CO2 / CCS / CCUS
Well Equipment – Considerations

Comment Only Ballot Draft #6543

API Internal Use Report

Oct. xx, 2024

CO_2 / CCS / CCUS Well Equipment – Considerations

Comment Only Ballot Draft – XX Oct. 2024

This Page Is Intentionally Left Blank for Two-Sided Printing Purposes

CO_2 / CCS / CCUS Well Equipment – Considerations
Comment Only Ballot Draft – XX Oct. 2024

Table of Contents

Scope

Oil and gas production and injection equipment rely on API specifications, standards, and recommended practices to manage the equipment's design, manufacturing, and use. The related API specifications and standards provide the requirements for performance, design, materials, testing, inspection, welding, marking, handling, storing, and shipping of the equipment. Other Standards and Recommended Practices specify the equipment configuration and operating practices.

These documents rely upon the equipment's defined service conditions in terms of pressure, temperature, and wellbore fluids as their basis. With this information the equipment specific structural loading scenarios are determined and evaluated.

CO_2 / CCS / CCUS Well Equipment – Considerations
Comment Only Ballot Draft – XX Oct. 2024

This report's scope is to provide considerations for identified service conditions for production or injection wells used in CO_2, Carbon Capture Sequestration (CCS), or Carbon Capture Utilization and Storage (CCUS) applications. The report also outlines possible safety risks, failure mechanisms, and unique CO_2 / CCS / CCUS loading conditions that can be applicable for equipment and operating risk assessments.

The report's process flow scope begins with the pressure, temperature, fluid phase, and fluid composition when a CO_2 / CCS / CCUS flow stream exits the pipeline and enters the surface and downhole equipment associated with its injection into a reservoir. The report also addresses scenarios in which reservoir fluids with injected CO_2 / CCS / CCUS gases are brought back to surface.

Informative References

1. AMPP Guide 21532-2023, "Guideline for Materials Selection and Corrosion Control for CO_2 Transport and Injection", approved May 30, 2023(AMPP_SC20, 2023)
2. DNV CO2RISKMAN, "Guidance on CCS CO2 Safety and Environment Major Accident Hazard Risk Management", Documents Level 1 through 4, DNV Report No.: I3IJLJW-2, Re-issued 17 December 2021, Rev 3(Holt et al., 2021a, 2021b, 2021c, 2021d)
3. CO2 Specification JIP. (September 2024). Industry Guidelines for Setting the CO_2Specification in CCUS Chains: Introduction to the Guidelines (Rev 2). Wood Group UK Ltd. https://www.woodplc.com/insights/reports/Industry-Guidelines-for-Setting-the-CO2-Specification-in-CCUS-Chains(Wood_Group, 2024a, 2024b, 2024c, 2024d, 2024f, 2024e, 2024l, 2024j, 2024k, 2024i, 2024h, 2024g)
4. Meyer, J. P. (Prepared for the American Petroleum Institute). *Carbon Dioxide Enhanced Oil Recovery (*CO_2 *EOR) Injection Well Technology*. Contek Solutions, Plano, Texas.(Meyer, 2007)

Introduction

The commercial CO_2 EOR, carbon capture and sequestration (CCS), and carbon capture usage storage CCUS) chains span a broad number of areas. For simplicity, this report focuses on CCS projects, as many of its aspects apply to all the different project types.

CCS involves capturing CO_2 with various components at an emitter facility, transporting it to a storage site, and injecting it deep underground for permanent geological storage. CO_2captured from industrial processes is not 100% pure. It may contain various components depending on the capture method and the source of the CO_2. These components can include:

- Carbon monoxide (CO)
- Water (H2O)
- Hydrogen sulfide (H2S)
- Nitrogen oxides (NOx)
- Sulfur oxides (SOx)
- Oxygen (O2)
- Hydrogen (H2)

For this report, the term "CCS gases" is used to stand for pure 100% CO_2 or the combination of captured CO_2 with various other chemical components (ex. H2S, SOx, NOx, O2, H2, H2O, etc.).

Over the past decade, there have been significant academic and industry, and government research and documented studies on CCUS projects operations. This work is continuing today as more information, understanding, and experience is gained.

This report is meant to be a "snapshot in time" summary of identified CCS risks and equipment design and operations practice considerations for API specifications, standards, and recommended practices. **This document provides information intended to assist API standards development committees in identifying issues related to CO_2 for possible consideration in their respective standards pursuant to the consensus process found in API's Procedures for Standards Development. It is not intended as a recommended practice or industry standard and is intended for internal committee use only.** This report is not intended to offer requirements for individual CO_2 / CCS / CCUS projects. Each project's operator is responsible for their project's "functional requirements." Each equipment supplier or service provider is responsible for their respective "technical specifications" to meet the operators "functional requirements."

Informative Reference Document Summaries

The listed Informative reference documents are intended to give the reader greater detail about the subjects within this report.

1. *AMPP Guide 21532-2023, "Guideline for Materials Selection and Corrosion Control for CO2 Transport and Injection"*

   The AMPP Guide 21532-2023 provides guidelines for material selection and corrosion control in CO_2 transport and injection systems, particularly for Carbon Capture and Storage (CCS) projects. It outlines procedures for selecting materials that can handle the unique corrosion challenges posed by dense phase CO_2, which often contains CCS gas components like water, SOx, and NOx. The guide emphasizes the importance of managing operating conditions, CCS gas component concentrations, and corrosion mechanisms to ensure long-term integrity. Key topics include material recommendations, phase behavior analysis, and monitoring strategies to prevent failures such as cracking and embrittlement.

2. *DNV CO2RISKMAN DNV CO2RISKMAN, "Guidance on CCS CO2 Safety and Environment Major Accident Hazard Risk Management", Documents Level 1 through 4*

   The CO2RISKMAN guidance documents provide comprehensive safety and risk management advice for Carbon Capture and Storage (CCS) projects. These documents, developed under the DNV-led CO2RISKMAN Joint Industry Project (JIP), are structured into four levels. Level 1 gives an executive summary highlighting key safety concerns and risk management strategies for CCS, including handling large CO_2 inventories and the potential hazards associated with CO_2 stream leaks. Levels 2 to 4 provide increasingly detailed guidance, focusing on specific CCS chain links such as capture facilities, pipelines, and storage. Each level addresses hazard identification, risk assessment, and risk treatment across different phases and technologies involved in CCS operations

3. *CO2 Specification JIP. (September 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Introduction to the Guidelines (Rev 2). Wood Group UK Ltd. https://www.woodplc.com/insights/reports/Industry-Guidelines-for-Setting-the-CO2-Specification-in-CCUS-Chains*

   The *Wood Joint Industry Project (JIP) documents* provide comprehensive guidelines for setting the CO2 specifications in Carbon Capture, Utilization, and Storage (CCUS) chains. These guidelines are aimed at addressing the impacts of CCS gas components in CO_2 streams, which can affect safety, operational efficiency, and cost-effectiveness. The JIP consists of various work packages covering thermodynamics, chemical reactions, material and corrosion impacts, safety, transportation, and storage. The guidelines emphasize setting CCS gas component limits to maintain the integrity of the entire CCUS process, from capture through to storage. These documents also offer methodologies, including workflow diagrams and case studies, to guide industries in determining optimal CO_2 specifications for their projects, ensuring technical and environmental compliance. Key contributors include industry leaders like Aramco, Shell, and Equinor, along with research institutions such as Heriot-Watt University.

4. Meyer, J. P. (Prepared for the American Petroleum Institute). *Carbon Dioxide Enhanced Oil Recovery (CO2 EOR) Injection Well Technology*. Contek Solutions, Plano, Texas.

   This report examines technologies for CO_2 Enhanced Oil Recovery (CO_2 EOR) in oil fields, focusing on injecting carbon dioxide into reservoirs to boost oil production. The process relies on CO_2 miscibility with oil under pressure, reducing viscosity and enabling more efficient extraction. The report details well design, CO_2 injection procedures, corrosion control, and safety measures. It highlights the U.S. oil and gas industry's extensive experience, operating over 13,000 CO_2 EOR wells and injecting over 600 million tons of CO_2. Key technologies include corrosion-resistant materials like stainless steel and specialized cements for well integrity. The report emphasizes the potential for adapting CO_2 EOR technologies for large-scale geologic carbon storage.

Performance-Based Specifications, Standards and Practices

This report is based upon a combined risk-informed, performance-based approach to equipment Specifications, Standards and Recommended Practices. A performance-based approach, when combined with risk-informed principles, focuses on achieving measurable outcomes by integrating risk insights, engineering analysis, and performance history. This approach directs attention to the most critical activities, helping prioritization based on risk significance and operational importance.(NRC, 2015; Vietti-Cook, 1999)

Key attributes of this combined approach include:

- **Objective Criteria**: Establishing clear, measurable performance standards based on risk insights and engineering judgment, allowing for more focused assessment of safety and operational performance.
- **Flexibility**: Industry users have the freedom to determine how to meet these performance criteria, fostering innovation and improvement in outcomes. This flexibility allows organizations to optimize their processes while still achieving the desired results.
- **Measurable Parameters**: Performance monitoring is driven by quantifiable parameters, which can be directly measured or calculated from related data. These parameters help assess whether systems are performing as intended, ensuring the focus remains on results rather than procedural compliance.

- **Resilience to Failure**: The approach provides a framework where failing to meet a specific performance criterion does not automatically trigger safety concerns but prompts further evaluation and corrective actions. This ensures that performance shortfalls are addressed proportionally to their risk significance.
- **Focus on Outcomes**: The primary emphasis is on the end results—whether the system or process delivers the intended safety and operational performance. By concentrating on outcomes, the approach targets areas where performance is lagging, directing resources where they are most needed.

This combined risk-informed, performance-based approach encourages continuous improvement and more efficient resource allocation by aligning industry attention with actual risk and performance outcomes, leading to safer, more reliable industry operations.

CO_2 / CCS / CCUS Exposure / Safety Hazards

Commercial CO_2 / CCS / CCUS projects exposure hazards are driven by the challenges of handling pure CO_2 or CO_2 containing various components. Due to the large quantities of CCS gases involved, managing the risks associated with its release is critical. The key concern is the potential hazards of large-scale CCS gas releases, which can affect human health and safety. It is important to note that the gas release can take two forms "Cold Release" or "Super Critical Release". (Spitzenberger & Felchas, 2023)

"Cold Releases" happen when the CCS gases are in the liquid phase. If the system suffers a catastrophic failure, a white cloud forms. This cloud is not made of visible CCS gases but rather water vapor from the air that condenses due to the cold temperatures of the release. Solid CO_2 (dry ice) may also form on the ground near the release point and will eventually turn into gas. Individuals exposed to this release type may become disoriented, impacting their egress from the event.

During a "super critical" release, no visible cloud forms because the temperature is too high for water vapor to condense, and no solid CO_2 forms. Instead, the CCS gases go straight from supercritical to gas form. Thus, visual indications of a release may not be present to individuals.

CO_2 Exposure Levels and Symptoms

Here is a summary of the CO_2 exposure levels and their effects on human health, along with the risks posed by the components in captured CO2 streams.

