# Application of JFE-UHP™-15CR-125 and JFE-UHP™-17CR-110 to $CO_2$ Injection (CCS/CCUS) Tubing for Geological Storage

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***Abstract:***

*Interest in carbon neutrality to suppress global warming is growing around the world, with many countries targeting Net-Zero $CO_2$ emission scenarios. Carbon dioxide Capture and Storage (CCS) which is a technology for injection and storage of $CO_2$ in geological layers, and Carbon dioxide Capture, Usage and Storage (CCUS), in which $CO_2$ is injected into depleted oil and gas fields and used simultaneously for secondary recovery of remaining oil and natural gas, are attracting attention as methods that can contribute to achieving carbon neutrality. For underground injection of $CO_2$, it is necessary to construct well equipment almost equivalent to an oil or natural gas production well, and inject $CO_2$ underground through the steel tubing pipes in the center of the well. This paper describes the performance required in tubing pipes for $CO_2$ underground injection and the applicability of JFE Steel's OCTG pipes, including the UHP™ series, which are proprietary JFE steel materials.*

## 1. Introduction

At the 21st Conference of the Parties (COP) to the United Nations Framework Convention on Climate Change (UNFCCC) held in 2015, an international multilateral agreement on climate change mitigation (commonly known as the Paris Agreement) was agreed upon by 159 participating countries. This agreement includes the following three goals[1)] to curb global warming:

1. Achieving net-zero $CO_2$ emissions (carbon neutrality) by the latter half of the 21st century.
2. Limiting the global average temperature increase to below 2°C compared to pre-industrial levels.
3. In addition to the above, pursuing efforts to limit the temperature increase to 1.5°C.

Following the conclusion of the Paris Agreement, the momentum for decarbonization has rapidly increased worldwide. JFE Steel also declared its commitment to achieving carbon neutrality by 2050 in its Environmental Management Vision 2050[2)]. To achieve carbon neutrality, it is necessary to either reduce the $CO_2$ emissions released into the atmosphere or convert them to other substances for reuse through Carbon dioxide Capture and Utilization (CCU). Many research and development efforts are being made toward practical implementation. Among these, Carbon dioxide Capture and Storage (CCS), which involves injecting and fixing $CO_2$ underground, and Carbon dioxide Capture Usage, and Storage (CCUS), which involves injecting $CO_2$ into depleted oil and gas fields to simultaneously recover remaining oil and natural gas and sequester the $CO_2$, are attracting attention. Actual projects are already underway, but at this stage, the operational methods and materials used are not standardized, and each customer is proceeding through trial and error.

This paper discusses the currently known required properties of steel pipes for $CO_2$ injection in CCS/CCUS and the applicability of JFE oil country tubular goods (OCTG).

## 2. Overview of CCS/CCUS

A conceptual diagram of CCS is shown in **Fig. 1**. First, exhaust gas containing various corrosive components such as $CO_2$, SOx, NOx, $O_2$, $H_2$, and $H_2S$ is emitted from $CO_2$ source facilities such as power plants, oil and natural gas refineries, hydrogen produc-

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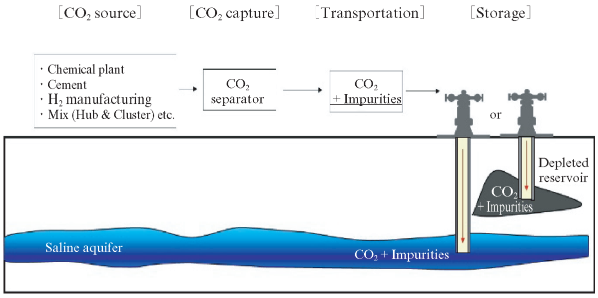


Fig. 1 Schematic diagram of CCS

tion facilities, and various chemical plants. A high-purity $CO_2$ gas stream is extracted from this exhaust gas by separation and recovery equipment (Capture) that separates and recovers only $CO_2$. $CO_2$ separation and recovery methods include membrane separation, which uses separation membranes to physically separate $CO_2$, physical adsorption methods, chemical adsorption methods, and amine absorption methods, where $CO_2$ is adsorbed by a low-temperature amine solution and then desorbed at high temperature. Currently, the amine absorption method is commonly used[3]. After separation, the high-purity $CO_2$ is transported to the storage site by transport trucks or pipelines, although methods using $CO_2$ transport ships are also being considered. After transportation, the $CO_2$ is injected into depleted oil and gas wells or deep saline aquifers, where it remains in the fine pores of the geological formations or in the formation water, eventually mineralizing and stabilizing over time.

