combined stress on the cement sheath. A model was developed to evaluate cement sheath integrity under the coupled effects of temperature and pressure. Using these analytical models, the factors influencing cement sheath mechanical integrity were examined. Finally, experimental tests were conducted on cement sheath of various modified systems, including those with expansion or toughening agents, using the high-temperature and high-pressure integrity evaluation device. The research findings provide valuable insights for predicting and preventing cement sheath interlayer isolation failures under wellbore conditions.

1.2 State of the art and scientific challenges

1.2.1 Failure modes of cement sheath integrity

With the commercialization of hydraulic fracturing in the 1950s, fluctuations in wellbore pressure caused significant damage to the cement sheath, prompting the development of improved cementing practices (King and King, 2013). During the mid-1960s, issues related to annulus gas migration were identified during cementing operations in gas wells (Al Ramadan et al., 2019). Carter et al. (1973) conducted leak tests on mud displacement during cementing using a rig. Initially designed for research on mud displacement with cement slurries (Clark and Carter, 1973), the device involved an annulus mold created by drilling a core, forming a continuous column of mud or cement. Nitrogen was used as the gas medium to pressurize the core.

Early studies focused on gas migration during cement slurry displacement and curing, commonly referred to as gas channeling during cementing. At this stage, the main factors contributing to cement sheath integrity failure were identified as follows:

(1) Drilling fluid retention due to poor displacement efficiency (Sun et al., 2020).

(2) Poor cement bonding caused by mud cake (Li et al., 2022; Li et al., 2023).

(3) Incomplete annulus cementing job, failing to reach the seal layer (Bois et al., 2011).

(4) Interfacial micro-annulus due to cement hydration shrinkage (Sasaki et al., 2018).

(5) Channeling in the cement slurry (Nelson and Guillot, 2006).

(6) Primary permeability within the cement sheath or cement plug (Cooke et al., 1983).

(7) Failure of the casing due to burst or collapse (Cooke et al., 1983).

Advancements in cementing technology, such as dynamic cementing techniques (Holt and Lahoti, 2012), expanding cement (Baumgarte et al., 1999), self-healing cement (Taoutaou et al., 2011), have significantly mitigated early gas channeling problems in cement slurry. However, after the cement sheath solidifies, the long-term integrity issuse (Bois et al., 2012) can still arise during subsequent drilling or production phases. Over the lifespan of a well, changing downhole conditions can induce stresses that may compromise cement sheath integrity (Boskovic et al., 2010; Su et al., 2022; Su et al., 2021). **Table 1.1** outlines the typical working and stress conditions that the cement sheath may encounter during its service life.

Table 1.1 Possible main operations/events during the life of an oil well after cement placement (modified from (Jafariesfad et al., 2017))

Operation/events	Typical time of occurrence	Typical duration	Main affected property/load	Range of variation/example value
Cement hydration	Start earlier	Months	Autogenous (bulk shrinkage)	Volume reduction: 1–5% (Reddy et al., 2009)
Pressure testing	Hours	Hours	Pressure	50 MPa in a 244 mm, 69.9 kg/m casing results in a strain in the casing-cement interface of 1.25 milli strains (James and Boukhelifa, 2008)
Subsequent drilling	Days	Week	Mechanical load (shock wave), pressure, temperature	Drill string rotating at 100 rpm for 50 h Pressure variation if the mud weight has been changed to drill the next section (Thiercelin et al., 1997) Temperature increases of the cased section when the mud, which has been heated by the formation being drilled, returns to the surface via the annulus

				(Thiercelin et al., 1997)
Well completion	Weeks	Weeks	Pressure, temperature	
Perforation	Weeks	Day	Pressure, mechanical load (shock wave)	Pressure increase to values in excess of 40 MPa (Thiercelin et al., 1997)
Hydraulic fracturing	Years	Day (x times)	Pressure	Differential pressure: (7–55) MPa (Shadravan et al., 2014; Williams et al., 2011) Pressure increase is more damaging because the fluid injection lasts from minutes to hours (Thiercelin et al., 1997)
Hydrocarbon production	Year	Years	Pressure, temperature	Depends on production zone depth Pressure and temperature fluctuation mainly concerns the near-surface casing sections (Thiercelin et al., 1997)
Fluid injection	Years	Months (x times)	Pressure, temperature	Steam injection: a temperature increase of 250 °C results in a strain in the cement sheath at the casing interface of 3.25 milli strains (James and Boukhelifa, 2008) Injector well: Max. P = 8 MPa; ΔT = 45 °C results in 420 pressure cycles from (0–8) MPa (Pedersen et al., 2006)
Formation movement	Decades	Hours	Mechanical load	Dependent on formation creep-characteristics (Yang et al., 2021)