CO_2 is colorless, odorless, and 1.5 times heavier than air, posing an asphyxiation hazard by displacing oxygen. Depending on its concentration, it can also have other harmful effects on the body, particularly the respiratory, cardiovascular, and central nervous systems. The Occupational Safety and Health Administration (OSHA) and other regulatory bodies have set exposure limits to protect workers, but high concentrations can still be dangerous. (USDA_FSIS_ESHG, 2022)

- 5,000 ppm (0.5%): This is the OSHA permissible exposure limit (PEL) for an 8-hour workday, as well as the threshold limit value (TLV) established by the American Conference of Governmental Industrial Hygienists (ACGIH). At this level, no adverse effects are typically expected during the workday.
- 10,000 ppm (1.0%): At this concentration, most people will not experience significant effects. However, mild drowsiness may occur, especially with prolonged exposure.
- 15,000 ppm (1.5%): Some individuals may experience mild respiratory stimulation, such as slight increases in breathing rate.
- 30,000 ppm (3.0%): This level leads to moderate respiratory stimulation, along with an increase in heart rate and blood pressure. It is designated as a short-term exposure limit (STEL) by the ACGIH, meaning that workers can be exposed to this concentration for short periods (15 minutes) without significant risk, provided the exposure is not prolonged.
- 40,000 ppm (4.0%): At this point, CO2 CO_2 is considered immediately dangerous to life or health (IDLH) by the National Institute for Occupational Safety and Health (NIOSH). Exposure at this level can result in more severe symptoms, including dizziness, confusion, and respiratory distress, which could rapidly escalate to unconsciousness or death if exposure continues.
- 50,000 ppm (5.0%): Strong respiratory stimulation occurs, accompanied by more severe symptoms such as dizziness, confusion, headaches, and shortness of breath. Immediate evacuation from such an environment is necessary to prevent serious health consequences.
- 80,000 ppm (8.0%): At this extremely high level, symptoms become critical, including dimmed vision, sweating, tremors, and rapid progression to unconsciousness, with a high likelihood of death if the individual is not rescued.

Components in Captured Stream

Although the additional components (e.g., H2O, SOx, and NOx, just to name a few) mixed with the CO_2 are in small quantities, these components can increase the risks associated with CCS gas exposure. For example, the presence of water in the CCS gas stream can lead to the formation of carbonic acid, sulfuric acid, and nitric acid, increasing the risk of equipment/pipeline failure leading to leaks and increasing the safety risks for personnel. Additionally, CCS gas components like H_2S and

SOx are toxic, compounding the hazards if they are released into the atmosphere during a CCS gas leak.(Connolly & Cusco, 2007)

Managing Risks in CCS Operations

Risks are managed by engineers and operators in CCS projects understanding the captured stream's properties and its behavior under different conditions. The stream can exist as a gas, liquid, solid, or supercritical fluid depending on the temperature and pressure. In well control scenarios, the gases may be in solution within the storage formation's fluids, such as in the case of injection into saline reservoirs. Most transportation systems carry CO_2 stream as a liquid or supercritical fluid to avoid a two-phase flow, which could complicate transportation. Thus, a release can be either a "Cold Release" or a "Super Critical Release, depending on the conditions present at the time of release.(Holt et al., 2012; Spitzenberger & Felchas, 2023)

The handling of large inventories of CCS gases from the pipelines and storage facilities includes the following design and hazard management processes:

- Monitoring and measuring captured stream components.
- Tightly controlling the CCS gas components within a prescribed limit
- Developing a practical phase diagram showing safe operating temperature and pressure range for CO_2 stream with CCS gas components that significantly differ from the pure CO2 CO_2 phase diagram.
- Facility and equipment design, selection, and layout that consider the corrosion, temperature, fluid expansion, and the heavier than air density aspects of CCS gases.
- Inspecting and maintaining wellsite facilities, wells, and temporary pressure control equipment.
- Having operating procedures and trained personnel in place
- Having emergency response procedures in place
- Understanding the long-term risks of sub-surface storage (e.g., (i) how the stored CO_2 plume will behave after 100 years? (ii) will there be any plume migration? (iii) can the migrated plume cause any blowout from legacy oils? (iv) can the groundwater be contaminated?)
- Placing proper monitoring and control methods for stored CO_2.

In summary, understanding the effects of different CO_2 concentrations and managing the risks of CCS gas components are fundamental for establishing safe and reliable CCS operations.

CO_2 EOR Design Considerations

The primary emphasis for this report is for CCS and CCUS applications. However, one cannot discuss those subjects without an acknowledgment about the industry's long history with CO_2 EOR applications.

API's "*Carbon Dioxide Enhanced Oil Recovery (CO2 EOR) Injection Well Technology"* report outlines the critical considerations for surface equipment, well design, corrosion control, materials selection, and maintaining mechanical integrity in CO_2 injection operations. This report was created in 2007. Part of its focus was to show potential CO2 EOR practices that may be relevant for CCS injection operations. Since the 2007 CO2 EOR report's creation, industry has learned that CCS gas components may create a very complex phase and corrosion environment.(Wood_Group, 2024d) However, for CO_2 EOR operations, much of the 2007 CO2 EOR report's technical basis, the surface equipment and well-related risks and discussions are still valid. The areas performing CO2 EOR operations have long existing operational history that can guide equipment design, material selection, and operating practices. Below is a summary of key aspects from the report.(Meyer, 2007)

The surface equipment for CO_2 EOR wells includes key components such as wellheads, trees, and upstream metering systems. The tree is essential for controlling CO_2 injection, and it is commonly designed with corrosion-resistant materials like 316 stainless steel (SS) for valve trim. Upstream metering and piping runs also rely on materials like fiberglass-reinforced epoxy (GRE) and 316 SS to handle the pressures and corrosive conditions associated with CO_2 injection. Automated control systems and pressure sensors are integrated into surface equipment to monitor flows and ensure well integrity.

CO_2 injection wells are designed with multiple casing strings to provide structural stability and isolate different geologic formations. The wellbore design must account for injection pressures and protection against potential CO_2 leakage. Cementing placement and quality is required to create a strong seal between the casing and the surrounding rock, which prevents CO_2 migration.

Corrosion is a significant challenge in CO_2 EOR, as carbon dioxide reacts with water to form carbonic acid, which can degrade steel components. Corrosion control measures include the use of internally plastic-coated (IPC) tubing or GRE-lined tubing, which provide barriers against acidic environments. Cathodic protection, both impressed and passive, is applied to prevent galvanic corrosion, while biocides and inhibitors further mitigate corrosion risks in the well.

To withstand the corrosive conditions of CO_2 EOR, materials like corrosion-resistant alloys (CRAs) such as 316 SS, Nickel, and Monel are used in wellheads, completion equipment, and valve components. Elastomers such as Buna-N (nitrile rubber) and Teflon are chosen for packers and seals due to their resistance to CO_2-induced swelling.

Maintaining mechanical integrity is crucial for long-term well performance. Mechanical integrity tests, including pressure monitoring in the casing-tubing annulus, are regularly conducted to ensure the well's pressure containing capabilities. Re-completed wells undergo additional testing, including squeeze cementing and casing integrity inspections, to confirm their suitability for CO_2 injection.

Derived from over 50 years CO_2 EOR experience, these practices have a history of reliable CO_2injection operations, well integrity, corrosion-related risks mitigation, and enhancing the overall safety and efficiency of EOR operations. Please refer to the actual report for additional detailed information if further understanding of CO_2 EOR applications is desired. The remainder of this report will focus on CCS applications.

CCS Gas Composition

The concentration range for CO_2 in gases associated with CCS systems typically exceeds 95 mol%. In CCS chains, the primary goal is to capture a CO_2-rich stream. While lower concentrations of CO_2 are also encountered, particularly in flue gases or natural gas streams, the systems and models in use for CCS often focus on streams with CO_2concentrations above 95%.

For specific applications, such as transport or storage, the CO_2 concentration can vary, but it is generally desired to maintain CO_2 purity as high as possible to ensure efficient operations and reduce the impact of CCS gas components on the system.

Components

The representative list of components that can exist in CO_2 streams for CCS systems includes the following categories of substances: (Wood_Group, 2024b)

- **Trace components**: These components are present in smaller concentrations and can be reactive. They include:
  - Sulphur oxides (SOX)
  - Nitrogen oxides (NOX)
  - Water (H2O)
  - Oxygen (O2)

    - Hydrogen sulfide (H2S)
    - Carbonyl sulfide (COS)
    - Carbon disulfide (CS2)
    - Ammonia (NH3)
- **Non-condensable gases**: These include methane (CH4), nitrogen (N2), argon (Ar), carbon monoxide (CO), and hydrogen (H2).
- **Hydrocarbons**: This group consists of n-alkanes, alkenes, and BTEX (Benzene, Toluene, Ethylbenzene, and Xylenes).
- **Glycols**: Commonly found glycols are Monoethylene glycol (MEG), Diethylene glycol (DEG), and Triethylene glycol (TEG).
- **Volatile organic compounds (VOCs)**: This category includes aldehydes (formaldehyde, acetaldehyde), alcohols (methanol, ethanol, propanol, etc.), and ketones (acetone).
- **Other compounds**:
    - Dimethyl ether (DME)
    - Iron pentacarbonyl ($Fe(CO)_5$)
    - Phosphorous compounds, though data on their presence is limited.
- **Metals**: Mercury (Hg) is the only metal that has been noted as soluble in CO_2 streams.

The captured gas composition from Direct Air Capture (DAC) consists primarily of high-purity CO_2, with the following typical values: (Wood_Group, 2024f)

- CO_2: ~95.79 mol%
- **Water (H2O)**: 0.02 mol%
- **Nitrogen (N2)**: 2.34 mol%
- **Oxygen (O2)**: 1.84 mol%
- **Argon (Ar)**: Present in trace amounts
- **Other Noble Gases**: Less than 25 ppmv

- **Other Non-Noble Gases**: Less than 3 ppmv

Properties

The basic properties of binary CO_2 mixtures, used for equipment design and operating conditions, are as follows:

1. **Phase Behavior (VLE and LLE)**:
    - Vapor-Liquid Equilibrium (VLE) and Liquid-Liquid Equilibrium (LLE) are critical for understanding the pressure and temperature conditions at which different phases coexist in binary CO_2 mixtures. This helps determine the behavior of CO_2 with CCS gas components under different CCUS operational conditions.
2. **Density**:
    - The density of CO_2 mixtures is important for designing pipelines and other equipment used in the capture, transportation, and storage phases of CO_2. Higher density allows for greater storage capacity in geological formations. The report provides extensive experimental data for binary CO_2 mixtures involving common CCS gas components such as CH4, N2, H2, and others.
3. **Derivative Properties (Speed of Sound, Heat Capacity, Joule-Thomson Coefficient)**:
    - Speed of sound (SoS) is a key property for determining flow rates in pipelines and assessing the risk of ductile fracture. The Joule-Thomson coefficient (JT) helps assess the temperature changes that occur when CO_2 is injected into reservoirs.
4. **Viscosity and Thermal Conductivity**:
    - These transport properties affect the flow of CO_2 in pipelines and the design of compressors and pumps. For CO_2 mixtures, Lennard-Jones (LJ) models are considered effective for predicting viscosity.
5. **Solid Formation (Dry Ice and Hydrates)**:
    - Solid CO_2 (dry ice) and hydrate formation are potential issues in CO_2 transport, especially under conditions involving CCS gas components like water can cause operational issues like pipeline blockages.

Equation of State (EOS)

These properties are derived from various models and equations of state, such as the Cubic Equation of State (EOS) and the GERG model, which are benchmarked against experimental data to ensure accuracy. An Equation of State (EOS) is a mathematical model that describes the relationship between key thermodynamic properties of a substance, such as pressure, volume, and temperature (PVT). EOS models help predict how substances, or mixtures of substances, behave under different conditions.