$CO_2$ injection wells are designed using casing and tubing steel pipes with premium joints, which are typically used for oil and natural gas production wells. The injected $CO_2$ is transported through the tubing pipes from the surface or offshore to the injection site for storage. In the case of CCUS, the goal is not pure storage but secondary recovery of remaining oil and gas by injecting $CO_2$ into depleted oil and gas wells to increase the reservoir pressure. Although the usage period is shorter than that of CCS, the basic well design for CCUS and CCS is similar.

## 3. $CO_2$ Injection Tubing

### 3.1 Corrosion Resistant Performance Required in $CO_2$ Injection Tubing

This section describes the performance required in steel pipes used for $CO_2$ injection. When $CO_2$ is present during oil and gas production, there is a concern that high-temperature, high-pressure $CO_2$ dissolved in low pH formation water may corrode the steel. Therefore, steel pipes with 13% Cr or higher are typically used as tubing steel pipes instead of carbon steel. Generally, the concentration of $CO_2$ contained in underground oil and natural gas reservoirs is low, and is at most about 30% even in commercially producing wells. On the other hand, the purity of the $CO_2$ fluid injected in CCS, as mentioned in Chapter 1, is mostly of 95% or higher because only $CO_2$ is separated and recovered from the original exhaust gas. Consequently, steel pipes for $CO_2$ injection are exposed to high-temperature, high-pressure, and high-concentration $CO_2$, especially at the bottom of the well, which increases the concern regarding $CO_2$ corrosion compared to oil and gas production wells. Additionally, in CCS, the injected $CO_2$ may contain acidic substances (SOx, NOx, etc.) derived from the emission source and impurities that promote steel corrosion. Therefore, higher corrosion resistance is required in the tubing steel pipes that come into direct contact with these substances than those used for oil and gas production. **Table 1** shows the effects of various impurities contained in the $CO_2$ stream on steel.

Table 1 Effect of impurities in $CO_2$ stream

| Element | $CO_2$ | $SO_2$ | $NO_2$ | $O_2$ | $H_2$ | $H_2S$ |
|---|---|---|---|---|---|---|
| Effect | General corrosion (Drives water pH lower) | | | Pitting | Hydrogen embrittlement | |

As explained earlier, $CO_2$ dissolves in water, lowering the pH of formation water and promoting dissolution and corrosion of steel. SOx and NOx, like $CO_2$, dissolve in water and release $H^+$ ions, further lowering the pH and making the steel more susceptible to corrosion. $O_2$ also dissolves in water and acts as an oxidizing agent, increasing the risk of pitting and crevice corrosion of steel. High concentrations of $H_2$ can cause hydrogen embrittlement in steel due to hydrogen ingress, and $H_2S$ acts as a catalyst to promote hydrogen ingress into steel. Except for $H_2S$, these impurities are not typically found in conventional oil and gas production wells. From this perspective, steel pipes for $CO_2$ injection must have corrosion resistance in environments containing such corrosive substances.

### 3.2 Corrosion Test Procedure and Results Simulating $CO_2$ Injection Condition

**Figure 2** shows the state of $CO_2$ injection and shut-in in CCS.

During $CO_2$ injection, dehydrated $CO_2$ passes through the steel tubing pipes and is injected into the formation at high pressure. Therefore, the tubing pipes are not in contact with water, and the risk of corrosion is considered extremely low. However, in CCS, $CO_2$ injection may be temporarily interrupted due to the operational status of the $CO_2$ emission equipment, reg-

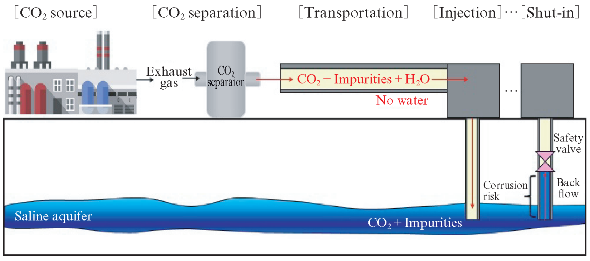


Fig. 2 Corrosion risk of $CO_2$ injection tubing

Table 2 Corrosion test condition and results simulating

| | | Unit | Value, Result |
|---|---|---|---|
| Gas | $CO_2$ | vol.% | Balance |
| | $SO_2$ | ppm | 20 |
| | $NO_2$ | ppm | 85 |
| | $O_2$ | ppm | 80 |
| Liquid | $Cl^-$ | ppm | 30 300 |
| | $H_2O$ | ppm | Solution |
| Temperature<br>Pressure | | Deg.C<br>MPa | 120<br>40 |

ular maintenance, or adjustments to the injection rate. During such interruptions, the sub-surface safety valve (SSSV) installed inside the well is closed, but formation water may rise due to formation pressure. As a result, the tubing steel pipes below the SSSV may come into contact with both high-temperature, high-pressure $CO_2$ fluid and water simultaneously, posing a risk of corrosion. Therefore, high-temperature, high-pressure corrosion tests were conducted to evaluate the corrosion resistance of JFE's OCTG under these conditions.