Mechanical damage to the cement sheath typically arises from significant increases in wellbore pressure (e.g., pressure testing, increased mud density, casing perforation, fracturing, production), wellbore temperature (e.g., geothermal production, fluid injection, high-temperature/high-pressure (HT/HP) wells), or formation loading (e.g., creep, faulting, compaction). The major failure modes of cement sheath integrity, as shown in **Figure 1.5**, can be categorized as follows:

1. **Inner debonding** is caused by casing contraction during heat/pressure cycling, when the cement sheath fails to follow casing deformations.
2. **Outer debonding** is caused by the casing pulling inward, when the cement sheath hydraulic bond weakening with the formation.
3. **Compression failure** is cement matrix crushing. Under the strong confinement by the formation or outer casing, the inner casing pushing outwards on the cement sheath, resulting in compressive stress larger than cement compressive strength.
4. **Circumferential crack / Disking** occurs by cement sheath axial contraction when the effective vertical stress is less than the cement tensile strength.
5. **Radial crack / Tensile failure** is caused by the high tensile stresses on the cement sheath resulting from the casing pushing outwards with minimum confinement by the formation.
6. **Shear damage** occurs when the cement sheath be submitted to a large deviatoric state of stress, which often caused by the casing damaged or the formation slips.

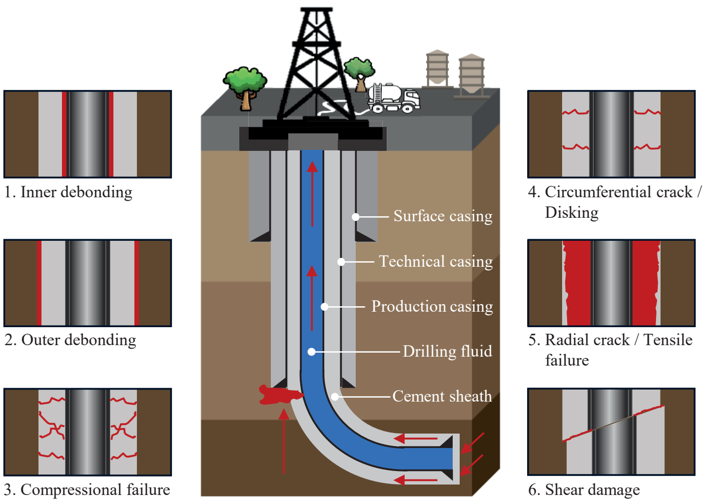

Figure 1.5 Major modes of cement sheath integrity failure

1.2.2 Experimental study on cement sheath integrity

Unlike studies focused on the mechanical properties of the cement sheath, which analyze parameters such as strength and deformation capacity, research on cement sheath integrity primarily addresses the structural damage and failure of the cement sheath under varying temperature and pressure conditions.

Goodwin and Crook (1992) were the pioneers in designing a test device to evaluate the overall sealing capability of cement sheaths under pressure loads. As shown in **Figure 1.6**, their research analyzed the failure modes of cement sheaths by placing the cement sheath between double-layered casing and applying temperature and pressure loads. The findings revealed that as the internal casing pressure increased, the casing expanded, leading to radial cracks in the cement sheath. The primary reason for this failure was that the compressive strength of the cement sheath could not withstand the pressure load exerted by the expanding casing. Re-tests conducted with ultra-high compressive strength cement systems showed that the cement sheath remained undamaged under the same pressure loads. However, excessive temperature increases also caused stress cracking within the cement sheath, highlighting temperature as another critical factor in its failure.

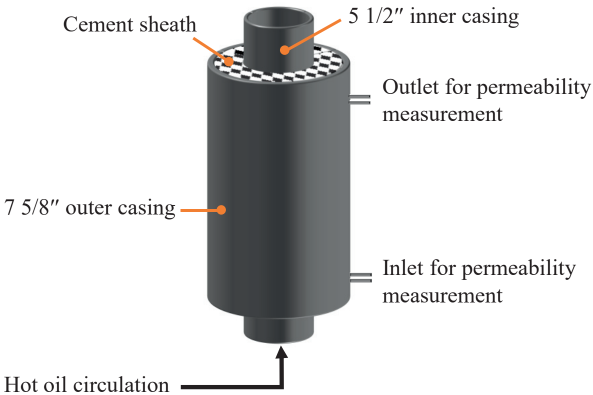

Figure 1.6 Schematic of the pressure-/temperature-change test model.

Boukhelifa et al. (2004) developed a large-scale experimental device (**Figure 1.7**) to evaluate