Past published work focused on well design and operations has extensively discussed phase behavior modeling. Here's a summary of how EOS are treated across those papers:

1. ***Development of a Fit-For-Purpose* CO_2 *Injection Model for Casing and Tubing Design***:
   - The paper discusses the **GERG-2008 EOS** as a commonly recommended model for CCS operations. However, the authors highlight its limitations, especially when CCS gas components are present in the CO2 stream and stress the need for a more fit-for-purpose EOS that accounts for multi-phase flow and CCS gas components such as H2, CH4, and N2. The GERG-2008 EOS is adopted for modeling CO_2 behavior but supplemented with sensitivity analysis to accommodate well-specific requirements.(McMillan et al., 2024)
2. ***Transient Flow Analysis for Well* CO_2 *Injection: Challenges and Methodologies to Consider for Well Design & Operating Envelope***:
   - This paper also focuses on the phase behavior of CO_2 during injection, where EOS are employed to predict phase transitions. It compares **Pressure-Temperature (P-T)** formulations, which are traditional for oil and gas flow, with the **Pressure-Enthalpy (P-H)** formulation. The latter is used when dealing with near-critical regions or narrow phase envelopes, as it better handles the internal energy changes during phase transitions. The paper emphasizes the use of compositional EOS to accurately model the behavior of CO_2 mixtures with CCS gas components.(Wejwittayaklung et al., 2024)
3. ***Influence of Phase Behavior in the Well Design of* CO_2 *Injectors***:
   - The discussion focuses on how phase behavior, modeled using an appropriate EOS, impacts the well design. The **Span and Wagner EOS** is mentioned as the EOS used in their modeling of CO_2 phase behavior during continuous and transient injection

scenarios. The paper also highlights the importance of using EOS to manage phase transitions in depleted reservoirs, which affect well integrity due to temperature drops caused by CO_2 expansion and Joule-Thomson cooling. (Acevedo & Chopra, 2017)

Wood Group Report - EOS Discussion

The recent Wood JIP Report recommends different EOS's based on the property being modeled:(Wood_Group, 2024b)

1. **Phase Behavior (VLE/LLE)**:
   - For polar components (e.g., water, alcohols), the **Cubic Plus Association (CPA)** EOS is preferred.
   - For non-condensable, trace gases, and hydrocarbons, **Cubic EOS** (Peng-Robinson or Soave-Redlich-Kwong) is commonly used.
2. **Density, Speed of Sound, Heat Capacity, and Joule-Thomson Coefficient**:
   - The **Extended GERG EOS** is the best choice for accurately predicting these properties in CO_2 mixtures.
3. **Viscosity**:
   - The **Lennard-Jones (LJ) model** is preferred for calculating viscosity, based on its alignment with experimental data.
4. **Dry Ice Formation**:
   - All **EOS** models provide acceptable accuracy in predicting the conditions for CO_2 solid formation (dry ice).

Across all papers, the key takeaway is that the choice of EOS is vital for accurately predicting the thermodynamic properties of CO_2 mixtures, especially under varying operational conditions. The complex nature of how the components within CCS gas affect its properties will continue to evolve as more field and test data becomes available.

CCS gas components in CO_2 injection streams can significantly affect the phase behavior and overall performance of the injection wells. Key effects include:

1. **Phase Envelope Alteration**: CCS gas components such as nitrogen (N2), hydrogen (H2), and methane (CH4) shift the CO_2 phase envelope. These CCS gas components raise the bubble point, which reduces the stability of the CO_2 fluid in dense-phase conditions, causing early phase transitions from liquid to gas. (McMillan et al., 2024; Wood_Group, 2024b)
2. **Cooling Effects**: CCS gas components can enhance cooling effects such as Joule-Thomson cooling, leading to lower temperatures in the wellbore. This can result in operational challenges like material embrittlement or hydrate formation. (Acevedo & Chopra, 2017)
3. **Multi-phase Flow**: CCS gas components in the CO_2 stream can cause multi-phase flow, leading to fluctuating pressure and temperature profiles, which affect flow assurance and the integrity of wellbore materials.(Wejwittayaklung et al., 2024)
4. **Corrosion and Material Integrity**: The presence of reactive CCS gas components such as hydrogen sulfide (H2S) and sulfur oxides (SOx) increases the risk of corrosion, which can compromise wellbore integrity, especially when combined with extreme phase behavior and temperature swings. (McMillan et al., 2024; Wood_Group, 2024l)

Impact of CCS gas components on CCS Well Equipment

Introduction

In Carbon Capture and Storage (CCS) systems, the management of CO_2 streams, including those with various CCS gas components, poses several technical challenges for the longevity and performance of key infrastructure components such as valves, chokes, trees, wellheads, casing, cement, tubing, subsurface safety valves (SSSVs), and packers. The introduction of trace CCS gas components, non-condensable gases, hydrocarbons, glycols, or volatile organic compounds (VOCs) has profound implications for water drop-out and subsequent corrosion, mechanical damage, and material degradation in these systems.

This expanded report will provide an in-depth exploration of the mechanisms that lead to water drop-out in CCS operations. It will also examine the impacts of planned and unplanned operating conditions and focus on how CCS gas components contribute to corrosion, mechanical failure, and elastomer degradation. Additionally, we will cover specific forms of degradation, such as sulfide stress cracking (SSC), stress corrosion cracking (SCC), pitting, and the effects of temperature and pressure loads on the structural integrity of the CCS components.

Mechanisms of Water Drop-Out and CCS Gas Component Effects

Water drop-out in CO_2 streams is influenced by CCS gas components that affect the phase behavior of CO_2, especially under the injection pressure, low-temperature conditions typical of CCS systems. The presence of water, even in trace amounts, leads to the formation of liquid phases or hydrates when CCS gas components in the CO_2stream shift the thermodynamic equilibrium of the system.

CCS gas component-Induced Phase Shifts

The most critical CCS gas components affecting water drop-out include:

Non-condensable gases (e.g., N2, O2, H2S, CO): These gases lower the solubility of water in the CO_2 stream, increasing the likelihood of water condensation at reduced temperatures or elevated pressures.(Rowe & Craig, 2024; Wood_Group, 2024h)

Hydrocarbons and VOCs: Hydrocarbons such as methane (CH4), ethane (C2H6), and higher alkanes (C3+), as well as aldehydes, can modify the phase behavior of CO_2 by altering its density and viscosity. This promotes the formation of liquid phases, where water can precipitate out as CO_2moves through pipelines and into reservoirs.(Rowe & Craig, 2024; Wood_Group, 2024l)

Glycols: While typically added to prevent hydrate formation, glycols can also modify the phase behavior of CO_2 in ways that facilitate water drop-out when operating conditions deviate from their intended ranges. (Rowe & Craig, 2024; Sonke & Paterson, 2022).

Non-Condensable Gases and Hydrate Formation

Non-condensable gases like N2 and CH4 can change the phase boundaries of the CO_2 mixture, resulting in the formation of liquid or solid phases, particularly in areas where temperatures drop due to the Joule-Thomson effect (a cooling effect that occurs when gases expand without heat exchange). (Sonke & Paterson, 2022) This phase shift can lead to hydrate formation, where water molecules form crystalline structures around gas molecules, leading to blockages in pipelines or equipment, and creating areas of localized corrosion due to trapped water.

Hydrocarbons and VOCs Impacting CO_2 Streams

Hydrocarbons and VOCs increase the complexity of the CO2 stream, particularly when pressure and temperature fluctuate. For instance, higher concentrations of methane or ethane can result in two-phase flow conditions (gas and liquid), which exacerbate water drop-out.(Millet et al., 2023; Wood_Group, 2024l) VOCs, especially aldehydes, can react with water and form secondary compounds, which are often acidic and further contribute to the corrosion processes.

Glycol Influence on Water Drop-Out

Glycols, particularly monoethylene glycol (MEG) and triethylene glycol (TEG), are used to inhibit hydrate formation in CO_2 transport. However, glycols can affect the overall solubility of water in the CO_2 stream. In systems with incomplete dehydration, glycols can paradoxically contribute to water drop-out under extreme pressure and temperature conditions.(Wood_Group, 2024l, 2024h)

Water Drop-Out in Well Components

Water drop-out can occur in various sections of CCS well infrastructure, including:

- Valves and chokes: Due to sudden pressure drops, these components are particularly susceptible to water condensation as the CO_2 expands. The resulting phase separation can lead to hydrate formation, mechanical blockage, and corrosion.(Wood_Group, 2024h)
- Trees, wellheads and tubing: In trees, wellheads and tubing, temperature fluctuations from CO_2 injection or phase changes can cause water to condense, especially near surface equipment or at points of pressure reduction.(Rowe & Craig, 2024; Sonke & Paterson, 2022)
- Packers and subsurface safety valves: These components can trap small amounts of water, which, in the presence of CCS gas components, can form corrosive acids leading to crevice corrosion and eventual failure.(AMPP_SC20, 2023; Haaften et al., 2023)

Planned and Unplanned Operating Conditions That Promote Water Drop-Out

Planned Operating Conditions

Under normal operating conditions, CCS systems are designed to manage water content carefully, typically maintaining dehydration levels below critical thresholds to avoid condensation or hydrate formation. However, water drop-out may still occur during specific operational phases, such as:

- Start-up: During start-up, pressure and temperature are ramped up slowly, which may cause the CO_2 to pass through temperature ranges where water solubility decreases, leading to drop-out.(Haaften et al., 2023)
- Shut-in conditions: When CO_2 injection is halted, the static environment in the tubing can cool rapidly, leading to condensation and water drop-out.(Haaften et al., 2023)
- Planned maintenance events: These events often involve depressurizing parts of the system, which causes cooling through expansion, promoting water condensation.(Rowe & Craig, 2024; Sonke & Paterson, 2022)

Unplanned Operating Conditions

Unplanned events such as equipment failures or system malfunctions can lead to significant deviations in temperature and pressure, increasing the risk of water drop-out.

Hydrate formation due to cooling effects: If valves malfunction, causing rapid pressure drops, the Joule-Thomson effect can drastically cool the CO_2 stream, leading to sudden hydrate formation.(Marya, 2023; Wood_Group, 2024l)

Pressure surges and pipeline interruptions: Any interruption in flow that results in backpressure or sudden pressure reduction can shift the phase equilibrium of the CO_2, leading to water drop-out.(Marya, 2023; Wood_Group, 2024d)

Acids Formed by CCS Gas Components and Water Drop-Out

Water drop-out, combined with the presence of CCS gas components, leads to the formation of highly corrosive acids in the system. These acids pose significant risks to the longevity and integrity of CCS infrastructure.

Carbonic Acid (H2CO3)

Even in small quantities, carbonic acid forms when CO_2 dissolves in water. Although weak, in the presence of chloride ions, this acid can catalyze pitting and other forms of localized corrosion, particularly in carbon steel.(Millet et al., 2023; Wood_Group, 2024d)

Sulfuric and Nitric Acids (H2SO4 and HNO3)

Sulfur oxides (SOx) and nitrogen oxides (NOx) can react with water to form sulfuric and nitric acids, respectively. These acids are far more aggressive than carbonic acid and can lead to rapid material degradation, particularly in the case of carbon steel used for casing and tubing.(Wood_Group, 2024d, 2024h) In wells where water drop-out occurs frequently, these acids will attack the exposed surfaces of critical equipment, significantly increasing maintenance requirements and the risk of catastrophic failure.