These corrosion tests were conducted by placing the test specimens in an autoclave set to a high temperature and high pressure. The materials used were JFE-UHP™-15CR-125[4)] and JFE-UHP™-17CR-110[4)5)]. The test conditions are shown in **Table 2**.

To simulate a project where $CO_2$ is separated and recovered from power plant exhaust gas and injected underground, $SO_2$, $NO_2$, and $O_2$ generated in the fuel combustion process at the power plant were included in the test. The chloride concentration of the formation water at the injection site varies by location, but was set to 30 300 ppm in this test. Since oxygen is included in the conditions in Table 2 reproduced using the autoclave, there is a possibility of crevice corrosion occurring at the threaded parts of the steel pipes rather than the steady parts of their inner surface. Therefore, a crevice corrosion test was conducted according to ASTM G48. To evaluate stress corrosion cracking resistance, four-point bend test specimens were also prepared according to NACE TM0316 (2016) and

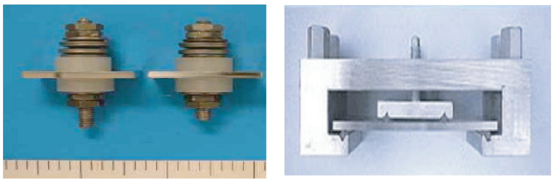

Photo 1 Crevice corrosion and four-point bend specimen

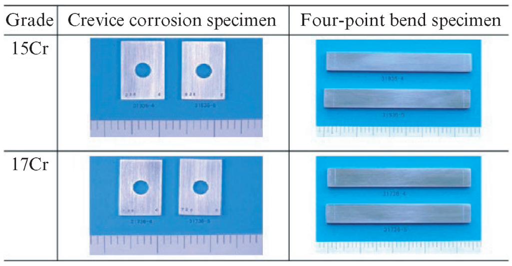


Photo 2 Appearances of specimens after test

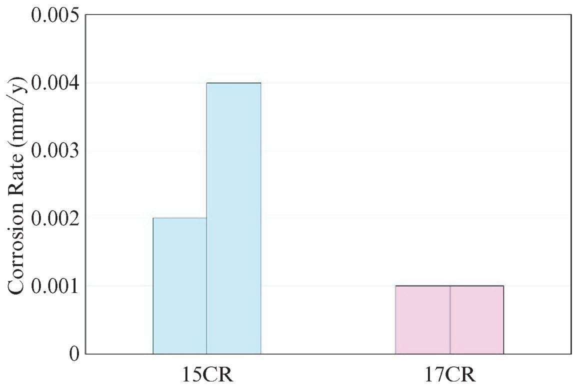


Fig. 3 Corrosion rate of 15CR and 17CR

placed inside the autoclave, and the specimens were evaluated after 720 hours. **Photo 1** shows the crevice corrosion test specimens and four-point bend test specimens, and **Photo 2** shows the specimens after cleaning and removal of the corrosion products after the test.

Visual inspection and observation with a 10x optical microscope revealed no crevice corrosion or cracks in the four-point bend test specimens. **Figure 3** shows the corrosion rate (mm/y) calculated from the weight loss of the crevice corrosion test specimens.

The average corrosion rate in this environment was 0.003 mm/y for JFE-UHP-15CR-125 and 0.001 mm/y for JFE-UHP-17CR-110. Although there are currently no clear standards or guidelines on the acceptable corrosion allowance for actual CCS injection well tubing pipes, and the criteria may vary depending on the expected service life, the corrosion rates under these conditions are considered to be sufficient to withstand long-term injection.

## 4. Temperature Decrease of Tubing Pipes by Cold Gas

In Carbon Capture and Storage (CCS), high-pressure $CO_2$ is injected underground. Since a rapid pressure drop can occur when high-pressure $CO_2$ is injected into low-pressure areas such as depleted wells, causing a decrease in the temperature of the $CO_2$ due to the Joule-Thomson effect[6] and adiabatic expansion, low-temperature toughness will be an important performance requirement for $CO_2$ injection pipes. It has been noted that the temperature of $CO_2$ can decrease to -78.5°C, which is the sublimation temperature at 1 atm[7]. However, it can be assumed that the temperature of the steel pipes will not decrease to a temperature as low as that of the $CO_2$ itself due to the heat capacity of the steel pipes. Nevertheless, the extent of the temperature decrease of the steel pipes is important information for establishing appropriate material selection guidelines. This chapter presents the results of a tubing pipe cooling experiment using low-temperature gas, and the evaluation of the low-temperature toughness of the martensite-based stainless steels which are candidate materials for $CO_2$ injection pipes.