Hydrochloric Acid (HCl)

Hydrochloric acid can form in CO_2 streams containing trace amounts of chlorine or halogenated hydrocarbons. In environments where water is present, HCl is highly corrosive, causing rapid degradation of metallic surfaces, especially at high temperatures and pressures.(AMPP_SC20, 2023; Wood_Group, 2024d)

Corrosion Mechanisms in CCS Systems

Corrosion is a critical concern in CCS systems due to the interaction of CCS gas components, water drop-out, and the injection pressure environment typical of CO_2 transport and injection. Various types of corrosion mechanisms affect different components such as valves, trees, wellheads, casing, tubing, and completion equipment often leading to costly repairs or system failures. This section explores the major corrosion mechanisms that occur due to the interaction of water and CCS gas components in the CO_2 stream.

Sulfide Stress Cracking (SSC)

Sulfide stress cracking (SSC) occurs in materials that are exposed to hydrogen sulfide (H2S) in the presence of tensile stress. SSC is particularly dangerous in high-strength steels, which are often used in well components like tubing, casing, and wellheads. When H2S dissolves in water (from water drop-out), it forms weak sulfuric acid that significantly reduces the resistance of steel to tensile stresses.

Hydrogen atoms can diffuse into the metal, causing embrittlement and facilitating crack propagation under tensile load. SSC is more prevalent in environments with high H2S concentrations and lower pH levels, such as those that might arise from the reaction of H2S with water in impure CO_2 streams.(Millet et al., 2023; Wood_Group, 2024d)

Stress Corrosion Cracking (SCC)

Stress corrosion cracking (SCC) occurs when a material under tensile stress is exposed to a corrosive environment, typically involving chlorides or sulfur compounds. In CCS systems, chloride ions can be present in both the CO_2 stream and the formation fluids. SCC is especially dangerous because it can lead to sudden, brittle failures of high-strength materials without any visible deformation.

The formation of nitric acid (HNO3) and sulfuric acid (H2SO4) from NOx and SOx in impure CO_2 streams further exacerbates SCC by promoting an aggressive corrosive environment. The acids formed lower the pH of the surrounding environment, increasing the likelihood of crack initiation and propagation.(Millet et al., 2023; Rowe & Craig, 2024; Wood_Group, 2024d)

Pitting Corrosion

Pitting corrosion is a localized form of corrosion that results in small, deep holes in a metal surface. This type of corrosion is particularly dangerous because it can be difficult to detect and monitor, yet it can rapidly weaken a material. Pitting often occurs in areas with high chloride concentrations or where oxygen is present in the CO_2 stream, both of which are common in impure CO_2 systems.

Water drop-out exacerbates pitting corrosion by creating localized aqueous environments where chloride ions or acids can accumulate. Components such as casing, tubing, and lower completion equipment which are in constant contact with CO_2 and formation fluids, are especially vulnerable to pitting.(AMPP_SC20, 2023; Marya, 2023)

Crevice Corrosion

Crevice corrosion occurs in small, confined spaces where fluid flow is restricted, leading to the buildup of corrosive species. In CCS systems, crevice corrosion is common in bolted connections, gaskets, subsurface safety valves and packers. The stagnant environment within these crevices allows CCS gas components such as chlorides or sulfur compounds to concentrate, promoting rapid corrosion.

For example, packers and seals are often exposed to condensed water in combination with acidic gases like H2S and CO_2. The confined spaces around these components provide an ideal environment for crevice corrosion, especially in cases where the CO_2 stream contains CCS gas components that form acids.(Haaften et al., 2023; Rowe & Craig, 2024)

Erosion and Fretting Corrosion

Erosion corrosion is the result of the mechanical wear caused by fluid flow, which removes protective films from metal surfaces, exposing them to further chemical attack. Erosion is particularly severe in high-flow areas such as valves, chokes, and surface lines downstream of chokes or restrictions. As the CO_2 stream containing solid particles, hydrates, or liquid droplets flows through these components, it erodes the protective oxide layers, leading to accelerated corrosion.

Fretting corrosion occurs when small, repetitive movements between metal surfaces cause the protective film to wear away. This type of corrosion is common in subsurface safety valves (SSSVs), packers, and other mechanical components that experience vibration or small movements due to changes in pressure and temperature.(Marya, 2023; Sonke & Paterson, 2022)

Mechanical Failures Due to CCS Gas Components and Water Drop-Out

In addition to corrosion, mechanical failures in CCS systems are often exacerbated by the presence of CCS gas components and water drop-out. The following sections detail the mechanical degradation mechanisms, including ductile and brittle fractures, hydrogen fatigue, and low-temperature embrittlement.

Ductile Fracture Propagation

Ductile fracture occurs when a material deforms plastically before breaking. In CCS systems, the presence of water drop-out and CCS gas components can create localized areas of stress concentration, which increase the likelihood of ductile fracture.

When CCS gas components such as sulfur oxides or nitrogen oxides react with water, they form acids that corrode protective films on metal surfaces, weakening the material and making it more susceptible to ductile fracture. Components such as casing, tubing, and surface lines, which experience high-pressure differentials, are particularly vulnerable to ductile fracture propagation.(Rowe & Craig, 2024)

Brittle Fracture

Brittle fracture is characterized by a sudden failure of the material without significant plastic deformation. It is especially dangerous in low-temperature environments, such as those experienced during CO_2 injection when the Joule-Thomson effect cools the CO_2 stream. Low-temperature embrittlement, combined with the presence of CCS gas components, can lead to catastrophic brittle fractures, particularly in high-strength steels used in casing, tubing, trees, wellheads and other well related equipment.(Haaften et al., 2023; Millet et al., 2023)

Hydrogen Fatigue

Hydrogen fatigue occurs when hydrogen atoms diffuse into a metal and cause embrittlement, reducing the material's ductility and toughness. In CCS systems, hydrogen may be introduced into the CO_2 stream through CCS gas components or from the formation itself. Repeated pressure cycling, as seen during CO_2 injection and shut-in periods, exacerbates the fatigue process, leading to premature material failure.

High-strength steels, commonly used in well components, are particularly susceptible to hydrogen-induced fatigue. The presence of water and hydrogen-sulfide CCS gas components in the CO_2 stream accelerates this degradation mechanism.(Haaften et al., 2023; Millet et al., 2023)

Elastomer Degradation and Gas Entrainment

Elastomeric components, such as seals, O-rings, and packers, are widely used in CCS systems to ensure proper sealing and prevent leakage. However, these materials are highly sensitive to the presence of CCS gas components in the CO_2 stream, which can cause rapid gas decompression, gas entrainment, and elastomer hardening.

Gas Entrainment and Decompression

Gas entrainment occurs when elastomers absorb CO_2 or other gases under high pressure. When the pressure is reduced rapidly, as in the case of an unplanned depressurization event, the entrained gases expand within the elastomer matrix, causing it to crack or rupture. This phenomenon is particularly concerning in subsurface safety valves (SSSVs), wellhead seals, and packers.(Haaften et al., 2023; Millet et al., 2023)

Elastomer Hardening and Other Effects

Over time, exposure to CCS gas components such as glycols, hydrocarbons, and VOCs causes elastomers to harden, losing their flexibility and resilience. This hardening effect reduces the ability of elastomers to maintain a tight seal, leading to potential leaks in dynamic systems such as valves, chokes, and packers.

Moreover, rapid gas decompression events can cause the elastomer to undergo severe cracking, which can compromise the integrity of critical seals and lead to failure under pressure cycling conditions(Marya, 2023; Sonke & Paterson, 2022)

Sealing and Functioning Difficulties

Sealing integrity is a crucial aspect of any Carbon Capture and Storage (CCS) operation, ensuring that CO_2 and CCS gas components remain contained within the transport and injection system. CCS gas components, water drop-out, and varying operating conditions significantly affect the performance and longevity of seals in components such as valves, wellheads, tubing, and subsurface safety valves. The degradation of seals not only leads to gas leakage but can also result in catastrophic system failures due to pressure loss or contamination of the surrounding environment.

Elastomer Gas Entrainment

Elastomer-based seals are commonly used in CCS systems because of their flexibility and ability to withstand various pressures and temperatures. However, one of the major risks associated with elastomers is gas entrainment. Under injection pressure conditions, CO_2 and other non-condensable gases can diffuse into the elastomeric material. When the pressure is suddenly reduced during operational events, the entrained gases expand rapidly within the elastomer, causing it to crack or rupture.

This phenomenon is known as rapid gas decompression (RGD). RGD is especially problematic in seals used in subsurface safety valves (SSSVs) and packers, where even minor seal failures can lead to the uncontrolled release of CO_2. Testing and material selection must account for the likelihood of RGD events, and the use of specially formulated elastomers designed to resist gas decompression is recommended.(Haaften et al., 2023; Marya, 2023)

Elastomer Hardening and Brittleness

Another common failure mode for elastomer seals is hardening due to prolonged exposure to CCS gas components such as glycols, hydrocarbons, and volatile organic compounds (VOCs). Over time, these chemicals cause the elastomer to lose its flexibility and resilience, making it more susceptible to cracking, especially under pressure cycling or thermal shock conditions. Hardening reduces the sealing capacity of elastomers, leading to gas leaks around valves, packers, and wellheads.

In high-pressure environments, the loss of seal integrity can result in dangerous pressure losses and compromised well integrity. This issue is exacerbated by frequent cycling between injection and shut-in phases, where the temperature and pressure fluctuations place additional strain on already hardened elastomers.(Haaften et al., 2023; Millet et al., 2023)

Chemical Attack on Seals

Elastomer seals can also suffer from chemical degradation when exposed to the acids formed from CCS gas components in the CO_2 stream. Sulfuric acid (H2SO4), nitric acid (HNO3), and carbonic acid (H2CO3), formed from SOx, NOx, and CO_2 reacting with water, can break down the elastomer structure at a molecular level. This chemical attack leads to the swelling, softening, and eventual failure of the seal, especially in critical components like wellheads and subsurface safety valves.(AMPP_SC20, 2023; Sonke & Paterson, 2022)

Sealing Failures in Packers, Trees, and Wellheads

Packers, trees, and wellheads are subjected to extreme temperature and pressure fluctuations during the CO_2 injection process. CCS gas components in the CO_2 stream, such as hydrogen sulfide (H2S) and volatile organic compounds (VOCs), contribute to seal degradation in packers, leading to reduced isolation between the injection tubing and the annulus. Over time, this can cause fluid migration, reduced injection efficiency, and even environmental contamination due to gas leaks.

In trees and wellheads, where sealing elements are exposed to water drop-out and the associated formation of corrosive acids, the risk of chemical attack is even more pronounced. The long-term degradation of these seals may result in compromised well integrity, making it essential to monitor seal performance regularly and replace them as part of planned maintenance schedules.(Millet et al., 2023; Rowe & Craig, 2024)

Impact of Low-Temperature Embrittlement on Seals

Low-temperature embrittlement is a particular concern for elastomers used in CCS applications, as the Joule-Thomson effect during CO_2 expansion can cause significant cooling, sometimes down to -80°C. Under such low-temperature conditions, elastomers lose their flexibility and become brittle, increasing the likelihood of cracking or seal failure. This is especially dangerous in high-stress areas such as subsurface safety valves and packers, where seal integrity is critical to maintaining well control and isolation.(Haaften et al., 2023; Sonke & Paterson, 2022)

Selection of Elastomers for CCS Applications

Choosing the right elastomer for CCS applications is critical for maintaining seal integrity under the harsh conditions of CO_2 transport and injection. Fluorocarbon elastomers (FKM) and perfluoro elastomers (FFKM) are commonly used due to their superior chemical resistance and high-temperature stability. Different elastomer materials may exhibit varying levels of resistance to the acids and components that can be encountered in the CO_2 stream.(Marya, 2023; Millet et al., 2023)

Operational Mitigation Strategies for CCS gas components and Water Drop-Out

Operational planning and selection of the appropriate materials and components can mitigate the adverse effects of CCS gas components and water drop-out in CCS systems and can be reduced by the following strategies:

Dehydration of CO_2 Streams

A CO_2 stream that is thoroughly dehydrated before it enters the transportation or injection pipeline can prevent water drop-out. Dehydration systems, such as molecular sieves, triethylene glycol (TEG) dehydration units, or solid desiccants, can reduce the water content of the CO_2 stream to levels below the saturation point, thus minimizing the risk of water condensation and acid formation.(Sonke & Paterson, 2022; Wood_Group, 2024l)

Monitoring and Maintaining Operating Conditions

Regular monitoring of pressure, temperature, and flow rates can maintain the CO_2 stream within its intended operating envelope. Sudden changes in operating conditions, such as rapid depressurization or temperature fluctuations, can lead to water drop-out or the formation of hydrates. Implemented automated systems that detect pressure surges or temperature drops adjust operating parameters in real-time and can prevent unplanned shutdowns.(Marya, 2023; Wood_Group, 2024h)

Material Selection for Corrosion Resistance

Selecting corrosion-resistant materials for critical components such as trees, wellheads, valves, chokes, casing, tubing, subsurface safety valves and packers can prevent failure due to water drop-out and CCS gas component-induced corrosion. This is especially important for equipment in lower completion areas exposed to the near wellbore reservoir interface (i.e. perforations) and flowback fluids during shut-ins. Considerations to the ability of inspection and repair over the well's full life cycle is important. Corrosion-resistant alloys (CRAs) such as Inconel, super duplex stainless steels, nickel-based or Titanium alloys can be used for high-risk areas where the CO_2 stream contains high concentrations of H2S, NOx, SOx, O2, or chlorides.(AMPP_SC20, 2023; Rowe & Craig, 2024).

Use of Corrosion Inhibitors

Corrosion inhibitors injected into the CO_2 stream or formation can prevent the acids formed from reacting with metal surfaces. These inhibitors form a protective film on the surface of the metal, reducing the likelihood of pitting, SCC, and SSC. Regular maintenance and replenishment of the inhibitor levels can provide protection against corrosive environments.(Marya, 2023; Wood_Group, 2024h)

Preventing Hydrate Formation

To prevent hydrate formation, chemical additives such as methanol or monoethylene glycol (MEG) can be injected into the CO_2 stream. These chemicals lower the freezing point of water, preventing the formation of hydrates that could block pipelines or valves. However, the use of these chemicals can contribute to elastomer degradation or other chemical interactions within the system.(Marya, 2023; Wood_Group, 2024l)

Section Conclusion

The presence of CCS gas components such as trace components, non-condensable gases, hydrocarbons, glycols, and VOCs in CO_2 streams can significantly impact the performance and integrity of key components in CCS systems, leading to water drop-out, corrosion, mechanical failures, and elastomer degradation. Effective mitigation strategies, such as the use of corrosion-resistant materials, appropriate dehydration methods, and continuous monitoring of operating conditions, can support the long-term viability of CCS infrastructure.

Understanding the interactions between CCS gas components, water drop-out, and system components is crucial for developing robust solutions that prevent failure and ensure safe, reliable CO_2 storage. Ongoing research into material selection, chemical resistance, and operational best practices will continue to improve the safety and efficiency of CCS systems worldwide.

CCS / CCUS Additional Design Considerations

Pipeline Flow and Discharge Conditions

During the operation of CCS pipelines, several flow challenges arise due to varying terrains and environments. These challenges are primarily related to the thermodynamic behavior of CCS gases. This affects the pipeline's hydraulic performance and makes it difficult to maintain the CCS gas in a stable, dense phase, which is critical for minimizing pressure drops, avoiding phase changes, and water "drop out" within the pipeline.

Additionally, changes in the CCS gas compositions, as well as shifts in the reservoir pressure over time, present operational challenges such as hydrate formation, corrosion risk, and shutdown instabilities.

When CCS gas exits the pipeline, the conditions are highly dependent on the operational parameters maintained throughout its transportation. Typically, CO_2 is transported in a dense phase (high pressure and moderate temperature).. However, fluctuations in the pressure or temperature, can cause a two-phase condition, which includes both gas and liquid. If the pipeline operates near the CO_2 critical point of, there is a risk of the CO_2 entering the two-phase region, leading to operational complications such as pressure drops, reduced flow efficiency, and potential pipeline damage due to hydrate formation or corrosion.(Wood et al., 2021)

The pipeline operators have established gas specifications and parameters to operate their pipeline. The following are considerations for equipment downstream of the pipeline discharge.

- Single point emitters into a pipeline w typically have better control over their CCS gas compositions and operations. However, unplanned upsets can always occur, and non-spec gas may enter the pipeline.
- Hub facilities will be receiving CCS gases from multiple sources and will be combining and treating the gases before they enter the pipeline. Small variations of pressure, temperature, and volume associated with the CCS gas components, have recently been found to have

larger than expected effects on the total CCS gas composition's overall phase behaviorand the risk of two-phase behavior.(Wood_Group, 2024f)

Minimum Design Temperature

For CCS well-related equipment, a key design parameter is the equipment's minimum temperature rating. CCS wells pressure and high temperature ratings are very similar to traditional oil and gas wells. However, the equipment may be subjected to much lower temperatures than traditional oil and gas wells.

For example, the tables below show the current temperature ratings for Specification 16A Table 3 for Metallic Materials and Table 4 for Nonmetallic Sealing Materials.

Table 3—Temperature Ratings for Metallic Materials

Classification	Operating range	
	°C	°F
T-75/250	– 59 to 121	– 75 to 250
T-75/350	– 59 to 177	– 75 to 350
T-20/250	– 29 to 121	– 20 to 250
T-20/350	– 29 to 177	– 20 to 350
T-0/250	– 18 to 121	0 to 250
T-0/350	– 18 to 177	0 to 350
NOTE Information on strength of materials at elevated temperatures is found in API 6A and API 6MET.		

Figure 1: Specification 16A Table 3 for Metallic Material

Table 4—Temperature Ratings for Nonmetallic Sealing Materials

Low Temperature Limit (first digit)			**Continuous Elevated Temperature Limit[a]** (second digit)			**Extreme Temperature Limit** (third digit)		
Code	Temperature		Code	Temperature		Code	Temperature	
	°C	°F		°C	°F		°C	°F
A	– 26	– 15	A	66	150	A	82	180
B	– 18	0	B	82	180	B	93	200
C	– 12	10	C	99	210	C	104	220
D	– 7	20	D	116	240	D	121	250
E	– 1	30	E	132	270	E	149	300
F	4	40	F	149	300	F	177	350
G	Other	Other	G	Other	Other	G	Other	Other

Figure 2: Specification 16A Table 4 for Nonmetallic Sealing Materials.

The issue with CCS wells is that for many operating, extreme, or survival scenarios the equipment may be exposed to temperatures below the current low temperature ratings shown in the two tables above. The situation is further complicated by the fact that the latest research shows that the varying concentrations of components and the pressure they are under can have significant effects on their phase behavior, expansion rates, and temperatures. Especially when going through a Joule Thomson effect. The only real known temperature is where the CO_2 becomes “Dry Ice”, or a solid, -78.5°C (-109.3°F).

Currently, it appears that there is insufficient data and experience to be able to set a standard temperature rating across API. This is due that the various pieces of equipment may see widely different low temperatures given where they are in the CCS process flow.

CCS Project Operators typically define their expected low temperatures based upon their project’s expected CCS gas composition. Often this is a single value based upon a deterministic analysis. Due to the complexities associated with CCS operations, an approached based upon API Standard 17G’s definitions for “normal load”, “extreme load” and “survival load” may be a better way to describe and manage the temperature ranges that the equipment may encounter. Those respective definitions are:

- *Normal Load Condition: Regularly expected environmental and/or operational loading condition with a probability of occurrence greater than extreme condition based upon an appropriate risk assessment, for the period under consideration.*
- *Extreme Load Condition: Unavoidable but predictable load condition due to environmental and/or operating scenarios*

- *Survival Load Condition: Load condition is more severe than extreme conditions (which may be unplanned) in which equipment, after exposure, is required to maintain critical safety functionality.*

Well Life – CCS versus Oil & Gas

The lifespan of carbon capture wells and oil and gas wells differs significantly due to the nature of their operations, environmental factors, and regulatory requirements.

1. *Carbon Capture Wells:* Carbon capture and sequestration (CCS) wells are designed with a much longer regulatory life expectancy. Unlike oil and gas wells, the pressure in CCS wells starts low and increases over time as CCS gas is injected. CCS wells must maintain their integrity not only during active operation but also for a long period after abandonment. This extended lifespan is critical to ensure that the stored CCS gas remains securely trapped underground without leakage, necessitating designs that can handle corrosive environments caused by CCS gas and water mixtures. Due to the long-term exposure to corrosive conditions, Regulatory bodies may require the use of corrosion-resistant materials and dual barriers to prevent CCS gas releases or migration. (Ceyhan et al., 2022)

2. *Oil and Gas Wells:* In contrast, the life expectancy of oil and gas wells is generally much shorter. The highest reservoir pressures are experienced usually at the start of the well's life and gradually decrease as the hydrocarbons are extracted. Although some oil and gas wells are converted for other uses, such as gas storage, they are not usually subject to the same long-term environmental pressures as CCS wells. (Ceyhan et al., 2022)

Pressure Control Equipment & Well Control

Introduction

The operations involved in drilling, maintaining, and controlling wells, especially in the context of Carbon Capture and Storage (CCS) and CO_2 sequestration, present unique challenges. These challenges range from managing the thermodynamic behavior of injected CCS gas to ensuring robust well control during unexpected blowouts. Understanding the limitations and risks associated with Blowout Preventers (BOP), pressure control equipment, and well control strategies is critical to ensuring the safety and success of operations.

This report will focus on the challenges related to BOP, pressure control equipment, and well control operations, particularly in CO_2 wells, as discussed in various technical papers. These challenges are amplified in CCS operations due to the distinct properties of CO_2, such as its behavior under different pressure and temperature conditions, its phase transition, and its interaction with drilling fluids and well equipment. The discussion will also draw on knowledge from the oil and gas industry, as several operational principles remain relevant in CCS contexts.

Well Control Composition Uncertainty

It is important to note that most of the research and evaluations have focused on the CCS gas compositions associated with the capture, transport, and injection into the storage formations. The CCS gas fluid compositions associated with well control scenarios are less understood. How the CCS gases interface with the existing depleted reservoir fluids or saline reservoir fluids will always have a level of uncertainty. Many of the planned CCS projects will be taking CCS gases from multiple sources over time. So, the risk associated with CCS gas components may be higher for well control operations versus normal injection operations. That said, the well control risk may be lower if the reservoir's lithology creates a buffering effect and raises the injection gas's pH. Therefore, predicting well control fluid compositions will be most likely be project specific and based upon project's past experience.

Blowout Preventer (BOP) Challenges

BOPs play a critical role in preventing uncontrolled release of well fluids during drilling operations. However, when dealing with CO2 wells, their effectiveness can be compromised by various factors associated with CO2's physical and chemical properties.