### 4.1 Tubing Pipe Cooling Experiment

#### 4.1.1 Experimental

**Figure 4** is a schematic diagram of the test specimen used in the cooling experiments. The material was JFE-HP2-13CR-95. In actual applications, steel pipes are used by connecting the main steel pipe body (pin), which has male threads, to a short coupling pipe with female threads. The test specimen used in this study replicates this connection and has an overall length of approximately 1.4 meters. An end cap was attached to the bottom of the specimen to prevent fluid leakage from the lower end. Thermocouples were attached at three locations on the specimen, and the temperature was monitored continuously. One thermocouple was placed at the axial center of the steel pipe just above the coupling to measure the temperature of the low-temperature gas inside the pipe (this temperature will be referred as the temperature of the atmosphere), and the other two thermocouples were attached to the inner surface of the pin at the coupling and the outer surface of the coupling.

In the cooling experiment, the entire steel pipe was first heated to 90°C to simulate the geothermal heating conditions that injection pipes would experience in actual use. After the temperature of the pipe became stable at 90°C, heating was stopped and liquid nitrogen (-196°C) was immediately introduced from the top of the pipe. The time at this moment was defined as "zero." The introduced liquid nitrogen accumulated at the end cap at the bottom of the specimen, and the cold nitrogen gas evaporated from the liquid nitrogen, reached the coupling section, and then cooled the pipe. The liquid nitrogen at the end cap was discharged from the pipe 11 minutes after introduction.

#### 4.1.2 Results and Discussion

**Figure 5** shows the measurement results. Immediately after introduction of the liquid nitrogen, the temperature of the atmosphere dropped to between -50°C and -100°C. The temperature on the inner surface of the pin also decreased, but remained 50°C to 100°C higher than the temperature of the atmosphere. This experiment revealed that the temperature of the steel did not drop as low as the temperature of the atmosphere, even on the inner surface of the pipe, which is expected to have the lowest temperature. At $t$ = 11 min, when the liquid nitrogen was discharged, the temperature on the outer surface of the coupling was approximately 50°C, which was 50°C higher than the temperature on the inner surface of the pin. After the liquid nitrogen was discharged, the temperature difference between the inner surface of the pin and the outer surface of the coupling decreased. This decrease was mainly caused by the temperature increase on the inner surface of the pin. **Figure 6** shows a schematic diagram of the estimated temperature gradient at $t$ = 11 minutes. The experimental results indicated that the temperature