Impact of CO2 Properties on BOP Functionality

- **Hydrate and Ice Formation:** If CO_2 is released during a well control incident, rapid expansion and cooling due to Joule-Thomson effects can lead to hydrate or ice formation on the BOP equipment. This can compromise the operation of the BOP and lead to failure during critical moments.(Connolly & Cusco, 2007; Zhou et al., 2022, 2024)
- **Phase Transitions:** CO_2 exists as a supercritical fluid under certain downhole conditions. If BOPs are not designed to account for the supercritical phase, unexpected phase transitions during pressure changes could affect the integrity of seals and the control mechanisms within the BOP. (Skogestad et al., 2024; Zhou et al., 2024)

Design and Maintenance Considerations

- **Supercritical CO_2 Challenges:** Supercritical CO_2 can expand rapidly upon depressurization, leading to potential failure in pressure control equipment. This necessitates specialized BOP designs capable of handling such transitions. (Zhou et al., 2022) In conventional hydrocarbon wells, BOPs are typically designed for gas or liquid behavior, but CO2 wells pose unique challenges, requiring designs that account for both gas and liquid phases under supercritical conditions. (Zhou et al., 2024)
- **Testing and Standards:** Current testing standards may not fully cover the conditions specific to CO_2 wells. It is necessary to develop new testing protocols and materials that can withstand the extreme temperature and pressure fluctuations characteristic in the case of aCO_2 blowout. ((Oldenburg & Pan, 2019)

Pressure Control Equipment Challenges

Pressure control equipment, such as chokes and valves, is vital for maintaining well integrity and controlling flow rates. However, CO_2's behavior under injection pressure conditions can exacerbate existing challenges or create new ones.

Joule-Thomson Cooling Effects

- **Pressure Drops Leading to Freezing:** As CO_2 passes through pressure control equipment, significant temperature drops occur due to the Joule-Thomson effect. This can lead to freezing of water vapor within the equipment, potentially causing blockages and operational failures(Connolly & Cusco, 2007; Skogestad et al., 2024; Zhou et al., 2024) The formation of hydrates at the surface or in valves, as seen in both onshore and offshore CO_2 blowouts, is a significant concern (Oldenburg & Pan, 2019)
- **Hydrate Management:** In deepwater or high-pressure scenarios, hydrate management becomes essential. Effective hydrate prevention methods, such as the use of hydrate inhibitors, heating, or insulation of equipment, must be part of the pressure control strategy(Skogestad et al., 2024)

CO2 Solubility and Drilling Fluid Interaction

- **Impact on Drilling Fluid:** CO_2's solubility in synthetic-based mud (SBM) and water-based mud (WBM) changes the properties of the drilling fluid, reducing its effectiveness in maintaining pressure control. This is especially problematic in situations where CO_2 dissolves in the mud and causes volume expansion as it transitions out of solution during pressure reductions.(Manikonda et al., 2021; Skogestad et al., 2024) Special considerations for mud formulation and rheology must be made when operating in CCS environments .(Skogestad et al., 2024)

Valve & Choke Design and Integrity

- **Corrosion and Material Degradation:** CO_2, especially in the presence of water, is corrosive. The interaction between CO_2 and well materials can lead to the degradation of valve and choke integrity, leading to leaks or complete failures. (Zhou et al., 2022, 2024) Special materials, such as corrosion-resistant alloys, are often required in CO_2 applications to ensure long-term equipment integrity. (McMillan et al., 2024)

Well Control Operations in CO2 Wells

Well control operations involve detecting and managing wellbore influxes, such as gas kicks, to prevent blowouts. CO_2 wells, particularly in CCS projects, pose distinct challenges that require modifications to traditional well control procedures.

Detection and Handling of CO_2 Influx

- **Delayed Detection:** CO_2, particularly when in its supercritical phase, is harder to detect during an influx. The solubility of CO_2 in drilling fluids further complicates detection, as the influx may not present itself until a significant volume of CO_2 has dissolved and later evolves out at shallower depths. (Zhou et al., 2022)

- **Thermodynamic Behavior:** As discussed by Skogestad et al. (2024) in *CCS Well Control Impact of CO2 on Drilling Fluid Performance*, CO_2's transition from a supercritical fluid to gas during well control events causes sudden expansion and cooling, which can lead to unexpected pressure fluctuations and temperature drops. (Skogestad et al., 2024) Well control systems must be equipped to handle these rapid changes in fluid behavior.

Modifications to Traditional Well Control Procedures

- **Circulating Out CO2 Kicks:** The traditional Driller's method for circulating out gas kicks must be modified for CO_2 influxes. CO_2's greater liquid velocity and expansion rates compared to methane or oil-based kicks require faster reactions and place greater demands on surface equipment. (McMillan et al., 2024; Zhou et al., 2022) Moreover, additional considerations must be made for the potential formation of hydrates or dry ice near the surface during circulation. (Zhou et al., 2022, 2024)

- **Emergency Shutdown Procedures:** The expansion of supercritical CO_2 poses a risk to emergency shutdown equipment. The rapid volume changes during a blowout or pressure drop may exceed the design limits of conventional well control systems, leading to catastrophic failures if not accounted for in the design stage. (McMillan et al., 2024)

Well Control Simulations

- **Modeling** CO_2 **Behavior:** Well control models that simulate CO_2 behavior are critical in developing strategies to manage kicks and blowouts. For example, Zhou et al. (2022) highlighted the importance of transient multiphase flow simulations in predicting the behavior of CO_2 influxes under different mud types. Such models are essential for designing well control procedures that can handle the unique thermodynamic properties of CO_2.(Zhou et al., 2022)

Section Conclusion

The challenges faced in BOP, pressure control equipment, and well control operations are exacerbated in CO_2 wells due to the distinct properties of CO_2, particularly its supercritical phase behavior and interaction with well materials. Addressing these challenges requires specialized equipment, modified operational procedures, and advanced modeling techniques. Furthermore, industry standards must evolve to include considerations specific to CCS operations, ensuring that well control remains robust in the face of these new challenges.

For successful CCS implementation, ongoing research and development in well control strategies, BOP design, and pressure control systems are essential. As industry transitions towards net-zero goals, understanding and mitigating the risks associated with CCS well control will be critical to ensuring safe and sustainable operations.

Report Conclusion

In conclusion, ensuring the integrity and functionality of well equipment for Carbon Capture and Storage (CCS) is paramount for the safe and sustainable operation of such systems. This report has highlighted the critical factors influencing equipment design, particularly the effects of CO_2 and its components on well components. Key challenges include managing corrosion, material degradation, and the complex behavior of CO_2 in various phases, particularly under injection pressure and temperature conditions. The selection of appropriate materials, continuous monitoring, and the adoption of industry best practices are essential to mitigate risks associated with gas components, phase transitions, and CO_2 properties.

Additionally, the extended lifespan of CCS wells compared to traditional oil and gas wells introduces unique demands on well integrity, requiring robust design features such as dual barriers and efficient use of corrosion-resistant alloys. As the industry continues to evolve, ongoing research and improvements in well control strategies and pressure management will play a critical role in addressing the distinct challenges posed by CCS operations.

Ultimately, the safe and effective implementation of CCS technology will depend on a holistic understanding of the risks and requirements associated with CCS storage, supported by rigorous standards and innovative design solutions.

Bibliography

1. Acevedo, L., & Chopra, A. (2017). Influence of Phase Behaviour in the Well Design of CO2 Injectors. Energy Procedia, 114, 5083-5099. https://doi.org/10.1016/j.egypro.2017.03.1663:contentReference[oaicite:1]{index=1}.
2. Acevedo, L., & Tucker, O. (2022). Managing CO2 Phase Behaviour in Depleted Reservoirs. SPE ADIPEC Conference, Abu Dhabi, UAE. https://doi.org/10.2118/210796-MS:contentReference[oaicite:2]{index=2}.
3. Al Baroudi, H., Mori, S., Patchigolla, K., & Oakey, J. E. (2021). Qualification of Elastomer Materials for CO2 Pipeline Systems. 15th International Conference on Greenhouse Gas Control Technologies (GHGT-15), Abu Dhabi, UAE
4. Al Baroudi, H., Mori, S., Patchigolla, K., & Oakey, J. E. (2024). Evaluation of Elastomer Suitability for CCUS: Chemical Compatibility and Rapid Gas Decompression in Supercritical CO2. Journal of Applied Polymer Science. https://doi.org/10.1002/app.55634:contentReference[oaicite:1]{index=1}.
5. Ansaloni, L., Alcock, B., & Peters, T. A. (2020). Effects of CO2 on Polymeric Materials in the CO2 Transport Chain: A Review. International Journal of Greenhouse Gas Control, 94, 102930. https://doi.org/10.1016/j.ijggc.2019.102930.
6. Bona, P., Fraser, M., & Clifford, A. (2023). Improving Injection Efficiency in CCUS Wells: A Comparative Analysis of Different Completion Designs. SPE ADIPEC Conference, Abu Dhabi, UAE. https://doi.org/10.2118/216187MS&#8203

7. Boufflers, L., Martin, P., Mauger, P., & Rodriguez, D. (2024). CO2 Joule-Thomson Effect: Application on Premium Connections for CCS Well. Carbon Capture Science & Technology, 11, 100185. https://doi.org/10.1016/j.ccst.2023.100185.
8. Ceyhan, I., Pilisi, N., Suryanarayana, P. V., & Krishnamurthy, R. M. (2022). Design of Carbon Capture and Sequestration (CCS) Wells. IADC/SPE International Drilling Conference, Galveston, TX, USA. https://doi.org/10.2118/208738-MS:contentReference[oaicite:8]{index=8}.
9. CO2 Specification JIP. (September 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Introduction to the Guidelines (Rev 2). Wood Group UK Ltd.
10. CO2 Specification JIP. (July 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Work Package 1: Thermodynamics (Rev 2). Wood Group UK Ltd.
11. CO2 Specification JIP. (July 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Work Package 2: Reaction Chemistry (Rev 2). Wood Group UK Ltd.
12. CO2 Specification JIP. (July 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Work Package 4: Safety and Environment (Rev 2). Wood Group UK Ltd.
13. CO2 Specification JIP. (July 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Work Package 6: Compression and Pumping (Rev 2). Wood Group UK Ltd.
14. CO2 Specification JIP. (July 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Work Package 7.1: Metering (Rev 2). Wood Group UK Ltd.
15. CO2 Specification JIP. (July 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Work Package 7.2: Sampling and Analysis (Rev 3). Wood Group UK Ltd.
16. CO2 Specification JIP. (September 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Work Package 10: Geological Storage (Rev 3). Wood Group UK Ltd.
17. CO2 Specification JIP. (September 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Work Package 3: Materials and Corrosion (Rev 7). Wood Group UK Ltd.
18. CO2 Specification JIP. (September 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Work Package 5: Capture and Conditioning (Rev 5). Wood Group UK Ltd.
19. CO2 Specification JIP. (September 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Work Package 8: Pipeline Transport (Rev 4). Wood Group UK Ltd.
20. CO2 Specification JIP. (September 2024). Industry Guidelines for Setting the CO2 Specification in CCUS Chains: Work Package 9: Ship Transport (Rev 4). Wood Group UK Ltd