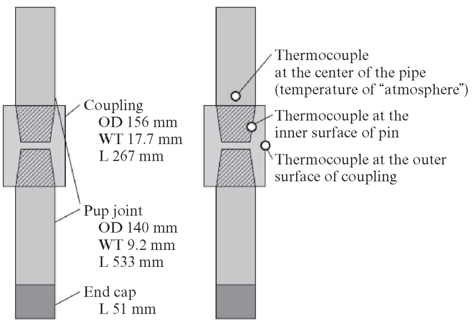


Fig. 4 Samples of cooling experiment

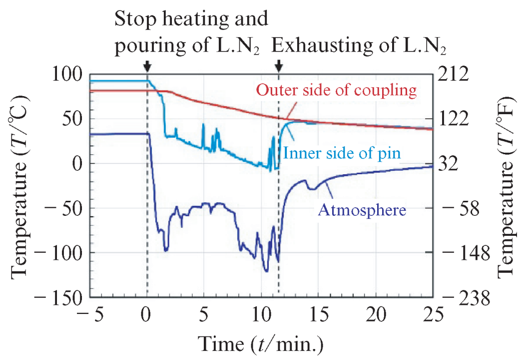


Fig. 5 Temperature transition during cooling

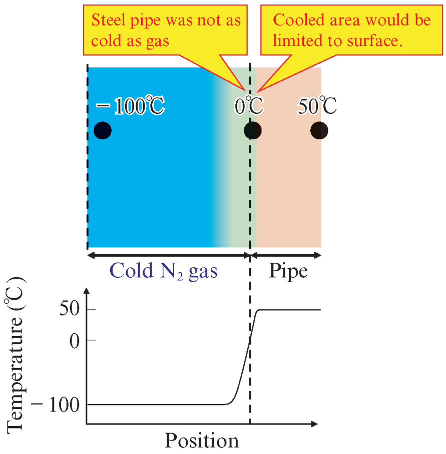


Fig. 6 Temperature gradient of pipe wall and $N_2$ gas

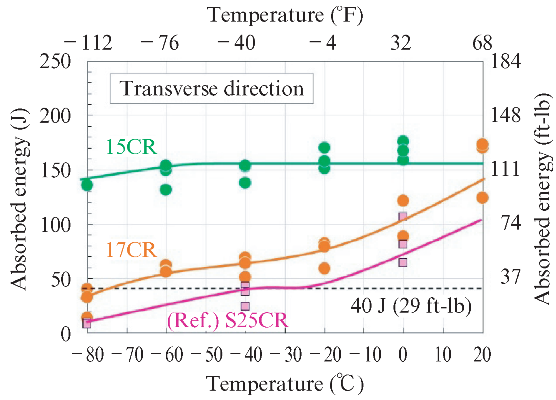


Fig. 7 Relationship between Charpy absorbed energy and temperature

of the inner surface of the steel pipe is higher than that of the low-temperature gas. Based on the fact that the reduction in the temperature difference between the inner and outer surfaces was mainly caused by an increase in the temperature of the inner surface of the pipe, it is thought that the region of the steel pipe experiencing a temperature drop is limited to the vicinity of the inner surface, and the temperature near the center of the pipe wall thickness is close to that of the outer surface. Thus, these experimental results revealed that the actual temperature of the steel pipe does not decrease to the same extent as the temperature of the low-temperature gas itself. However, a quantitative evaluation by heat transfer analysis will be necessary to establish the most appropriate material selection.

### 4.2 Low-Temperature Toughness of Martensite-Based Stainless Steels

**Table 3** shows the materials used for the evaluation of low-temperature toughness. The materials were steel pipes made of JFE-UHP™-15CR-125 (15CR steel) and JFE-UHP™-17CR-110 (17CR steel). For comparison, a steel pipe made of 25Cr super duplex stainless steel (S25CR) was also used. Charpy test specimens were machined from the steel pipes such that the longitudinal direction of the test specimen matched the circumferential direction of the pipe. The Charpy impact tests were conducted in the temperature range of -80°C to 20°C, and were performed in accordance with ASTM E23. **Figure 7** shows the relationship between the temperature of the Charpy test specimens and absorbed energy. The absorbed energy of the 15CR steel remained constant at approximately 150 J or higher at temperatures above -80°C, indicating that this steel retained ductility down to -80°C. However, the absorbed energy of the 17CR steel decreased as the temperature decreased within the range of 20°C to -80°C. The S25CR steel also exhibited temperature dependence similar to that of the 17CR steel, but its absorbed energy was approximately 20 to 30 J lower than that of the 17CR steel.

Although there are no standards specifying the low-temperature toughness of injection pipes for CCS, according to ISO 13680[8], which specifies the low-temperature toughness of corrosion-resistant alloys for oil well pipes, the specified absorbed energy should be 40 J or higher. The 15CR steel maintained an absorbed energy of 40 J or higher down to -80°C, and the 17CR steel maintained this level down to at least -60°C, suggesting that these materials are applicable in terms of low-temperature toughness.

## 5. Conclusion

In this paper, we have organized the characteristics required for steel pipes used for $CO_2$ injection in CCS applications and evaluated the applicability of JFE oil country tubular goods (OCTG). The results demon-

Table 3 List of evaluated materials in low temp. toughness

| Sample ID | UNS No. | C | Cr | Ni | Mo | Others | SMYS (MPa/ksi) | Pipe size (OD×WT) |
|---|---|---|---|---|---|---|---|---|
| 15CR | S42625 | 0.03 | 14.7 | 6.3 | 2.0 | 1Cu added | 862/125 | 203.0×26.8 |
| 17CR | S42825 | 0.03 | 16.7 | 3.9 | 2.5 | 1Cu and 1W added | 758/110 | 201.5×26.8 |
| S25CR | S32760 | 0.02 | 25.8 | 7.1 | 3.7 | 0.6Cu-0.5W-0.26N | 862/125 | 120.7×25.5 |

strated that use is sufficiently possible. As of 2024, new CCS projects are increasing on a daily basis, both overseas and in Japan. We intend to further expand the market for JFE OCTG as steel pipes for $CO_2$ injection, contributing to our customers and the global spread of a decarbonized society.

Figures 4, 5, 6, and 7 and Table 3 are modified and used with permission by AMPP (©AMPP 2024, used with permission.)

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