21. Connolly, S., & Cusco, L. (2007). Hazards from High-Pressure Carbon Dioxide Releases During Carbon Dioxide Sequestration Processes. IChemE Symposium Series, No. 153. Available from Health and Safety Executive (HSE), UK(cusco_connolly_2007_haz...).
22. Craig, B., Rowe, A., Warmack, M., Doll, T. E., & Stevens, C. (2023). Guidelines for the Selection of Corrosion Resistant Alloys for CCS and CCUS Injection Wells. International Journal of Greenhouse Gas Control, 129, 103988. https://doi.org/10.1016/j.ijggc.2023.103988:contentReference[oaicite:5]{index=5}.
23. DNV CO2RISKMAN, "Guidance on CCS CO2 Safety and Environment Major Accident Hazard Risk Management", Documents Level 1 through 4, DNV Report No.: I3IJLJW-2, Re-issued 17 December 2021, Rev 3.
24. DuBose, B. (2020). Steel Corrosion Under Supercritical CO2 Conditions with CCS gas components. Materials Performance Journal.
25. Duguid, A., Kirksey, J., Riestenberg, D., Koperna, G., Holley, C., Loizzo, M., & Locke, R. (2018). CO2 Well Construction: Lessons Learned from United States Department of Energy Sponsored Projects. 14th International Conference on Greenhouse Gas Control Technologies (GHGT-14), Melbourne, Australia.
26. Duncan, I. J., Nicot, J-P., & Choi, J-W. (2009). Risk Assessment for Future CO2 Sequestration Projects Based on CO2 Enhanced Oil Recovery in the U.S.. Energy Procedia, 1, 2037-2042. https://doi.org/10.1016/j.egypro.2009.01.265.
27. El-Kady, A. H., Amin, M. T., Khan, F., & El-Halwagi, M. M. (2024). Analysis of CO2 Pipeline Regulations from a Safety Perspective for Offshore Carbon Capture, Utilization, and Storage (CCUS). Journal of Cleaner Production, 439, 140734. https://doi.org/10.1016/j.jclepro.2024.140734.
28. FSIS Environmental, Safety, and Health Group. (2023). Carbon Dioxide Health Hazard Information Sheet.
29. Guideline for Materials Selection and Corrosion Control for CO2 Transport and Injection. (2023). Association for Materials Protection and Performance (AMPP). https://doi.org/10.4043/21532-MS.
30. Haigh, M. J. (2009). Well Design Differentiators for CO2 Sequestration in Depleted Reservoirs. SPE Offshore Europe Conference, Aberdeen, UK. https://doi.org/10.2118/124274-MS.
31. Holt, H., Helle, K., & Brown, J. (2012). CCS CO2 Risk Management: New Industry Guidance. DNV KEMA. Presented at the Hazards XXIII Symposium, Det Norske Veritas Ltd(CCS CO2 RISK MANAGEMENT...).

32. Inose, K., Abe, T., Yamaguchi, S., Ugai, S., Wada, A., & Ando, Y. (2023). Fundamental Evaluations of the Sealability of Premium Joints in CCS Wells. Offshore Technology Conference, OTC-32149-MS. https://doi.org/10.4043/32149-MS.
33. International Association of Oil & Gas Producers (IOGP). (2024). Design Guidance for Subsea Carbon Capture and Storage Systems (Report No. 665). IOGP Subsea Committee. https://www.iogp.org/bookstore/
34. Ismail, I., & Gaganis, V. (2024). Well Control Strategies for Effective CO2 Subsurface Storage: Optimization and Policies. Materials Proceedings, 15, 74. https://doi.org/10.3390/materproc2023015074.
35. Kamo, Y., Takai, H., & Eguchi, K. (2023). Corrosion Behavior of Martensite-Based Stainless Steels in Chloride Solutions Saturated with CO2 Containing Impurity Gases. Association for Materials Protection and Performance (AMPP), Paper No. 18908
36. Mamrosh, D., McIntush, K., Lundeen, J., & Tyndall, K. (2022). Consider Hazards of CO2 and H2S for CCS. Presented at the Laurance Reid Gas Conditioning Conference, Norman, OK
37. Manikonda, K., Hasan, A. R., Rahmani, N. H., Kaldirim, O., Obi, C. E., Schubert, J. J., & Rahman, M. A. (2021). A Gas Kick Model that Uses the Thermodynamic Approach to Account for Gas Solubility in Synthetic-based Mud. SPE/IADC Middle East Drilling Technology Conference and Exhibition, Abu Dhabi, UAE. https://doi.org/10.2118/202152-MS.
38. Martin, P., Verger, E., Mauger, P., Boufflers, L., Weber, P., Faramarzi, L., & Rodriguez, D. (2022). Tubing Connection Evaluation Methodology and Test Protocol for CCS Injection Wells. 16th International Conference on Greenhouse Gas Control Technologies (GHGT-16), Lyon, France
39. Marya, M. (2023). An Evaluation of Well Completion Materials for Impure Carbon Dioxide Supercritical Streams in Hydrocarbon Production and Geological Carbon Sequestration. Association for Materials Protection and Performance (AMPP), Paper No. MECC2023-20034(Evaluation of Well Comp...).
40. Matsuo, D., Arai, Y., Kanki, K., Sagara, M., & Amaya, H. (2022). Corrosion Resistance of Super Duplex Stainless Steel for CCS Usage under Supercritical CO2 Conditions with CCS gas component Gas. Association for Materials Protection and Performance (AMPP), Paper No. 17602(Corrosion Resistance of...).
41. Mauger, P., Khoo, S., Bochkarev, V., Martin, P., Rodriguez-Barrera, D., Poitrenaud, H., & Sofyan, M. (2024). Qualification Approach of OCTG Connections for CCS Injection Wells: Tubing and Casing. Offshore Technology Conference, OTC-35382-MS. https://doi.org/10.4043/35382-MS:contentReference[oaicite:5]{index=5}.

42. Mauger, P., Martin, P., Boufflers, L., & Rodriguez, D. (2024). Rapid Depressurization and Corrosion Evaluation of OCTG Connections for CCS Injection Wells. Offshore Technology Conference Asia, OTC-34721-MS. https://doi.org/10.4043/34721-MS.
43. McMillan, C. E., Buksh, N. J., McSpadden, A. R., Trevisan, R., & Howard, J. A. (2024). Development of a Fit-For-Purpose CO2 Injection Model for Casing and Tubing Design. IADC/SPE International Drilling Conference and Exhibition, Galveston, TX, USA. https://doi.org/10.2118/217732-MS.
44. McMillan, C. E., Buksh, N. J., McSpadden, A. R., Trevisan, R., & Howard, J. A. (2024). Development of a Fit-For-Purpose CO2 Injection Model for Casing and Tubing Design. IADC/SPE International Drilling Conference, Galveston, TX, USA. https://doi.org/10.2118/217732-MS.
45. Meyer, J. P. (Prepared for the American Petroleum Institute). Summary of Carbon Dioxide Enhanced Oil Recovery (CO2 EOR) Injection Well Technology. Contek Solutions, Plano, Texas.
46. Millet, C., Lima, L., Néel, G., & Rodriguez Barrera, D. (2023). Material Selection for Anthropogenic CO2 Injection: Mechanical and Corrosion Performances of Steels under Dense CO2 with CCS gas components. Association for Materials Protection and Performance (AMPP), Paper No. 18886.
47. Nuclear Regulatory Commission (NRC). (1999). White Paper on Risk-Informed and Performance-Based Regulation. SECY-98-144.
48. Nutricato, G., Repetto, C., Brambilla, R., Dal Forno, L., Santoro, D., Nunzi, P., Martini, L., Eaton, R., Piccolo, A., Zambetti, R., Cordero, J., Goya, M., Santi, N., & Gibellini, E. (2023). Qualification Tests of OCTG Premium Connection under Cryogenic Conditions for CCS Projects. International Petroleum Technology Conference, IPTC-22932-MS. https://doi.org/10.2523/IPTC-22932-MS.
49. Nutricato, G., Repetto, C., Santoro, D., Zucchetto, M. O., Dal Forno, L., Curioni, E., Brambilla, R., Eaton, R., Martini, L., Nunzi, P., Chiu, Y., Nicolò, S., Mantegazza, T., Gibellini, E., Goya, M., Zambetti, R., & Santi, N. (2023). Development of a Test Protocol to Evaluate OCTG Dope-Free Connection Response to Cryogenic Conditions that could appear in Extreme Load Cases of CCS Projects. Offshore Technology Conference, OTC-32366-MS. https://doi.org/10.4043/32366-MS.
50. Oldenburg, C. M., & Pan, L. (2019). Simulation Study Comparing Offshore Versus Onshore CO2 Well Blowouts. Offshore Technology Conference, Houston, TX, USA. https://doi.org/10.4043/29461-MS.

51. Rowe, A. C., & Craig, B. D. (2024). Selection of Corrosion Resistant Alloys for CCS and CCUS Injection Wells. IADC/SPE International Drilling Conference and Exhibition, Paper No. 217664-MS.
52. Salzano, T., Racca, S., Ferrara, G., Nutricato, G., Ricci Maccarini, G., Santi, N., Zambetti, R., Cordero, J., Giraldo, L., & Malesani, S. (2021). Low Temperature Testing of OCTG Premium Connections for CCS Application. 15th OMC Med Energy Conference and Exhibition, Ravenna, Italy.
53. Skogestad, J. O., Feneuil, B., N'Gouamba, E., Linga, H., Aasen, A., Skår, G., Roggeband, S. M., Nedrum, J., & Helgeland, S. (2024). CCS Well Control Impact of CO2 on Drilling Fluid Performance. IADC/SPE International Drilling Conference and Exhibition, Galveston, TX, USA. https://doi.org/10.2118/217711-MS.
54. Sofyan, M., Poitrenaud, H. M., Khoo, S., Chilaka, A., Dechelette, B., & Garcia, E. V. (2024). Proposed Guidelines for Carbon Capture & Storage (CCS) Completions Design in Highly Depleted Reservoirs. Offshore Technology Conference, Houston, TX, USA. https://doi.org/10.4043/35200-MS.
55. Sonke, J., & Paterson, S. J. (2022). Guidance for Materials Selection and Corrosion Control in CO2 Transport and Injection for Carbon Capture and Storage. Association for Materials Protection and Performance (AMPP), Paper No. 17726(Guidance for Materials ...).
56. Spitzenberger, C., & Flechas, T. (2023). CO2 Major Accident Hazards. AIChE: Chemical Engineering Progress, 33-34. Available from American Institute of Chemical Engineers (AIChE).
57. Suling, W., Mingzhan, C., Minzheng, J., & Kangxing, D. (2019). Experimental Evaluation and Mechanism Analysis of Elastomer Failure Caused by Rapid Gas Decompression. IOP Conference Series: Earth and Environmental Science, 242, 032021. https://doi.org/10.1088/1755-1315/242/3/032021.
58. van Haaften, W. M., Bezensek, B., Chambers, B., Amaya, H., Arai, Y., & Kamitani, H. (2023). Material Selection for Carbon Capture and Storage (CCS) Wells. Association for Materials Protection and Performance (AMPP), Paper No. 18760.
59. Van Riet, E., Van Wittenberghe, J., Van Hoecke, D., Roijmans, R., Vanderschueren, M., & Thibaux, P. (2023). On the Suitability of Premium OCTG Tubing Connections for CCS CO2 Injection Wells: A Full-Scale Physical Evaluation. International Journal of Greenhouse Gas Control, 123, 103834. https://doi.org/10.1016/j.ijggc.2023.103834.
60. Vignes, B., Enoksen, A. M., & Ovesen, M. (2010). CO2 Injection and Storage: Qualification of Well Barriers in Adjacent Wells. Offshore Technology Conference, Houston, TX, USA. https://doi.org/10.4043/20724-MS.

61. Wejwittayaklung, K., Toempromraj, W., Jantasuwanna, P., Chanpen, C., Limniyakul, V., Antoneus, S. T., Chotphornphakorn, W., & Thongpracharn, P. (2024). Transient Flow Analysis for Well CO2 Injection: Challenges and Methodologies to Consider for Well Design & Operating Envelope. SPE Oman Petroleum & Energy Show, Muscat, Oman. https://doi.org/10.2118/218552-MS.
62. Zhou, L., Anfinsen, B-T., Hashemian, Y., Yuan, Z., & Mosti, I. (2022). Well Control Considerations for CO2 Wells Based on Multiphase Flow Simulations. SPE Annual Technical Conference and Exhibition, Houston, TX, USA. https://doi.org/10.2118/210132-MS.
63. Zhou, L., Upchurch, E. R., Liu, Y., Anfinsen, B-T., Hashemian, Y., & Yuan, Z. (2024). Evaluating Subsea Capping Stack Usage for CO2 Blowouts. Offshore Technology Conference, Houston, TX, USA. https://doi.org/10.4043/35246-MS.

CO_2 / CCS / CCUS Well Equipment – Considerations
Comment Only Ballot Draft – XX Oct. 2024

Annex A: API SC16 Equipment Critical Questions

The following set of critical questions were developed and reviewed by the SC16 CCS Ad Hoc Work Group. These questions are intended to help individuals develop CCS related verbiage for the 16A, 16C, Std 53, and RP 59 standards.

BOP Equipment - API Spec 16A Bucket List:

Note1: More CO_2 influx modeling work would be beneficial to better understand the potential temperature ranges within the BOP and both upstream and downstream of the choke when circulating out a CO_2 influx.

1. Will predicted colder influx surface operating temperatures for CO_2 gas compositions affect annular preventer, ram side packers, top seals, and ram piston cylinder wellbore side seals?

2. Will Joule-Thomson cooling adversely affect the metallurgy of BOP metal components during short term exposure limits if circulating a CO_2 influx to surface?

3. Will probability for metal brittle fracture failure, corrosion, or erosion be more than a low risk during short time exposure duration? What is definition for short term exposure?

4. Will probability for metal brittle fracture failure, corrosion, or erosion be more than a low risk during long time exposure duration? What is definition for long term exposure?

5. Will different metal and elastomer seal qualification tests be needed than currently specified in 16A?
   - API 16A, Table 3, currently lists Temperature Ratings for Metallic Materials with ranges from -59 deg C (-75 deg F) to 177 deg C (350 deg F). Will CO_2 influx temperature at surface be within the current BOP manufacturing specification? Should design spec be upgraded to a lower temperature rating.
   - API 16A, Table 4, lists seven non-metallic codes for seals used in BOP equipment for three different operating temperature conditions. The most severe low temperature non-

metallic condition calls for a rating of -26 deg C (-15 deg F). Will CO_2 influx temperature at surface be within the current BOP manufacturing specification?

6. Will elastomer seals suffer more explosive degradation during short term exposure to lower temp wellbore conditions considering various levels of CCS gas components within the CO_2 flow stream?

7. Is industry currently able to qualification validate BOP elastomer (non-metallic) seals and metallic components exposed to wellbore fluid at anticipated CO_2 low temp extremes?

8. Is additional testing required using various percents of CO_2 gas concentrations to validate acceptable cold and CO_2 exposure limits for elastomers?

9. Should the failure modes for elastomers considering CO_2 gas, CCS gas components, and cold temperature environment be defined (i.e., cracking, erosion, explosive degradation, sorption, swelling, contraction of seal, etc.)?

Choke and Kill Equipment - API Spec 16C Bucket List:

Note2: Conditions upstream and downstream of the choke are expected to be much different during conventional well control operations. Downstream of the choke is expected to produce conditions much more severe to equipment. Upstream of choke designated by UC, downstream of choke by DC.

1. Will Joule-Thomson cooling adversely affect the metallurgy of steel choke line components between the BOP and the choke manifold valves during short term exposure limits if circulating a CO_2 influx to surface? **(UC)**

2. Will Joule-Thomson cooling adversely affect choke line flexible hose inner lining material between the BOP and the steel choke lines during short term exposure limits if circulating a CO_2 influx to surface? **(UC)**

3. Will possible "severe" Joule-Thomson cooling adversely affect the metallurgy of the choke manifold, manifold outlet lines, and MGS? **(DC)**

4. Will probability for metal brittle fracture failure, corrosion, or erosion be more than a low risk during short time exposure duration? What is definition for short term exposure? **(UC+DC)**

5. Will probability for metal brittle fracture failure, corrosion, or erosion be more than a low risk during long time exposure duration? What is definition for long term exposure? **(UC+DC)**

6. Will different metals and qualification tests be needed than currently specified in 16C? **(UC+DC)**
   - API 16C, Table 1, currently lists Temperature Ratings for Metallic and Nonmetallic Materials and Flexible Lines with ranges from -60 deg C (-75 deg F) to 177 deg C (350 deg F).
   - Will CO_2 influx temperature at surface be within the current API 16C manufacturing specification? Should design spec be upgraded to a lower temperature rating.

7. Will elastomer seals suffer more degradation during short term exposure to lower temp wellbore conditions considering various levels of CCS gas components in the flow stream? **(UC+DC)**

8. Is industry currently able to validate choke and kill equipment elastomer (non-metallic) seals and metallic components exposed to wellbore fluid to anticipated CO_2 low temp extremes?

9. Is additional industry testing required using various percents of CO_2 gas concentrations to validate acceptable cold exposure for elastomers?

10. Should the failure modes for elastomers considering CO_2 gas, CCS gas components, and cold temperature environment be defined (i.e., cracking, erosion, explosive degradation, sorption, swelling, contraction of seal, etc.)? **(UC+DC)**

11. Should use of single pressure rated choke manifolds instead of dual pressure rated manifolds be recommended for CO_2 operations (i.e., 10k RWP manifold upstream of the chokes can be 5k psi RWP downstream of chokes)?

12. Should the bleed (panic) line to the pit or overboard be considered an extension of the choke manifold and be rated to manifold RWP downstream of the choke?

13. Should it be recommended that surface choke manifolds have two redundant auto chokes and one manual choke for operations on CO_2 wells (due to hydrate and erosion concerns)?

14. Should it be recommended that dual auto chokes have independent inlets into one MGS or that each choke have its own independent MGS?
    - Two independent chokes and MGSs would provide full redundancy if one choke line hydrated up during a well kill procedures.

15. Should 16C address injection equipment to pump hydrate inhibitors (i.e., ethylene glycol) into the choke system to help control hydrate formation while circulating out a CO_2 influx? **(UC)**
    - Hydrates in CO2 kicks will be a concern if free water is present in mud, brine or influx.

16. Should insulation and heat tracing wrap (such as used in gas plant technology, Arctic wells, cold weather environments, etc.) be recommended on surface choke lines and choke manifold lines? Is technical work needed to understand what is adequate? Need to understand what technologies are available. **(UC+DC)**

17. Should industry equipment recommendations for flare stacks and flaring be developed and included in API 16C?
    - Not for igniting but to elevate CO_2 gas into the wind above ground level downstream of the rig and personnel.

18. Does NACE MR0175/ISO 15156 adequately address CO_2 gas in wellbore fluid concerns to metallic materials?
    - API 16C, item 4.2.3, states that metallic materials exposed to wellbore fluid share confirm to the requirements of NACE including the H2S partial pressure rating.

19. Should the list of written specifications for nonmetallic parts in API 16C, Section 5.3, include exposure to CO_2 environments.

20. Should the manufacturer's written specification referenced in API 16C, Section 7.3.5, for pressure-controlling nonmetallic parts include CO_2 capability?

21. Are the test fluid compositions listed in API 16C, Section A.7.4.2 adequate for CO_2 operations.
    - For CO_2 operations would the following gas concentrations best represent the wellsite conditions: Test Fluid A and B (85% CO_2, 5% methane, 10% H2S), Fluid C (80% CO_2, 10% methane, 10% H2S)?

Well Control Equipment Systems for Drilling Wells - API Std 53 Considerations:

1. BOP stack metallic classification considerations for use on CO_2 wells.
2. BOP stack operational guidance for non-metallic code to use for CO_2 well.
3. Add CO_2 to the seal verification statement for HPHT wells in Item 4.5.6.4.
4. Crack and erosion NDT inspections on specific equipment similar to current guidance in 4.2.2.5 and 4.2.4.3.
    - The choke manifold piping downstream of the chokes would be a likely candidate for inspection after circulating a CO_2 kick through the system or at some periodic time interval.

Well Control Operations - API RP 59 Considerations:

Note3: specific well control actions when dealing with CO_2**.**

Note4: The possible risks of circulating CO_2 **to surface summarized**

Note5: Preferred method of well control – bullheading?. This applies to both drilling and well work operations.

Note6: Hydrates in CO_2 **kicks will be a concern if free water is present in mud, brine or influx.**

Note7: More CO_2 **modeling is needed to better understand the worst-case conditions in annulus, in the stack, and downstream of the choke.**

1. Will CO_2 hydrate formation be more of a concern upstream of the choke than Methane gas?
2. Will CO_2 hydrate formation be more of a concern downstream of the choke than Methane gas?

3. Are present methane gas hydrate formation models representative of CO_2 gas reactions or should CO_2 gas be used to develop specific hydrate modeling pressure/temperature curves for CO_2 gas and expected CO_2 temperature ranges?

4. Should use of hydrate inhibitive fluids which have been tested to the expected or worst-case CO_2 exposure conditions be recommended? Should procedures consider mitigators aimed at preventing hydrates to form in BOP bore and behind ram cavities?
    - Need definitions of worst-case conditions in annulus, in the BOP stack, upstream of the choke, and downstream of the choke.

5. Should bullheading the CO_2 gas back into the CO_2 flood reservoir be considered the primary method of well control?

6. Should well design be planned to allow CO_2 bullheading operations to be performed successfully without causing underground flow between the flow zone and last casing shoe?

7. Should it be specified that well specific fit-for-purpose surface equipment capable of handling CO_2 gas/returns be available if circulating a CO_2 influx to surface is required?

8. Should site-specific CO_2 well control procedures be developed and approved?

9. Should the use of hydrate inhibitive fluids which have been tested to expected or worst-case CO_2 exposure conditions be recommended (at least 24 hours static condition without hydrate formation using well-specific gas, pressure, temp, and free water)?

10. Should slower well kill circulating rates be recommended to help string out CO_2 gas in the annulus and help control or reduce explosive free gas breakout at surface? Additional CO_2modeling would help answer the questions.

11. Should slow circulating rate be recommended when influx is close to surface to allow choke operator to have more reaction time?

12. Should any specific choke operational concerns be addressed for handling a CO_2 influx?
    - Goal is to prevent taking a second CO_2 kick from mishandling the choke when the first kick surfaces.

- Choke actuator speed and accuracy when opening and closing the choke to handle gas returns at surface will be critical to manage.

13. Should a Coriolis meter be added as a flow rate monitoring option for early detection of a CO_2influx?

14. Should CO_2 migration in clear fluids with the well shut in be addressed?

15. Will fluid rheology and fluid weight be more affected in a CO_2 influx than methane influx while CO_2 goes into solution deep and then transitions fluid phase to gas phase up the hole?

16. Will fluid thinning (rheology effects) in a CO_2 influx encourage a higher degree of barite and solids fallout than in a methane kick. Review effects this might have on fluid density and solids settling.